HARVEST ENERGY TRUST

2003 RENEWAL ANNUAL INFORMATION FORM

APRIL 30, 2004

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

The Trust is hereby providing cautionary statements identifying important factors that could cause the Trust's actual results to differ materially from those projected in forward-looking statements made in this Annual Information Form. Any statements that express or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always through use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "estimated", "intends", "plans", "projection" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Annual Information Form, and particularly in the risk factors set forth herein under "Risk Factors". Because actual results or outcomes could differ materially from those expressed in any forward-looking statements of the Trust made by or on behalf of the Trust, investors should not place undue reliance on any such forward-looking statements. Further, any forward-looking statement speaks only as of the date on which such statement is made, and the Trust undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by law including applicable securities laws. New factors emerge from time to time, and it is not possible for management of the Corporation to predict all of such factors and to assess in advance the impact of each such factor on the Trust or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

SUPPLEMENTAL DISCLOSURE

Distributable cash and cash available for distribution and cash-on-cash yield are not recognized generally accepted accounting principles. Management believes that in addition to net income and net income per Trust Unit, distributable cash and cash available for distribution are useful supplemental measures as they provide investors with information on cash available for distribution. 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. Investors are cautioned that distributable cash, cash available for distribution and cash-on-cash yield should not be construed as an alternate to net income as determined by Canadian generally accepted accounting principles. **Investors 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 full return of the principal amount of debt on maturity in addition to a return on investment through interest payments.**

GLOSSARY OF TERMS

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

"ABCA" means the *Business Corporations Act* (Alberta), together with any or all regulations promulgated thereunder, as amended from time to time.

"Administration Agreement" means the agreement dated September 27, 2002 between the Trustee and the Corporation pursuant to which the Corporation provides certain administrative and advisory services in connection with the Trust. See "Description of the Trust" and "Information Respecting the Corporation".

"Affiliate" means, with respect to the relationship between corporations, that one of them is controlled by the other or that both of them are controlled by the same Person and for this purpose a corporation shall be deemed to be controlled by the Person who owns or effectively controls, other than by way of security only, sufficient voting shares of the corporation (whether directly through the ownership of shares of the corporation or indirectly through the ownership of shares of another corporation or otherwise) to elect the majority of its board of directors.

"ARTC" means the Alberta Royalty Tax Credit, an Alberta provincial government program under which, in certain circumstances, tax credits may be provided against royalties on oil and natural gas production payable to the Province of Alberta.

"Board of Directors" or **"Harvest Board"** means the board of directors of the Corporation.

"Bridge Agreements" means, collectively, the Bridge Notes and the Equity Bridge Notes.

"Bridge Lenders" means, collectively, Caribou and the Chairman of the Corporation.

"Bridge Notes" means, collectively, the bridge notes dated September 29, 2003 between the Trust and each of the Bridge Lenders providing for advances of up to $30 million to the Trust to assist with the payout of the then existing credit facility and the payment of the Deferred Purchase Price Obligation as a result of the acquisition of the Carlyle Properties.

"Business Day" means a day, other than a Saturday, Sunday or statutory holiday in the Province of Alberta or any other day on which banks in Calgary, Alberta are not open for business.

"Capital Fund" means the cumulative amount of funds that the Trust retains from Cash Available For Distributions to finance future acquisitions and development of properties. See "Description of the Trust – Capital Fund".

"Caribou" means Caribou Capital Corp.

"Carlyle Properties" means various working, royalty, proprietary 3D seismic and other interests acquired pursuant to the Carlyle Properties Transaction as described under "Acquisition of Carlyle Properties".

"Carlyle Properties Acquisition Agreement" means the agreement of purchase and sale between the Carlyle Properties Vendor and the Corporation dated effective October 1, 2003 for the purchase of the Carlyle Properties.

"Carlyle Properties Transaction" means the acquisition of the Carlyle Properties by the Corporation pursuant to the Carlyle Properties Acquisition Agreement.

"Carlyle Properties Vendor" means a senior oil and natural gas partnership.

"Cash Available For Distribution" means, for any particular period, all amounts available for distribution during any applicable period by the Trust to holders of Trust Units prior to any retention by the Trust for the Capital Fund. See "Description of the Trust – Cash Available For Distribution".

"COGPE" means Canadian oil and natural gas property expense, as defined in the Tax Act.

"**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;

"Corporation" means, as the context requires, the Trust's wholly-owned subsidiary, Harvest Operations Corp., a corporation amalgamated under the *Business Corporations Act* (Alberta) on January 1, 2004 and, prior to January 1, 2004, a corporation incorporated under the *Business Corporations Act* (Alberta);

"Corporation" means Harvest Operations Corp., a wholly-owned subsidiary of the Trust, and its wholly-owned subsidiaries.

"Current Bank Facility" means the credit facility provided by the Current Lender as more fully described under "Information Respecting the Corporation – Borrowing by the Corporation".

"Current Lender" means a syndicate of lenders comprised of two Canadian chartered banks and Alberta Treasury Branches.

"Debenture Indenture" means the trust indenture dated January 29, 2004 made among the Trust, the Corporation and the Debenture Trustee, as trustee.

"Debenture Trustee" means the trustee of the Debentures, Valiant Trust Company.

"Debentures" means the 9% convertible unsecured subordinated debentures of the Trust due May 31, 2009.

"Deferred Purchase Price Obligation" means, collectively, the ongoing obligation of the Trust to pay to the Corporation and HST, to the extent of the Trust's available funds, an amount equal to 99% of the cost of, including any amount borrowed to acquire, any Canadian resource property acquired by the Corporation or HST, and the cost of, including any amount borrowed to fund, certain designated capital expenditures in relation to the Properties.

"Direct Royalties" means royalty interests in petroleum and natural gas rights acquired by the Trust from time to time pursuant to a Direct Royalties Sale Agreement.

"Direct Royalties Sale Agreement" means any purchase and sale agreement between the Trust and an Operating Subsidiary providing for the purchase by the Trust from an Operating Subsidiary of Direct Royalties.

"Distributable Cash" means, for any particular period, the Cash Available For Distribution less any amounts retained by the Trust for the Capital Fund.

"**DRIP Plan**" means the Trust's Distribution Reinvestment and Optional Unit Purchase Plan.

"Equity Bridge Notes" means, collectively, the equity bridge notes dated July 28, 2003 and amended September 29, 2003 between the Trust and each of the Bridge Lenders providing for advances of up to $40 million to the Trust to assist in the payout of the Corporation's then existing credit facility and the payment of the Deferred Purchase Price Obligation as a result of the Carlyle Properties Transaction.

"Exchangeable Shares" means the non-voting exchangeable shares in the capital of the Corporation.

"farmout" means an agreement whereby a third party agrees to pay for all or a portion of the drilling of a well on one or more of the Properties in order to earn an interest therein, with an Operating Subsidiary retaining a residual interest in such Properties.

"**Gross**" means:

(a) in relation to the Operating Subsidiaries' interest in production and reserves, its "Corporation gross reserves", which are the Operating Subsidiaries' interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Operating Subsidiaries;

(b) in relation to wells, the total number of wells in which the Operating Subsidiaries have an interest; and

(c) in relation to properties, the total area of properties in which the Operating Subsidiaries have an interest.

"HST" means Harvest Sask Energy Trust, a trust established under the laws of the Province of Alberta, wholly owned by the Trust.

"Initial Public Offering" means the initial public offering of 3,750,000 Trust Units at a price of $8.00 per Trust Unit completed on December 5, 2002, resulting in gross proceeds of $30,000,000, and includes the over-allotment option granted in favour of and exercised by the underwriters to acquire an additional 562,500 Trust Units at a price of $8.00 per Trust Unit, resulting in gross proceeds of $4,500,000.

"Interim Bank Facility" means the interim credit facility provided by the Interim Lender as more fully described under "Information Respecting the Corporation – Borrowing by the Corporation", which interim credit facility was replaced with the Current Bank Facility.

"Interim Lender" means the Canadian chartered bank providing the Interim Bank Facility.

"Management Group" means those directors and officers of the Corporation and their family members, close friends and business associates who owned the Management Group Debentures. See "Risk Factors – Public and Insider Ownership".

"Management Group Debentures" means debentures of 990148 Alberta Ltd. previously held by the Management Group. See "Risk Factors – Public and Insider Ownership".

"McDaniel" means McDaniel & Associates Consultants Ltd., independent oil and natural gas reservoir engineers of Calgary, Alberta.

"McDaniel Report" means the report of McDaniel dated April 1, 2004 evaluating the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries as at December 31, 2003.

"**Net**" means:

(a) in relation to the Operating Subsidiaries' interest in production and reserves, the Operating Subsidiaries' interest (operating and non-operating) share after deduction of royalties obligations, plus the Operating Subsidiaries' royalty interest in production or reserves.

(b) in relation to wells, the number of wells obtained by aggregating the Operating Subsidiaries' working interest in each of its gross wells; and

(c) in relation to the Operating Subsidiaries' interest in a property, the total area in which the Operating Subsidiaries have an interest multiplied by the working interest owned by the Operating Subsidiaries.

"**NI 51-101**" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities;

"Notes" means, collectively, the promissory notes issuable by the Corporation in series pursuant to a note indenture to be redeemed in consideration for a portion of the NPI, having a fair market value equal to such principal amount, and being subject to the following terms and conditions:

(a) being unsecured and bearing interest at 6% per annum payable monthly in arrears on the 20th day of the next following month;

(b) being 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 the Corporation or any subsidiary of the Corporation or the Trust on any creditor proceedings such as bankruptcy, liquidation or insolvency;

(c) being subject to earlier prepayment, being due and payable on the 15th anniversary of the date of issuance;

(d) being an aggregate principal amount not to exceed $500 million, and

(e) being subject to such other standard terms and conditions as would be included in a note indenture for promissory notes of this kind, as may be approved by the Harvest Board.

"NPI" means, collectively, the net profit interest owing by the Operating Subsidiaries to the Trust pursuant to the NPI Agreements.

"NPI Agreements" means, collectively, the amended and restated net profit interest agreement dated September 27, 2002 between the Corporation and the Trust, the royalty agreement dated effective January 17, 2003 between WEI and BNY Trust Company of Canada and the net profit interest agreement dated October 17, 2003 between HST and the Trust and **"NPI Agreement"** means any one of these agreements, as applicable.

"NYMEX" means the New York Mercantile Exchange.

"Operating Subsidiaries" means, collectively, the Corporation and HST, each a wholly-owned subsidiary of the Trust, and **"Operating Subsidiary"** means either of the Corporation or HST, as applicable.

"Ordinary Resolution" means a resolution approved at a meeting of Unitholders by more than 50% of the votes cast in respect of the resolution by or on behalf of Unitholders present in person or represented by proxy at the meeting.

"**Permitted Investments**" means:

(a) loan advances to the Corporation;

(b) interest bearing accounts of certain financial institutions including Canadian chartered banks and the Trustee;

(c) obligations issued or guaranteed by the Government of Canada or any province of Canada or any agency or instrumentality thereof;

(d) term deposits, guaranteed investment certificates of deposit or bankers' acceptances of or guaranteed or accepted by any Canadian chartered bank or other financial institution (including the Trustee and any Affiliate of the Trustee) the short term debt or deposits of which have been rated at least A or the equivalent by Standard & Poor's Corporation or Moody's Investors Service, Inc. or Dominion Bond Rating Service Limited;

(e) commercial paper rated at least A or the equivalent by Dominion Bond Rating Service Limited; and

(f) investments in bodies corporate, partnerships or trusts engaged in the oil and natural gas business;

provided that an investment is not a Permitted Investment if it:

(g) would result in the cost amount to the Trust of all "foreign property" (as defined in the Tax Act) which is held by the Trust to exceed the amount prescribed by Regulation 5000(1) of the Regulations to the Tax Act;

(h) is a "small business security" as that term is used in Part L1 of the Regulations to the Tax Act; or

(i) would result in the Trust not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

"Person" includes an individual, a body corporate, a trust, a union, a pension fund, a government and a governmental agency.

"Prior Bank Facility" means the credit facility provided by the Prior Lender to the Corporation which was repaid in full on September 30, 2003.

"Prior Lender" means a syndicate of lenders with a U.S. bank as a lender and as administrative agent for all of the lenders.

"Pro Rata Share" means, of any particular amount in respect of a Unitholder at any time, the product obtained by multiplying the number of Trust Units that are owned by that Unitholder at that time by the quotient obtained when the particular amount is divided by the total number of all Trust Units that are issued and outstanding at that time.

"Production" means the produced petroleum, natural gas and natural gas liquids attributed to the Properties.

"**Properties**" means the working, royalty or other interests of the Corporation and HST in any petroleum and natural gas rights, tangibles and miscellaneous interests, including properties which may be acquired by the Corporation or HST from time to time.

"Property Interests" means petroleum and natural gas rights and related tangibles and miscellaneous interests beneficially owned by the Corporation or HST.

"Provost Properties" means Properties other than the Carlyle Properties.

"Provost Properties Vendors" means, collectively, the vendors from whom the Operating Subsidiaries acquired the Provost Properties.

"Record Date" means December 31 of each year hereafter and the last day of each calendar month or such other date as may be determined from time to time by the Trustee upon the recommendation of the Board of Directors.

"Reserve Fund" means the cumulative amount of production and other revenues entitled to be retained by the Operating Subsidiaries pursuant to the NPI Agreements to provide for payment of production costs which the Operating Subsidiaries estimate will or may become payable in the following six months for which there may not be sufficient production revenues to satisfy such production costs in a timely manner. See "Description of the Trust – The NPI and Direct Royalties – Reserve Fund".

"Reserve Life Index" or **"RLI"** means the amount obtained by dividing the quantity of proved plus probable reserves as at December 31, 2003, by the annualized 2004 production of petroleum, natural gas and natural gas liquids from those reserves as projected in the McDaniel Report.

"Reserve Value" means, for any petroleum and natural gas property at any time, the present worth of all of the estimated pre-tax cash flow net of capital expenditures from the proved plus probable reserves shown in the

McDaniel Report for such property, discounted at 10% and using forecast price and cost assumptions (a common benchmark in the oil and natural gas industry).

"Senior Indebtedness" means all indebtedness, liabilities and obligations of the Trust (whether outstanding as at the date of the Indenture or thereafter created, incurred or assumed or for which it is liable in respect of any guarantee, indemnity, suretyship or joint and several liability) (i) in respect of borrowed money of itself or any subsidiary; (ii) in connection with the acquisition of any business, properties or asset by itself or any subsidiary; (iii) in connection with risk mitigation instruments or agreements of itself or a subsidiary; (iv) to any trade creditors of itself or any subsidiary; or (v) renewals, extensions, restructurings, refinancings and refunding of any of the foregoing; unless the instrument creating or evidencing any of the foregoing provides that such indebtedness, liabilities or obligations are to rank *pari passu*, or subordinate, in right of payment to the Debentures.

"Special Resolution" means a resolution proposed to be passed as a special resolution at a meeting of Unitholders (including an adjourned meeting) duly convened for the purpose and held in accordance with the provisions of the Trust Indenture at which two or more holders of at least 10% of the aggregate number of Trust Units then outstanding are present in person or by proxy and passed by the affirmative votes of the holders of not less than 66 2/3% of the Trust Units represented at the meeting and voted on a poll upon such resolution.

"Special Warrants" means the special trust unit purchase warrants sold to a syndicate of underwriters on February 4, 2003, which warrants were exchanged for Trust Units upon their deemed exercise on March 7, 2003.

"Storm" means Storm Energy Limited.

"Subsequent Investments" means any of the investments that the Trust may make pursuant to the Trust Indenture, which includes:

(a) making payments to the Corporation pursuant to the Deferred Purchase Price Obligations under the NPI Agreement;

(b) making loans to the Corporation in connection with the Capital Fund; and

(c) temporarily holding cash and investments for the purposes of paying the expenses and liabilities of the Trust, making certain other investments as contemplated by Section 4.2 of the Trust Indenture, paying amounts payable to the Trust in connection with the redemption of any Trust Units, and making distributions to Unitholders;

provided that such investments will not be a Subsequent Investment if it:

(d) would result in the cost amount to the Trust of all "foreign property" (as defined in the Tax Act) which is held by the Trust to exceed the amount prescribed by Regulation 5000(1) of the Regulations to the Tax Act;

(e) is a "small business security" as that term is used in Part L1 of the Regulations to the Tax Act; or

(f) would result in the Trust not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

"Tax Act" means the *Income Tax Act* (Canada) and the regulations thereunder.

"Trust" or **"Harvest"** means Harvest Energy Trust.

"Trust Fund" at any time, shall mean any of the following monies, properties and assets that are at such time held by the Trustee on behalf of the Trust for the purposes of the Trust under the Trust Indenture:

(a) the amount paid to settle the Trust;

(b) all funds realized from the issuance of Trust Units;

(c) any Permitted Investments in which funds may from time to time be invested;

(d) all rights in respect of and income generated under the NPI Agreement with the Corporation, including the applicable NPI;

(e) all rights in respect of and income generated under a Direct Royalties Sale Agreement;

(f) any Subsequent Investment;

(g) any proceeds of disposition of any of the foregoing property including, without limitation, the Direct Royalties; and

(h) all income, interest, profit, gains and accretions and additional assets, rights and benefits of any kind or nature whatsoever arising directly or indirectly from or in connection with or accruing to such foregoing property or such proceeds of disposition.

"Trust Indenture" means the amended and restated trust indenture dated July 10, 2003 between the Trustee and the Corporation as such indenture may be further amended by supplemental indentures from time to time.

"Trust Unit" means a trust unit of the Trust created, issued and certified under the Trust Indenture and outstanding and entitled to the benefits thereof.

"Trustee" means Valiant Trust Company, or its successor as trustee of the Trust.

"TSX" means the Toronto Stock Exchange.

"Unitholders" means the holders from time to time of one or more Trust Units.

"Unit Incentive Plan" means the Trust's unit incentive plan described under "Trust Unit Incentive Plan".

"U.S. Securities Act" means the *United States Securities Act of 1933*, as amended.

"WEI" means the Trust's former wholly-owned subsidiary, Westcastle Energy Inc., a corporation incorporated under the *Business Corporations Act* (Alberta) and which amalgamated with the Corporation on January 1, 2004, with the amalgamated corporation continuing under the name "Harvest Operations Corp.".

"Working Interest" or **"WI"** means an undivided interest held by a party in an oil and/or natural gas or mineral lease granted by a Crown or freehold mineral owner, which interest gives the holder the right to "work" the property (lease) to explore for, develop, produce and market the lease substances but does not include, among other things, a royalty, overriding royalty, gross overriding royalty, net profits interest or other interest that entitles the holder thereof to a share of production or proceeds of sale of production without a corresponding right or obligation to "work" the property.

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.

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	Barrel
Bbls	Barrels
Mbbls	thousand barrels
Bbls/d	barrels per day
Mmbbls	million barrels
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
Mmcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
MMBTU	million British Thermal Units

Other

AECO	EnCana Corporation's natural gas storage facility located at Suffield, Alberta.
BOE	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one Bbl of oil, unless otherwise specified. The conversion factor used to convert natural gas to oil equivalent is not necessarily based upon either energy or price equivalents at this time.
BOE/d	barrels of oil equivalent per day.
MBOE	means thousand barrels of oil equivalent.
MMBOE	means million barrels of oil equivalent.
OOIP	means original oil in place.
WTI	means West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.
ºAPI	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
MW	megawatts of electrical power.
3D	three dimensional.
Darcies	means the measure of permeability (being the ease with which a single fluid will flow through connected pore space when a pressure gradient is applied).
porosity	means the measure of the fraction of pore space of a reservoir.
$000	thousands of dollars
$millions	millions of dollars

CONVERSIONS

The following table sets forth certain 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
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

ALL DOLLAR AMOUNTS SET FORTH IN THIS ANNUAL INFORMATION FORM ARE IN CANADIAN DOLLARS, EXCEPT WHERE OTHERWISE INDICATED.

DATE OF INFORMATION

Unless otherwise specified, information in this Annual Information Form is as at the end of the Trust's most recently completed financial year, being December 31, 2003.

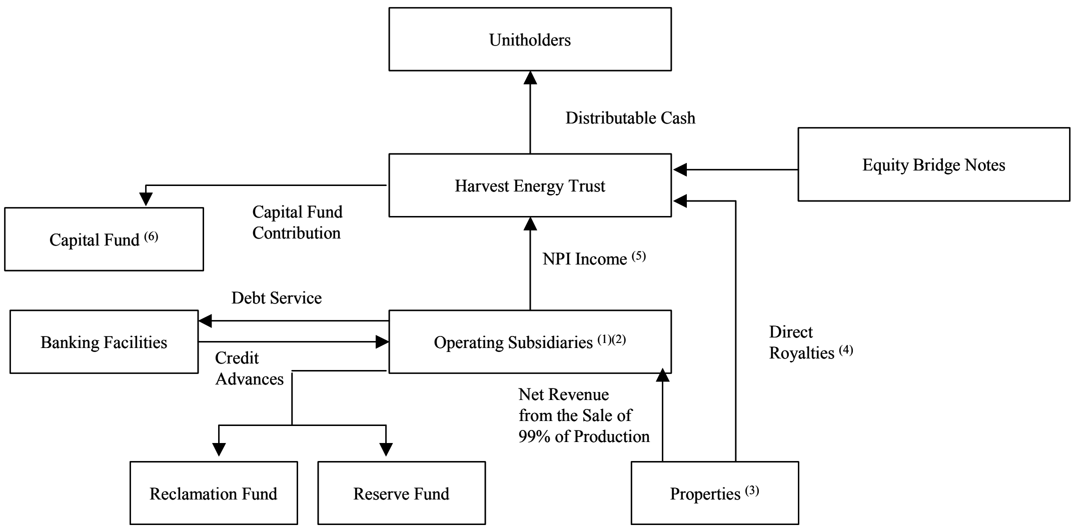
HARVEST ENERGY TRUST

General

The Trust is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta and created pursuant to the Trust Indenture. The head and principal office of the Trust is located at Suite 1900, 330 - 5th Avenue S.W., Calgary, Alberta T2P 0L4. Although the Trust receives income from the NPI from each of the Operating Subsidiaries, all oil and natural gas operations are conducted through the Corporation and the Trust is managed solely by the Corporation pursuant to the Trust Indenture and the Administration Agreement.

Structure of the Trust

The structure of the Trust and the flow of cash from the Properties to the Operating Subsidiaries, from the Operating Subsidiaries to the Trust and from the Trust to Unitholders are set forth below:



Notes:

(1) As of January 1, 2004, the Operating Subsidiaries consist of Harvest Operations Corp. and Harvest Sask Energy Trust, each of which is a wholly-owned subsidiary of the Trust.

(2) Although the Trust receives NPI income from each of the Operating Subsidiaries, all operations and management of the Trust are conducted through the Corporation.

(3) The Operating Subsidiaries own the Properties.

(4) In addition to the NPI, the Trust holds various Direct Royalties.

(5) The Trust receives regular monthly payments in accordance with the NPI Agreements. See "Description of the Trust – The NPI and Direct Royalties".

(6) The Trust may retain up to 50% of the Cash Available For Distribution in its Capital Fund to finance future acquisitions and development of the Properties.

General Development of the Business

The following is a description of the general development of the business of the Trust.

The Corporation was incorporated on May 14, 2002 to carry on oil and natural gas acquisition, development and production activities. The Board of Directors then reviewed its strategic alternatives and based on such review determined that the formation of an energy royalty trust was the optimal structure. On July 10, 2002, the Trust was formed pursuant to the Trust Indenture. On the same date, the Corporation and the Trust entered into a net profit agreement which has been amended and restated effective September 27, 2002 pursuant to which the Corporation granted to the Trust the right to receive income from the net profit interest created thereby on Properties held by the Corporation from time to time. Pursuant to that NPI Agreement, the Trust paid to the Corporation $12.6 million using the proceeds from an interim loan provided by Caribou to the Trust.

On July 10, 2002 the Corporation acquired certain direct royalties and properties from a major oil and natural gas producer for an aggregate purchase price of $26.1 million. The acquisition consisted of an overriding royalty interest of 7.10688% in the Choice Viking Gas Unit No. 1, and an approximate 99% working interest in oil and natural gas producing properties that are both unitized and non-unitized. The purchase price was funded by an advance under the Corporation's credit facilities and, indirectly, through an interim loan provided by Caribou to the Trust.

On August 1, 2002 the Corporation entered into an Agreement of Purchase and Sale with a major oil and natural gas producer to purchase certain direct royalties and properties effective June 1, 2002 for an aggregate purchase price of $71.8 million. The Corporation completed the acquisition on November 15, 2002 for a closing price of $53.2 million. The acquisition consisted of a direct royalty interest and an interest in oil and natural gas producing properties located in East Central Alberta. The purchase price was funded by an advance under the Corporation's credit facilities and, indirectly, through an interim loan provided by Caribou to the Trust.

On December 5, 2002, the Trust completed the Initial Public Offering, which resulted in the issuance of 3,750,000 Trust Units and aggregate gross proceeds of $30.0 million. Approximately $22.9 million from the net proceeds of the Initial Public Offering was used to repay interim loans which had been provided by Caribou to the Trust (including accrued interest) and approximately $5.4 million from the net proceeds of the Initial Public Offering was used to partially repay bank indebtedness. The balance was used for general working capital purposes.

On December 17, 2002, the Trust issued 562,500 Trust Units to FirstEnergy Capital Corp. and Haywood Securities Inc. as a result of the exercise of an over-allotment option granted to them in connection with the Initial Public Offering. The gross proceeds from the sale of such Trust Units were $4.5 million.

On February 4, 2003, the Trust sold 1,500,000 Special Warrants to a syndicate of underwriters at a price of $10.00 per Special Warrant for net proceeds of $13.7 million. Each Special Warrant entitled the holder to receive on exercise or deemed exercise one Trust Unit for the payment of no additional consideration. On March 7, 2003, the Trust received receipts for a (final) prospectus qualifying the Trust Units issuable on exercise of the Special Warrants and on March 7, 2003, the Trust issued 1,500,000 Trust Units on the deemed exercise of the Special Warrants. The net proceeds were used to partially repay bank indebtedness and for working capital.

During April and May, 2003, the Corporation closed the acquisition of various interests in two properties in the Killarney area of Alberta. The properties were acquired from two major oil and natural gas producers for $13.2 million and the issuance of 200,000 Trust Units respectively. The cash acquisition was financed through the Corporation's credit facilities. Included with the acquisition was an interest in two oil batteries.

At the Annual and Special Meeting of Unitholders of the Trust held on June 12, 2003 (the "2003 Unitholders' Meeting"), Unitholders approved resolutions respecting each of the matters set forth below:

- to amend the Trust Indenture to authorize the creation of an unlimited number of special voting units ("Special Voting Units"). Each Special Voting Unit entitles the holder thereof to such number of votes at meetings of Unitholders as may be prescribed by the Board of Directors of the Corporation in the resolution authorizing the issuance of any such Special Voting Units;

- to amend the Trust Indenture to grant the Corporation (through the Board of Directors) the specific authority and responsibility for any and all matters relating to the terms of the NPI Agreement and other material contracts of the Trust (other than as otherwise provided in the Trust Indenture) including any amendments thereto;

- to amend the Trust Indenture to clarify and elaborate upon the responsibility which had previously been delegated to the Corporation in respect of matters relating to an issuance or offering of Trust Units or any other rights, warrants or other securities to purchase, to convert into or to exchange into Trust Units;

- to authorize an amendment of the articles of the Corporation to create a new class of non-voting common shares, issuable in series ("Non-Voting Shares"). Except for the right to notice of and to attend at any meetings of the shareholders of the Corporation, the holder of the Non-Voting Shares will have the same rights as the holders of common shares of the Corporation;

- to increase the number of Trust Units which may be reserved for issuance under the Unit Incentive Plan by 246,000 Trust Units from 875,000 Trust Units to a cumulative maximum number of 1,121,000 Trust Units; and

- approving the issuance by the Trust in one or more private placements during the 12 month period commencing June 12, 2003, of up to 11,210,957 Trust Units, subject to certain restrictions.

On June 27, 2003, the Trust completed the acquisition of all of the common shares of WEI and an NPI in certain producing oil and natural gas properties held by WEI in exchange for total consideration of approximately $10.1 million (consisting of the issuance of 625,000 Trust Units, $3 million in cash and a $850,000 unsecured promissory note) plus the assumption of $2.8 million in bank debt and $2.3 million in working capital deficit. The oil and natural gas producing properties acquired included working interests ranging from 20% to 100% in the fields of Amisk, Czar and Killarney, all of which are operated by the Corporation.

On July 28, 2003, the Trust entered into the Equity Bridge Notes to provide funds to pay the Deferred Purchase Price Obligation associated with the Carlyle Properties Transaction. On July 29, 2003, $11 million was advanced to the Trust pursuant to the Equity Bridge Notes to fund a deposit relating to the purchase of the Carlyle Properties. On September 29, 2003, the Trust amended the Equity Bridge Notes to allow advances to be used to pay out the Corporation's then existing credit facility and entered into the Bridge Notes. On September 29, 2003, the Trust received additional advances under the Equity Bridge Notes in the amount of $22.5 million and also received advances of $25.0 million under the Bridge Notes. These amounts were advanced by the Trust to the Corporation on September 30, 2003 and used to pay out in part the approximately $48.1 million owing under the Corporation's then existing credit facility. On October 1, 2003, the $11 million deposit in connection with the Carlyle Properties Transaction was refunded and the Trust used this amount to repay $11 million of principal in respect of the Bridge Notes.

On July 29, 2003 the Corporation entered into an agreement in respect of the purchase of partnership interests in a New Brunswick limited partnership which held the Carlyle Properties. On September 29, 2003 the Corporation entered into an agreement wherein the interests of the Corporation in the July 29, 2003 agreement referred to above were assigned to the Carlyle Properties Vendor and wherein it was agreed that substantially all of the Carlyle Properties would be conveyed to the Corporation. On October 1, 2003, the Corporation entered into the Carlyle Properties Acquisition Agreement with the Carlyle Properties Vendor to acquire substantially all of the Carlyle Properties effective October 1, 2003 for total consideration of approximately $80 million, prior to adjustments and transaction costs. Closing of the Carlyle Properties Acquisition occurred on October 16, 2003.

Immediately following the completion of the Carlyle Properties Transaction, the Trust completed an internal reorganization pursuant to which substantially all of the Carlyle Properties were conveyed to HST, a trust which is wholly-owned by the Trust.

The Carlyle Properties Acquisition was financed as to $48.65 million through an offering of 4,312,500 Trust Units at a price of $12.00 per Trust Unit for gross proceeds of $51.8 million and as to $31.35 million through advances under the Current Bank Facility.

The Carlyle Properties are located in South East Saskatchewan near the town of Carlyle. The majority of the production is situated between Township 7 Range 32 W1M to Township 13 Range 13 W2M. For the month of September 2003, the Carlyle Properties produced approximately 5,200 BOE/d of light (28° to 34° API) oil concentrated in the Mississippian-aged Tilson subcrop play trend. As evaluated by McDaniel in the McDaniel Report, the Carlyle Properties contained, as at December 31, 2003, 14.0 MMBOE of proved plus probable reserves, with an RLI of 8.3 years. The recovery mechanism is bottom water drive supported by an active aquifer affording an efficient recovery of reserves, making operating characteristics of the Carlyle Properties similar to those of the other Properties. The Trust acquired an average 98% Working Interest in the Carlyle Properties and assumed operatorship of over approximately 95% of the total production from the properties. All the production is concentrated geographically which promotes ease of access and operating synergies. To support ongoing growth of the properties, management has identified upside value associated with production optimization, development drilling, the undeveloped land holdings and the proprietary seismic database, which are part of the assets associated with the Carlyle Properties.

A schedule of revenue and expenses for the Carlyle Properties for the years ended December 31, 2002, 2001 and 2000 and the nine months ended September 30, 2003 and 2002 are contained in this Annual Information Form. Pro forma financial statements of the Trust for the year ended December 31, 2003 are also contained in this Annual Information Form.

Upon closing of the Carlyle Properties Transaction on October 16, 2003, the Corporation put in place its Current Bank Facility and the Corporation used a portion of this facility to repay $8.5 million of the Equity Bridge Notes and approximately $14 million was used to repay in full the Bridge Notes.

On October 16, 2003, the Trust issued 4,312,500 Trust Units at a price of $12.00 per Trust Unit for gross proceeds of $51.8 million. The Trust Units were offered to the public through a syndicate of underwriters, which was led by National Bank Financial Inc. and included CIBC World Markets Inc., FirstEnergy Capital Corp. and Haywood Securities Inc.

Significant Acquisitions and Significant Dispositions

There were no significant acquisitions or significant dispositions by the Trust or any significant probable acquisition by the Trust within or since the completion of the most recently completed financial year of the Trust other than as described above in "- General Development of the Business" and as described in "Recent Developments – Acquisition of Storm Energy Limited".

Trends

There are a number of trends in the oil and natural gas industry that are shaping the near term future of the business. The first trend is the ongoing consolidation phase that the industry has been going through which has affected companies of all sizes from the small emerging companies to the senior integrated organizations. Although consolidation is nothing new for the industry, the pace at which it has occurred during the past 30 months and the nature of the companies involved are unique. The companies which have been consolidated include the traditional small to medium size companies as well as a number of large, well established companies. The most active acquirors have been royalty trusts and one large Canadian oil and natural gas producer.

Another continuing trend has been small to medium sized exploration and production companies converting to royalty trusts. These new trusts have become active in the consolidation of the industry thereby increasing competition for the previously existing trusts.

Including recently announced conversions of several exploration and production companies to trusts, approximately half of the top 30 publicly listed oil and natural gas issuers on the TSX are now trusts. Annual production declines from the trusts will likely result in a continued high level of competition for available oil and natural gas properties and companies. This increased competition within the trust sector, as well as the influence of U.S. based companies, has resulted in higher valuation parameters for corporate and asset acquisitions. Those trusts with substantial opportunities for production replacement through internal development drilling should be in an advantaged position relative to those more exposed to production replacement through acquisitions.

Another ongoing trend is the continued volatility of oil and natural gas prices with oil and natural gas company capital budgets highly responsive to commodity prices. As the supply/demand balance for both natural gas and crude oil tightens, commodity prices increase and drilling activity rises reflecting increased capital spending by oil and natural gas companies. Conversely, as commodity prices decline, capital budgets are reduced and drilling activity declines. In tight markets such as those the Trust is currently encountering, the supply response resulting from changing drilling activity has a material impact on prices. In addition, oil prices have been stronger due to higher demand associated with growing world economies. This has been supported by the influence of the political instability in the Middle East. Price volatility is expected to be an ongoing characteristic of the oil and natural gas industry.

The Canadian/U.S. exchange rate also influences commodity prices received by Canadian producers as oil and natural gas production is priced in U.S. dollars. The strengthening witnessed in 2003 of the Canadian dollar has had a negative impact on Canadian oil and natural gas production revenue. The recent weakening trend for the Canadian dollar has served to improve Canadian dollar revenue from oil and natural gas sales.

RECENT DEVELOPMENTS

Amalgamation of Subsidiaries

On January 1, 2004 WEI amalgamated with Harvest Operations Corp. and the amalgamated corporation continued under the name "Harvest Operations Corp.".

Issue of Debentures

On January 29, 2004, the Trust issued $60 million principal amount of Debentures. The Debentures were offered to the public through a syndicate of underwriters which was led by National Bank Financial Inc. and included CIBC World Markets Inc., FirstEnergy Capital Corp., Haywood Securities Inc., TD Securities Inc. and Canaccord Capital Corporation.

On March 15, 2004, 1,000 convertible debentures were converted at the option of the holder, into 71,428 trust units and $11 for accrued interest and fractional units.

Acquisition of Storm Energy Limited

On April 19, 2004, the Trust announced that it had entered into an agreement with Storm to effect a business combination through a Plan of Arrangement whereby the Trust will acquire all of the outstanding shares of Storm for approximately $189 million, including assumed net debt of approximately $64 million. The proposed transaction contemplates the Trust and Storm combining their assets into the Trust and transferring certain of Storm's assets into a separate junior exploration and development company whose shares will be held by the former shareholders of Storm ("ExploreCo"). The properties to be acquired produce approximately 4,200 BOE per day and are primarily concentrated in the Red Earth area of north central Alberta. The consideration to be paid by the Trust to each shareholder of Storm will be $4.15 per share in cash to a maximum aggregate cash amount of $75 million; or 0.281 of an exchangeable share of the Corporation, exchangeable into Trust Units, to a maximum aggregate of 2 million exchangeable shares; or 0.281 of a Trust Unit, to a maximum aggregate of 8 million units and exchangeable shares combined. In addition, each Storm shareholder will receive one common share of ExploreCo and approximately 0.053 common shares of Rock Energy Inc., a company which Storm presently has an interest in.

Shareholders of Storm will be asked to approve the transaction at a special meeting of shareholders to be held in June 2004. If Storm shareholder approval is obtained and all other conditions are satisfied, it is anticipated that the transaction will close in late June 2004.

Potential Acquisitions

The Trust continues to evaluate potential acquisitions of all types of petroleum and natural gas and other energy-related assets as part of its ongoing acquisition program. The Trust is normally in the process of evaluating several potential acquisitions at any one time which individually or together could be material. As of the date hereof, the Trust has not reached agreement on the price or terms of any potential material acquisitions other than as described above under "- Acquisition of Storm Energy Limited". The Trust cannot predict whether any current or future opportunities will result in one or more acquisitions for the Trust.

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below (the "Statement") is dated April 30, 2004. The effective date of the Statement is December 31, 2003 and the preparation date of the Statement is April 1, 2004.

Disclosure of Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by McDaniel with an effective date of December 31, 2003 contained in the McDaniel Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional 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 Operating Subsidiaries engaged McDaniel to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Operating Subsidiaries' reserves are in Canada and, specifically, in the provinces of Alberta and Saskatchewan.

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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 Operating Subsidiaries' 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.

Reserves Data (Constant Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2003
CONSTANT PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED								
Developed Producing	20,985	19,088	7,501	6,327	2,080	1,779	127	107
Developed Non-Producing	26	25	-	-	6.6	4.6	0.4	0.3
Undeveloped	1,100	1,000	275.5	205.3	74	67	8	7
TOTAL PROVED	22,111	20,114	7,776	6,532	2,161	1,850	136	114
PROBABLE	5,446	5,044	1,475	1,247	784	625	35	30
TOTAL PROVED PLUS PROBABLE	27,557	25,158	9,252	7,779	2,945	2,475	171	144

	NET PRESENT VALUES OF FUTURE NET REVENUE DISCOUNTED BEFORE INCOME TAXES [(1)]				
RESERVES CATEGORY	0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
PROVED					
Developed Producing	296,004	265,461	234,732	209,207	188,627
Developed Non-Producing	99	145	158	157	150
Undeveloped	17,170	12,602	9,371	7,025	5,278
TOTAL PROVED	313,274	278,208	244,262	216,390	194,055
PROBABLE	74,945	50,462	35,962	26,690	20,433
TOTAL PROVED PLUS PROBABLE	388,219	328,671	280,225	243,080	214,489

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

RESERVES CATEGORY	REVENUE ($000)	ROYALTIES ($000)	OPERATING COSTS ($000)	DEVELOPMENT COSTS ($000)	WELL ABANDONMENT COSTS ($000)	FUTURE NET REVENUE BEFORE INCOME TAXES(1) ($000)
Proved Reserves	954,753	122,051	465,088	15,248	39,090	313,274
Proved Plus Probable Reserves	1,179,052	143,625	576,505	30,972	39,729	388,219

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) ($000)
Proved Reserves	Light and Medium Crude Oil	196,748
	Heavy Crude Oil	38,607
	Natural Gas (including by-products)	8,908
Proved Plus Probable Reserves	Light and Medium Crude Oil	227,814
	Heavy Crude Oil	41,067
	Natural Gas (including by-products)	11,344

Reserves Data (Forecast Prices and Costs) – December 31, 2003

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2003
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED								
Developed Producing	18,201.5	16,557.8	7,235.7	6,101.9	1,909.9	1,630.2	114.5	95.0
Developed Non-Producing	17.5	17.0	-	-	4.5	3.1	0.3	0.2
Undeveloped	1,032.6	937.3	275.5	205.3	73.8	67.1	7.4	6.6
TOTAL PROVED	19,251.6	17,512.1	7,511.3	6,307.1	1,988.2	1,700.5	122.1	101.8
PROBABLE	4,617.5	4,279.7	1,052.9	895.6	710.8	564.1	31.6	27.2
TOTAL PROVED PLUS PROBABLE	23,869.1	21,791.8	8,564.2	7,202.7	2,699.0	2,264.6	153.6	129.0

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) [1]				
RESERVES CATEGORY	0 ($000)	5 ($000)	10 ($000)	15 ($000)	20 ($000)
PROVED					
Developed Producing	171,659	161,319	149,533	138,481	128,691
Developed Non-Producing	(89)	(28)	8	28	38
Undeveloped	10,585	7,586	5,381	3,743	2,506
TOTAL PROVED	182,155	168,878	154,922	142,252	131,235
PROBABLE	26,267	19,372	14,249	10,572	7,916
TOTAL PROVED PLUS PROBABLE	208,422	188,250	169,171	152,824	139,152

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

RESERVES CATEGORY	REVENUE ($000)	ROYALTIES ($000)	OPERATING COSTS ($000)	DEVELOPMENT COSTS ($000)	WELL ABANDONMENT COSTS ($000)	FUTURE NET REVENUE BEFORE INCOME TAXES[1] ($000)
Proved Reserves	746,372	98,174	400,807	15,476	49,758	182,155
Proved Plus Probable Reserves	909,733	113,674	504,668	31,706	51,262	208,422

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) ($000)
Proved Reserves	Light and Medium Crude Oil	118,218
	Heavy Crude Oil	29,263
	Natural Gas (including by-products)	7,440
Proved Plus Probable Reserves	Light and Medium Crude Oil	130,361
	Heavy Crude Oil	29,510
	Natural Gas (including by-products)	9,299

Notes to Reserves Data Tables:

1. The Trust is entitled to deduct from its income all amounts which are paid or payable by it to Unitholders in a given financial year. As a result of amounts paid to Unitholders in the course of the most recent financial year, the Trust is not liable for any material amount of income tax on income. The net present values of future net revenue after income taxes are, therefore, the same as the net present values of future net revenue before income taxes.

2. Columns may not add due to rounding.

3. The crude oil, natural gas liquids and natural gas reserve estimates presented in the McDaniel Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are 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 (see the discussion of "Economic Assumptions" below).

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

(a) **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.

(b) **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:

(c) **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 certainly.

(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.

(d) **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.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

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.

4. **Forecast Prices and Costs – January 1, 2004**

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 Operating Subsidiaries 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. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the McDaniel Report, which were McDaniel's then current forecasts at the date of the McDaniel Report, were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of January 1, 2004
FORECAST PRICES AND COSTS

	OIL							
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Light Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Bow River Medium 29.3° API ($Cdn/bbl)	NATURAL GAS AECO Gas Price ($Cdn/MMBtu)	NATURAL GAS LIQUIDS FOB Field Gate ($Cdn/BBL)	INFLATION RATES(1) (%/Year)	EXCHANGE RATE(2) ($US/$Cdn)
Forecast								
2004	29.00	37.70	22.70	27.70	5.50	27.90	2.00	0.75
2005	26.50	34.30	21.55	26.65	5.19	25.50	2.00	0.75
2006	25.50	33.00	21.56	26.24	4.87	24.50	2.00	0.75
2007	25.00	32.30	20.63	25.40	4.68	23.80	2.00	0.75
2008	25.00	32.30	20.39	25.26	4.53	23.70	2.00	0.75
2009	25.50	32.90	20.76	25.72	4.57	24.10	2.00	0.75
2010	26.00	33.50	21.11	26.18	4.60	24.50	2.00	0.75
2011	26.50	34.20	21.56	26.73	4.69	25.00	2.00	0.75
2012	27.00	34.80	21.91	27.18	4.78	25.40	2.00	0.75
2013	27.50	35.50	22.35	27.73	4.87	26.00	2.00	0.75
2014	28.10	36.20	22.79	28.28	4.97	26.50	2.00	0.75
2015	28.70	37.00	23.32	28.92	5.08	27.10	2.00	0.75
2016	29.30	37.80	23.85	29.56	5.19	27.60	2.00	0.75
2017	29.90	38.60	24.37	30.19	5.29	28.20	2.00	0.75
2018	30.50	39.30	24.79	30.72	5.40	28.70	2.00	0.75
2019	31.10	40.10	25.30	31.35	5.51	29.30	2.00	0.75
2020	31.70	40.90	25.80	31.98	5.61	29.90	2.00	0.75
2021	32.30	41.70	26.30	32.60	5.72	30.50	2.00	0.75
2022	32.90	42.40	26.69	33.12	5.82	31.00	2.00	0.75
2023	33.60	43.30	27.28	33.83	5.95	31.60	2.00	0.75
Thereafter	33.60	43.30	27.28	33.83	5.95	31.60	0	0.75

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Operating Subsidiaries for the year ended December 31, 2003, were $6.70/mcf for natural gas, $29.92/bbl for natural gas liquids and $27.34/bld for heavy oil.

5. **Constant Prices and Costs**

Constant prices and costs are:

(a) the Operating Subsidiaries' prices and costs as at the effective date of the estimation, 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 Operating Subsidiaries 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 Operating Subsidiaries' prices are the posted prices for oil and the spot price for natural gas, after historical adjustments for transportation, gravity and other factors.

The constant crude oil and natural gas benchmark references pricing and the exchange rate utilized in the McDaniel Report were as follows:

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2003
CONSTANT PRICES AND COSTS

Year	OIL WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	NATURAL GAS AECO Gas Price ($Cdn/MMBtu)	NATURAL GAS LIQUIDS FOB Field Gate ($Cdn/BBL)	EXCHANGE RATE[2] ($US/$Cdn)
Historical 2003[1]	32.78	39.76	22.75	34.25	5.87	31.50	0.75

Notes:
(1) Prices as at December 31, 2003
(2) The exchange rate used to generate the benchmark reference prices in this table.

6. **Future Development Costs**

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

Year	Forecast Prices and Costs ($000) Proved Reserves	Forecast Prices and Costs ($000) Proved Plus Probable Reserves	Constant Prices and Costs ($000) Proved Reserves
2004	11,600	16,583	11,522
2005	3,876	11,923	3,726
2006	0	3,199	0
Thereafter	0	0	0
Total Undiscounted	15,476	31,706	15,248
Total Discounted at 10%	14,420	28,666	14,215

7. Estimated future abandonment and reclamation costs related to a property have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for reclamation of wellsites or the abandonment and reclamation of any facilities.

8. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

9. The extent and character of all factual data supplied to McDaniel were accepted by McDaniel as represented. No field inspection was conducted.

Reconciliations of Changes in Reserves and Future Net Revenue

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

	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED NATURAL GAS		
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)
December 31, 2002	4,258	235	4,493	5,930	528	6,458	1,435	120	1,555
Extensions	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	589	108	698	-	-	-
Technical Revisions	579	940	1,519	1,181	212	1,392	(91)	387	296
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	14,330	3,105	17,435	284	49	333	760	57	817
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(1,655)	-	(1,655)	(1,677)	-	(1,677)	(403)	-	(403)
December 31, 2003	17,512	4,280	21,792	6,307	896	7,203	1,701	564	2,265

Note:

(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 Operating Subsidiaries 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 Operating Subsidiaries.

(2) Natural gas liquids reserves have not been reconciled as they represent less than 0.05% of total reserves.

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

PERIOD AND FACTOR	2003 ($000)
Estimated Future Net Revenue at Beginning of Year	203,914
Sales and Transfers of Oil and Natural Gas Produced, Net of Production Costs and Royalties	(84,015)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(73,792)
Development Costs During the Period	17,630
Changes in Forecast Development Costs	(13,365)
Extensions and Improved Recovery	7,403
Discoveries	-
Acquisitions of Reserves	150,860
Dispositions of Reserves	-
Net Change Resulting from Revisions in Quantity Estimates	15,237
Accretion of Discount	20,391
Net Change in Income Taxes	-
Estimated Future Net Revenue at End of Year	244,263

Reserves Information – Updated Pricing

The information set forth below is based upon an evaluation by McDaniel with an effective date of December 31, 2003. Such reserves information summarizes the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries and the net present values of future net revenue for these reserves using McDaniel's April 1, 2004, forecast prices and costs (rather than McDaniel's forecasts as at January 1, 2004, as described above under "Disclosure of Reserves Data".

The reserves information presented below is in addition to the detailed information respecting the Operating Subsidiaries and their reserves which has been prepared as required under NI 51-101. In particular, the forecast prices and costs which have been utilized in the McDaniel evaluation upon which the reserves information presented below is based were McDaniel's forecasts as at April 1, 2004, rather than McDaniel's forecasts as at January 1, 2004:

Reserves Data (Forecast Prices and Costs) – April 1, 2004

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of April 1, 2004
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED								
Developed Producing	18,396	16,711	7,251	6,112	1,919	1,638	115	95
Developed Non-Producing	18	17	-	-	4	3	-	-
Undeveloped	1,040	944	275	205	74	67	7	6
TOTAL PROVED	19,454	17,673	7,526	6,317	1,997	1,708	123	102
PROBABLE	4,873	4,516	1,037	882	724	575	32	28
TOTAL PROVED PLUS PROBABLE	24,328	22,189	8,564	7,199	2,722	2,284	155	130

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) (1)				
RESERVES CATEGORY	0 ($000)	5 ($000)	10 ($000)	15 ($000)	20 ($000)
PROVED					
Developed Producing	225,615	211,189	196,023	182,191	170,080
Developed Non-Producing	(682)	(517)	(407)	(332)	(279)
Undeveloped	12,548	9,314	6,930	5,153	3,806
TOTAL PROVED	237,481	219,985	202,546	187,012	173,607
PROBABLE	33,207	24,812	18,728	14,409	11,299
TOTAL PROVED PLUS PROBABLE	270,689	244,798	221,275	201,421	184,907

Forecast Prices and Costs – April 1, 2004

Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by McDaniel, which were McDaniel's forecasts as at April 1, 2004, were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of April 1, 2004
FORECAST PRICES AND COSTS

	OIL							
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Light Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Bow River Medium 29.3° API ($Cdn/bbl)	NATURAL GAS AECO Gas Price ($Cdn/MMBtu)	NATURAL GAS LIQUIDS FOB Field Gate ($Cdn/BBL)	INFLATION RATES(1) (%/Year)	EXCHANGE RATE(2) ($US/$Cdn)
Forecast								
2004(3)	34.00	44.30	29.30	34.30	6.05	32.40	2.00	0.75
2005	29.00	37.60	24.90	30.00	5.65	28.00	2.00	0.75
2006	27.00	35.00	23.60	28.20	5.10	25.90	2.00	0.75
2007	25.50	32.90	21.20	26.00	4.80	24.30	2.00	0.75
2008	25.50	32.90	21.00	25.90	4.70	24.20	2.00	0.75
2009	26.00	33.60	21.50	26.40	4.75	24.70	2.00	0.75
2010	26.50	34.20	21.80	26.90	4.90	25.10	2.00	0.75
2011	27.00	34.90	22.30	27.40	5.00	25.70	2.00	0.75
2012	27.50	35.50	22.60	27.90	5.05	26.10	2.00	0.75
2013	28.10	36.30	23.20	28.50	5.15	26.70	2.00	0.75
2014	28.70	37.00	23.60	29.10	5.25	27.20	2.00	0.75
2015	29.30	37.80	24.10	29.70	5.40	27.80	2.00	0.75
2016	29.90	38.60	24.60	30.40	5.50	28.50	2.00	0.75
2017	30.50	39.40	25.20	31.00	5.65	29.10	2.00	0.75
2018	31.10	40.10	25.60	31.50	5.75	29.60	2.00	0.75
2019	31.70	40.90	26.10	32.20	5.85	30.10	2.00	0.75
2020	32.30	41.70	26.60	32.80	5.95	30.70	2.00	0.75
2021	32.90	42.50	27.10	33.40	6.05	31.30	2.00	0.75
2022	33.60	43.40	27.70	34.10	6.20	32.00	2.00	0.75
2023	34.30	44.30	28.30	34.80	6.30	32.60	2.00	0.75
Thereafter	34.30	44.30	28.30	34.80	6.30	32.60	0	0.75

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.
(3) 2004 Forecast for 9 months only.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The Operating Subsidiaries carries a relatively minor amount of undeveloped reserves. These reserves are infill wells primarily located in undrilled spacing units at its Hayter and Carlyle property areas. A portion of these infill wells are projected to be upgraded to producing status in 2004 and the remainder in 2005 and 2006.

The Operating Subsidiaries does not see a major uncertainty related to the upgrading of undeveloped reserves. Nevertheless, a catastrophic drop in oil prices might delay infill drilling activity.

Important economic factors that should be taken into consideration that may affect particular components of the reserve data include: oil pricing, power costs and operating expenses.

Significant Factors or Uncertainties

Information in this Annual Information Form contains forward-looking information and estimates with respect to Harvest. This information addresses future events and conditions, and as such involves risks and uncertainties that could cause actual results to differ materially from those contemplated by the information provided. These risks and uncertainties include but are not limited to factors intrinsic in domestic and international politics and economics, general industry conditions including the impact of environmental laws and regulations, imprecision of reserves estimates, fluctuations in commodity prices, interest rates or foreign exchange rates and stock market volatility. The information and opinions concerning the Trust's future outlook are based on information available at December 31, 2003.

Other Oil and Natural Gas Information

Oil and Natural Gas Properties

The Operating Subsidiaries' portfolio of Properties are discussed below. Although the Trust receives income from the NPI from each of the Operating Subsidiaries, all oil and natural gas operations and the management of the Trust are conducted by the Corporation.

In general, the Properties include major oil accumulations which benefit from active pressure support due to an underlying regional aquifer. Generally, the properties have predictable decline rates with costs of production and oil price key to determining the economic limits of production. The Corporation is actively engaged in cost reduction, production and reserve replacement optimization efforts directed at reserve addition through extending the economic life of these producing properties beyond the limits used in the McDaniel Report and developing new proven reserves previously not evaluated by McDaniel. In respect of the Properties, the Corporation has entered into a number of electrical power swaps to manage a portion of the risk associated with electrical power cost volatility, which is a significant portion of the production costs associated with the Properties.

Principal Provost Properties

The following is a description of the Operating Subsidiaries' principal oil and natural gas properties which constitute the Provost Properties as at December 31, 2003. Production stated is gross production to the Operating Subsidiaries, namely the Operating Subsidiaries' interest share before deducting royalties owned by others and without including any royalty interest of the Operating Subsidiaries and, unless otherwise stated, is the exit production for 2003 excluding production from non-operated properties. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2003.

Hayter

The Operating Subsidiaries have an average 93.1% Working Interest in this operated property, which produces approximately 5,000 net BOE/d of 15° API oil from the Dina "B" Pool located in Sections 24, 25, 34 and 35-40-1 W4M. The Hayter pool contains 176 gross (167 net) producing wells. OOIP is estimated at 138 Mmbbls of oil on the Operating Subsidiaries' Working Interest acreage.

The Hayter fluid production is gathered into one of two central batteries located at 8-35-40-1 W4M or 1-34-40-1 W4M in which the Operating Subsidiaries have a 95% Working Interest and is the operator. The batteries have a combined capacity of approximately 200,000 Bbls/d of fluid. Oil from the Hayter area is blended with condensate and shipped from the battery via the Gibson Provost pipeline to the Hardisty terminal. Solution natural gas is conserved and utilized as fuel gas at the batteries, with the remainder processed at the Husky North Hansman Gas Plant located at 8-14-39-03 W4M. Future development of this pool will include additional in-fill drilling on closer spacing, pool extensions through the identification of by-passed reserves and re-completion of existing wells by isolating portions of the horizontal wells that are experiencing higher water production. There is also an opportunity to employ cost reduction practices to improve netbacks and ultimate recovery, employing inclined free-water knockouts and additional disposal. Initial low pressure water disposal results are encouraging for continuing reduction of operating costs and increase in disposal volumes.

Thompson Lake

The Operating Subsidiaries operate the Thompson Lake properties with approximately a 99% Working Interest. Production from the properties is approximately 1,230 BOE/d of 27° API oil, at a 99% water cut, from the Provost Glauconite "A" Pool located in Township 40 and 41 and Range 10 and 11 W4M. The field contains 192 gross producing wells. OOIP is estimated at 50 Mmbbls of oil.

The Thompson Lake fluid production is gathered at a central battery located at 4-2-41-11 W4M in which the Co has a 100% Working Interest. The battery has a capacity of approximately 210,000 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Pipeline to the Hardisty terminal. Solution natural gas is conserved and processed at the Husky Provost Gas Plant at 13-30-40-10 W4M.

A primary operating tactic to enhance the future performance of the Thompson Lake field is to improve overall fluid handling efficiency and by reducing the electrical power requirements associated with water handling. Additional low pressure water disposal capacity will allow production optimization through total fluid increases at the wells that could have a favourable impact on production rates, reserve recoveries and production costs. Additionally, production prioritization is expected to optimize total fluids handling by focusing operational efforts on the most prolific wells.

Killarney

The Operating Subsidiaries own a 93% average Working Interest and the Operating Subsidiaries operate the Killarney field, which was acquired by the Operating Subsidiaries and by the Trust, through the acquisition of certain properties in Killarney directly and through the acquisition of WEI, in the second quarter of 2003. The Killarney field is a Cummings/Dina oil pool within 3.5 miles of Harvest's existing Hayter field. Production is approximately 1,020 BOE/d of 20.4° API oil. The Killarney pool contains 123 gross (114 net) producing oil wells. OOIP is estimated at 51 Mmbbls of oil.

The Killarney fluid production is gathered at two central batteries located at 6-29-41-1 W4M and 10-20-41-1 W4M. The batteries have a total maximum capacity of approximately 175,000 Bbls/d of fluid. Upside may be realized by increasing water disposal capacity for this field.

David North

The Operating Subsidiaries have a 100% Working Interest in this operated property, which produces approximately 700 BOE/d of primarily 23° API oil, at a 98% water cut, from the Lloydminster (which is under waterflood) and Dina sands located in Sections 26 and 27-40-3 W4M. The field contains 54 gross (54 net) producing wells. OOIP is estimated at 18 Mmbbls of oil for the two producing zones.

The fluid production is gathered to the central battery located at 15-26-40-3 W4M in which the Operating Subsidiaries have a 100% Working Interest. The battery has a capacity of approximately 40,000 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Pipeline to the Hardisty terminal. Solution natural gas is conserved and processed at the Husky North Hansman Gas Plant 8-14-39-3 W4M.

Selected well speed-ups and expanded use of inclined free-water knockouts could result in increased efficiency, lower operating costs and increased fluid handling capacity. The Operating Subsidiaries are also considering targeting re-completions for wells that have produced in the Lloydminster and/or Dina zones to be converted to Cummings or Sparky oil producers. Numerous wells have been identified by the Operating Subsidiaries for re-completion.

West Provost

The Operating Subsidiaries hold an average 43.1% Working Interest in this area. Production from the area is approximately 610 BOE/d of primarily 26° API oil, at a 98% water cut, primarily from the Mannville "L" Pool located in Townships 37, 38 and 39-3 W4M. Natural gas production is approximately 200 Mcf/d. The West Provost pool contains 114 gross (43 net) producing oil wells and 15 gross (6 net) producing natural gas wells. OOIP is estimated at 35 Mmbbls of oil.

The majority of the West Provost fluid production in the area is gathered at a central battery located at 3-15-38-03 W4M, in which the Operating Subsidiaries have a 37.5% Working Interest. The battery has a capacity of approximately 115,000 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Provost pipeline to the Hardisty terminal. Solution and non-associated natural gas is conserved and processed at the Husky North, Hansman Lake Gas Plant at 8-14-39-03 W4M. The West Provost area also produces natural gas from 15 gross wells, primarily from the Viking and Colony Formations.

There is an opportunity to employ cost reduction practices to improve netbacks and ultimate recovery employing inclined free-water knockouts and increased water disposal capacity.

Amisk

WEI owns a 75% average Working Interest in the Amisk field and the Operating Subsidiaries operate all production, which was acquired by the Trust through the acquisition of WEI on June 27, 2003. The Amisk field is located on the producing trend, which includes Thompson Lake, Hayter, Killarney and West Provost. Amisk is located 15 miles east of Thompson Lake, produces from the same formation and has similar production characteristics. Production from the field is approximately 690 BOE/d of 22° API oil. The Amisk pool contains 88 gross (66 net) producing oil wells. OOIP is estimated at 62 Mmbbls oil for the entire Amisk pool area.

The Amisk fluid production is gathered at an operated central battery located at 12-15-40-08W4M. The Operating Subsidiaries has identified an opportunity to improve netbacks and ultimate recovery by reducing operating costs, suspending marginal wells and increasing water disposal capacity for the field.

Czar

The Operating Subsidiaries own an average 100% Working Interest in this area (and the Operating Subsidiaries operate all production), which interests acquired by the Trust through the acquisition of WEI on June 27, 2003. The Czar field is located 8 miles due east of Amisk on the same producing trend. Production is approximately 480 BOE/d of 16° API oil. The Czar pool contains 67 gross (67 net) producing oil wells. OOIP is estimated at 34 Mmbbls of oil.

The Czar fluid production is gathered at an operated central battery located at 2-19-40-06W4M. The Operating Subsidiaries have identified an opportunity to improve netbacks and ultimate recovery by reducing operating costs and increasing water disposal capacity for the field.

Bellshill Lake

The Operating Subsidiaries have a 100% Working Interest in 1,120 acres of land in Sections 5 and 6-41-12 W4M which is in proximity to the Bellshill Blairmore Unit. Production from this operated property is approximately 420 BOE/d of primarily 18° API oil, at a 98% water cut, from the Ellerslie "A" Pool and natural gas from the Glauconite "A" Pool. The field contains 20 gross (20 net) producing wells. OOIP is estimated at 27 Mmbbls of oil.

The Bellshill Lake fluid production is gathered at a central battery located at 11-5-41-12 W4M in which the Operating Subsidiaries have a 100% Working Interest. The battery has a capacity of approximately 40,000 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Bellshill Pipeline to the Hardisty terminal. Solution natural gas is conserved and processed at the Husky Hastings Coulee Gas Plant at 1-14-41-15 W4M. Water is re-injected back into the lower Cretaceous aquifer. Development upside includes an additional horizontal drilling location and increases to water injection capacity.

Metiskow

The Operating Subsidiaries have a 100% Working Interest in this operated property, which produces approximately 140 BOE/d of 16° API oil from the Provost Dina "E" Pool located in Sections 22 and 23-39-6 W4M. The field has been developed exclusively with horizontal wells. The pool contains 9 gross (9 net) producing wells. OOIP is estimated at 3.0 Mmbbls of oil.

The Metiskow fluid production is gathered at a central battery located at 5-22-39-6 W4M in which the Operating Subsidiaries have a 100% Working Interest. The battery has a capacity of approximately 13,500 Bbls/d of fluid. Oil is trucked from the battery to the Hardisty terminal. Upside may be realized by increasing water disposal capacity for this field.

Principal Carlyle Properties

The following is a description of the Operating Subsidiaries' principal oil and natural gas properties which constitute the Carlyle Properties (which were acquired by the Operating Subsidiaries in October 2003) as at December 31, 2003. Production stated is gross production to the Operating Subsidiaries, namely the Operating Subsidiaries' interest share before deducting royalties owned by others and without including any royalty interest of the Operating Subsidiaries and, unless otherwise stated, is the exit production for 2003 excluding production from non-operated properties. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2003.

The properties described below constitute the majority of the Carlyle Properties. Additional production of approximately 260 BOE/d is derived from various minor properties. OOIP numbers are published values from the Saskatchewan Government. All oil production is delivered into the Enbridge Saskatchewan pipeline system.

<u>Hazelwood</u>

This area is comprised of nine separate pools producing approximately 1,940 BOE/d of 34° API oil from 142 oil wells in the Tilston formation. As at December 31, 2003, the Operating Subsidiaries held an average 98% Working Interest in 19,107 gross acres including 8,669 net undeveloped acres. The area contains 142 gross (139 net) producing oil wells. OOIP is estimated at 160 Mmbbls of oil for all Hazelwood pools. Operatorship (100% Working Interest in all but one facility) along with extensive proprietary 3D seismic coverage offer control of the opportunity to increase oil production and reserve life through workovers, step-out drilling and horizontal infill drilling. Natural gas volumes at Hazelwood are marketed through an area rural natural gas co-operative.

<u>Moose Valley</u>

This area is comprised of five pools producing approximately 1,070 BOE/d of 28° API oil from 98 oil wells in the Tilston formation. As at December 31, 2003, the Operating Subsidiaries held an average 97% Working Interest in 8,417 gross acres including 3,794 net undeveloped acres. The area contains 98 gross (97 net) producing oil wells. OOIP is estimated at 80 Mmbbls of oil for all Moose Valley pools. Operatorship (100% Working Interest in all but one facility) along with extensive proprietary 3D seismic coverage offer control of the opportunity to increase production and reserve life through workovers, water handling upgrades and water control measures and additional infill and step-out drilling.

<u>Whitebear</u>

This area is comprised of three main pools producing approximately 800 BOE/d of 34° API oil from 67 oil wells in the Tilston formation. As at December 31, 2003, the Operating Subsidiaries held a 100% Working Interest in 11,245 gross acres including 6,204 net undeveloped acres. The area contains 67 gross (58 net) producing oil wells. OOIP is estimated at 120 Mmbbls of oil for all Whitebear pools. A significant portion of the property is located on the Whitebear First Nation Reserve. The Carlyle Properties Vendor holds an option to acquire an additional 23% average Working Interest in 960 gross acres plus royalty interests in 96 acres at Willmar, which is part of the Whitebear area (the "Whitebear Reserve Option Lands"). Operatorship of all facilities along with extensive proprietary 3D seismic coverage offer control of the opportunity to increase oil production and reserve life through workovers, water handling upgrades and water control measures, horizontal infill drilling .

<u>Corning/Flinton</u>

This area is comprised of five pools producing approximately 740 BOE/d of 28.5° API oil from 67 oil wells in the Tilston formation. As at December 31, 2003, the Operating Subsidiaries held an average 100% Working Interest in 13,748 gross acres, including 6,309 net undeveloped acres. The area contains 67 gross (66 net) producing oil wells. OOIP is estimated at 53 Mmbbls of oil for all Corning/Flinton pools. Operatorship (100% WI) in all facilities along with extensive proprietary 3D seismic coverage offer control of the opportunity to increase production and reserve life through workovers and drilling of selected infill and step-out wells.

Parkman East

This area is comprised of the Parkman East pools, producing approximately 280 BOE/d of 33.5° API oil from 37 oil wells in the Tilston formation. As at December 31, 2003, the Operating Subsidiaries held an average 88.1% Working Interest in 6,198 gross acres including 2,506 net undeveloped acres. The area contains 37 gross (26 net) producing oil wells. OOIP is estimated at 230 Mmbbls of oil for all Parkman East pools. Opportunity exists to increase oil production and reserve life through workovers, water handling upgrades and water control measures, and selective infill drilling.

Wauchope/Lightning

This area is comprised of three pools producing approximately 110 BOE/d of 33° API oil from 12 oil wells in the Tilston formation. As at December 31, 2003, the Operating Subsidiaries held an average 93% Working Interest in 4,079 gross acres including 2,514 net undeveloped acres. The area contains 12 gross (11 net) producing oil wells. OOIP is estimated at 26 Mmbbls of oil for all Wauchope/Lightning pools. Operatorship (100% WI) in all facilities along with extensive proprietary 3D seismic coverage offer control of the opportunity to increase production and reserve life through workovers, water handling upgrades and water control measures and additional step-out and new pool drilling.

Incremental Exploitation and Development Potential

Management of the Corporation has identified several opportunities to take advantage of possible development potential in order to increase existing production supplemental to the future development projects included in the determination of the Reserve Values contained in the McDaniel Report. Neither the capital costs nor the potential incremental production associated with these opportunities are reflected in the McDaniel Report. Opportunities being considered include:

- Increasing water handling and water disposal capacity at key fields to add incremental oil volumes. This includes the use of inclined free water knock-outs and additional disposal wells;
- Debottlenecking existing fluid handling facilities and surface infrastructure;
- Infill horizontal drilling and step-out drilling opportunities at Hazelwood beyond those included in the McDaniel Report. Locations are fully defined by 3D seismic;
- Optimizing field oil cut management through the shut-in of select wells and increased total fluid from offset higher oil cut wells. Shut-in wells would be available for restart as oil cuts vary;
- Reperforating existing shut-in wells to access undrained reserves;
- Numerous exploratory opportunities defined by seismic from which value might be extracted by sale or farmout; and
- Selected development drilling opportunities for prolific Alida and Souris Valley subcrop oil accumulations.

Oil And Natural Gas Wells

The following table sets forth the number and status of wells in which the Operating Subsidiaries have a working interest as at December 31, 2003.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	723	598	476	439	21	5	7	3
Saskatchewan	385	369	232	221	-	-	-	-
Total	1,108	967	708	660	21	5	7	3

Properties with no Attributable Reserves

The following table sets out the Operating Subsidiaries' undeveloped land holdings as at January 1, 2004.

	Undeveloped Acres	
	Gross	Net
Alberta	15,549	10,398
Saskatchewan	26,372	25,598
Total	41,921	35,996

The Operating Subsidiaries expect that rights to explore, develop and exploit 5,832 net acres of its undeveloped land holdings will expire by December 31, 2004.

Forward Contracts

For details of material commitments to sell natural gas and crude oil which were outstanding at December 31, 2003 – see note 12 to the Financial Statements contained on pages 50 to 52 in the Trust's annual report, which pages are incorporated herein by reference.

Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment and reclamation costs for surface leases, wells, facilities and pipelines which are expected to be incurred by the Operating Subsidiaries and for the periods indicated:

Period	Abandonment & Reclamation costs net of salvage value (undiscounted and using a 2% inflation rate) ($000)	Abandonment & Reclamation costs net of salvage value (discounted at 10% using a 2% inflation rate) ($000)
Total as at Dec. 31, 2004	29,000	12,200
Anticipated to be paid in 2004	68	65
Anticipated to be paid in 2005	72	61
Anticipated to be paid in 2006	89	71

The number of net wells for which McDaniel estimated that the Operating Subsidiaries would incur abandonment and reclamation costs is 1,969 wells.

Only abandonment costs associated with wells were deducted by McDaniel in estimating future net revenue in the McDaniel Report and all of such costs (without accounting for salvage values) were so deducted.

Capital Expenditures

The following tables summarize capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Operating Subsidiaries' activities for the year ended December 31, 2003 ($000):

Property acquisition costs	
Proved properties	$108,677
Undeveloped properties	-
Exploration costs	-
Development costs	26,623
Total	$135,300

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Operating Subsidiaries participated during the year ended December 31, 2003:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium	-	-	21	18.5
Natural Gas	-	-	-	-
Service	-	-	1	1
Dry	-	-	-	-
Total:	-	-	22	19.5

During 2004, the Operating Subsidiaries plan to drill 32 wells. Fourteen were drilled during the first quarter. The Operating Subsidiaries have commenced a development drilling program in SE Saskatchewan targeting 15 wells drilled for Tilston oil production. As of April 30, 2004 five of these SE Saskatchewan wells have been drilled. The Operating Subsidiaries are continuing development drilling at East Hayter with the addition of up to 12 new wells. Six of these East Hayter wells have been drilled to date. The Operating Subsidiaries are also continuing with a program to add low pressure water disposal to reduce operating costs by reducing consumption of electricity. At Thompson Lake, two new disposal wells were added and an additional three wells are planned in the Provost area.

Production Estimates

The following table sets out the volume of the Operating Subsidiaries' net production estimated 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" and forecast by McDaniel.

	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	(bbls/d)	(bbls/d)	(mcf/d)	(bbls/d)	(BOE/d)
Proved Producing	8,765	4,595	1,115	53	13,599
Proved Developed Non-Producing	-	-	-	-	-
Proved Undeveloped	194	82	12	2	280
Total Proved	8,958	4,677	1,127	55	13,879
Total Probable	294	204	54	-	509
Total Proved Plus Probable	9,241	4,893	1,181	57	14,388

Hayter is the Operating Subsidiaries' largest producing property representing 32% of forecast 2004 production. It is forecast by McDaniel to produce 4,525 Bbls/d of heavy oil.

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:

Average Daily Production Volumes
(before the deduction of royalties)

	2003				
	Q1	Q2	Q3	Q4	Total
Natural Gas(mcfd)	875	1,161	1,453	1,744	1,311
Heavy Oil (bopd)	4,853	5,139	6,010	5,756	5,444
Medium Oil (bopd)	3,181	4,232	5,044	4,662	4,286
Light Oil (bopd)	-	-	-	4,079	1,028
NGL (blpd)	43	67	77	70	64
Total Liquids (blpd)	8,077	9,438	11,131	14,567	10,822
BOE – 6:1					
Total Sales Production:					
Natural Gas (mcf)	78,750	105,651	133,676	160,448	478,515
Heavy Oil (bbls)	436,770	467,649	552,920	529,571	1,987,060
Medium Oil (bbls)	286,290	385,112	464,048	428,912	1,564,390
Light Oil (bbls)	-	-	-	375,310	375,220
NGL (bbls)	3,870	6,097	7,084	6,397	23,360
Total Liquids (bbls)	726,930	858,858	1,024,052	1,340,190	3,950,030
BOE – 6:1	**740,055**	**876,467**	**1,046,331**	**1,366,931**	**4,029,783**

Average Sales Prices Received:	2003				
	Q1	Q2	Q3	Q4	Total
Natural Gas (mcf)	8.85	6.81	6.17	6.01	6.70
Heavy Oil ($/bbl)	33.86	27.16	24.96	24.92	27.34
Medium Oil ($/bbl)	38.96	31.54	31.09	30.13	32.18
Light Oil ($/bbl)	-	-	-	35.56	35.56
Total Oil ($/bbl)	35.88	29.14	27.76	29.59	30.05
NGL ($bbl)	43.28	28.91	23.80	29.18	29.92
Total Oil & Liquids ($/bbl)	35.92	29.14	27.73	29.59	30.05
BOE – 6:1	**35.44**	**28.69**	**27.27**	**29.13**	**29.59**

***Royalties Paid*[(1)]**

	2003 Q1	Q2	Q3	Q4	Total
Heavy Oil ($000)	1,638	1,584	1,665	1,635	6,522
Medium & Light Oil ($000)	1,160	1,576	1,887	4,513	9,135
Natural gas & NGL's ($000)	125	130	281	2220	755
Total Oil ($000)	2,923	3,290	3,832	6,367	6,412
Heavy Oil ($/bbl)	3.75	3.39	3.01	3.09	3.28
Medium & Light Oil ($/bbl)	4.05	4.09	4.07	5.61	4.71
Natural gas & NGL's ($/boe)	7.35	5.50	9.56	6.62	6.36
Total Oil ($/bbl)	3.95	3.96	3.66	4.85	4.18

***Operating Expenses*[(1)]**

	2003 Q1	Q2	Q3	Q4	Total
Heavy Oil ($000)	3,624	3,212	3,838	3,984	14,658
Medium & Light Oil ($000)	3,075	3,256	5,602	734	20,666
Natural gas & NGL's ($000)	106	128	221	265	721
Total Oil ($000)	6,804	6,596	9,661	12,983	36,045
Heavy Oil ($/bbl)	8.30	6.87	6.94	7.52	7.38
Medium & Light Oil ($/bbl)	10.74	8.45	12.07	10.86	10.65
Natural gas & NGL's ($/boe)	6.25	5.42	7.53	7.99	6.99
Total Oil ($/bbl)	9.19	7.53	9.23	9.50	8.94

***Netback Received*[(1)]**

	2003 Q1	Q2	Q3	Q4	Total
Heavy Oil ($/bbl)	21.81	16.90	15.01	14.31	16.68
Medium & Light Oil ($/bbl)	24.17	18.99	14.95	16.19	16.82
Natural gas & NGL's ($/boe)	82.78	58.87	43.75	50.65	56.78
Total Oil ($/bbl)	22.29	17.41	14.38	14.97	16.61

Note:
(1) Information respecting Natural Gas and NGLs has not been reported as production volumes are not material.

DESCRIPTION OF THE TRUST

General

The Trust is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta. The Trust is not managed by a third party manager. Instead, the Trust is managed by the Corporation, its wholly-owned subsidiary, pursuant to the Trust Indenture and the Administration Agreement.

The Trust was established for the purposes of:

(a) acquiring the NPI and similar interests from the Corporation and similar interests and acquiring Direct Royalties;

(b) making payments to the Corporation, to the extent of the Trust's available funds, for 99% of the Corporation's cost of (including any amount borrowed to acquire) any Canadian resource property acquired by the Corporation, and the cost of (including any amount borrowed to fund) certain designated capital expenditures in relation to the Properties;

(c) acquiring or investing in securities of the Corporation and in the securities of any other entity including, without limitation, bodies corporate, partnerships or trusts that are Permitted Investments, and borrowing funds or otherwise obtaining credit for that purpose;

(d) disposing of any part of the Trust Fund, including, without limitation, any securities of the Corporation;

(e) temporarily holding cash and investments for the purposes of paying the expenses and the liabilities of the Trust, making other investments as contemplated by the Trust Indenture, paying amounts payable by the Trust in connection with the redemption of any Trust Units, and making distributions to Unitholders; and

(f) paying costs, fees and expenses associated with the foregoing purposes or incidental thereto.

See "Description of the Trust – Cash Available For Distribution" and "Description of the Trust – Distributable Cash".

The NPI and Direct Royalties

Overview

The NPI consists of the right to receive a monthly payment from the Operating Subsidiaries pursuant to the terms of the NPI Agreements, equal to the amount by which ninety-nine (99%) percent of the gross proceeds from the sale of production attributable to Property Interests for such month (the "NPI Revenues") exceed ninety-nine (99%) percent of certain deductible production costs for such period. The residual 1% share of gross proceeds from the sale of production which does not form part of the NPI is retained by the Operating Subsidiaries, together with any income of the Operating Subsidiaries derived from Properties that are not Working Interests in Canadian resource properties (including the Corporation's 1% share of income from the royalty interests from which the Direct Royalties are derived), is used to defray certain expenses and capital expenditures of the Operating Subsidiaries.

In calculating the NPI, the Operating Subsidiaries deduct various costs and expenses. The Trust also reimburses the Operating Subsidiaries for Crown royalties and other Crown charges payable by the Operating Subsidiaries in respect of production from or ownership of the Corporation's Properties. The Operating Subsidiaries are entitled to set off the right to be so reimbursed against the obligation to pay the NPI.

Pursuant to the NPI Agreements, the Trust must pay to the Operating Subsidiaries the Deferred Purchase Price Obligation. To satisfy the Deferred Purchase Price Obligation, the net proceeds of any issue of the Trust Units or the proceeds from the disposition of the NPI on any Properties are paid to the Corporation. The Trust is not required to pay an amount as a Deferred Purchase Price Obligation except to the extent the Trust has such proceeds available. See "Deferred Purchase Price Obligation" below for a more detailed description of the Deferred Purchase Price Obligation.

Pursuant to the NPI Agreements substantially all of the economic benefit derived from the assets of the Operating Subsidiaries accrues to the benefit of the Trust and ultimately to the Unitholders. The term of each of the NPI Agreements is for so long as there are petroleum and natural gas rights to which the NPI Agreement applies.

In addition to the NPI, the Trust owns a beneficial interest in the Direct Royalties and the Trust may acquire further Direct Royalties. Such Direct Royalties may consist of direct petroleum and natural gas royalty interests and may be acquired from time to time.

Deferred Purchase Price Obligation

Pursuant to the NPI Agreements, the Deferred Purchase Price Obligation consists of an ongoing obligation of the Trust to pay to the Operating Subsidiaries, to the extent of the Trust's available funds, an amount equal to:

(a) the portion of acquisition costs incurred by the Operating Subsidiary from time to time which are attributable to Canadian resource property; plus

(b) certain designated drilling, completion, equipping and other costs, in respect of the Properties; plus

(c) the portion of indebtedness incurred in respect of such acquisition costs and capital expenditures, payable at the time of satisfaction by the Corporation of such indebtedness.

To satisfy the Deferred Purchase Price Obligation, the Trust is required to pay over to the Corporation the net proceeds of any issue of the Trust Units or the proceeds from the disposition of the NPI of any Properties held by the Corporation. The Trust is not obligated to pay an amount as a Deferred Purchase Price Obligation except to the extent the Trust has such proceeds available.

To the extent that the Corporation designates an expenditure as a Deferred Purchase Price Obligation:

(a) if the designated expenditure is funded by issuing additional Trust Units, by the proceeds of dispositions of the Canadian resource property component of Properties, by the disposition of Direct Royalties or by the issuance of debt, it will not be a charge against the income from the NPI, and therefore will not reduce payments of income from the NPI to the Trust or distributions to Unitholders;

(b) the Trust will be obliged to pay to the Corporation 99% of the amount of the designated expenditure to the extent not funded by borrowing by the Corporation;

(c) the cost to the Trust of the designated expenditure will be added to the Canadian oil and natural gas property expenditures account of the Trust, thus creating additional tax deductions (see "Canadian Federal Income Tax Considerations"); and

(d) the additional revenue generated from the Properties acquired by the designated expenditure will be added to the revenues used to calculate income from the NPI, thereby potentially increasing the amount payable to the Trust under the NPI Agreements.

Reserve Fund

Under the NPI Agreements, the Operating Subsidiaries are entitled to pay such amounts of the revenues received from Production and other income received by the Corporation in respect of the Properties into the Reserve Fund if, as and when the Corporation determines, in its reasonable discretion, that it is prudent to do so in accordance with prudent business practices, to provide for payment of production costs which the Corporation estimates will or may become payable in the next six months for which there may not be sufficient revenues to satisfy such costs in a timely manner. Funds retained by the Corporation in the Reserve Fund are required to be used by the Corporation to fund the payment of production costs. To the extent that funds are drawn from the Reserve Fund and used to pay production costs, such amounts will be deducted from the NPI.

Reclamation Fund

Each of the Operating Subsidiaries are liable for their share of ongoing environmental obligations and for the ultimate reclamation of the Properties upon abandonment. Pursuant to the NPI Agreements, the Operating Subsidiaries have established a funding strategy for the purpose of funding currently estimated future environmental and reclamation obligations. To the extent that funds from the reclamation funds are used for site restoration and well and facility abandonment expenditures such amounts are deducted in calculating income from the NPI.

Ongoing environmental obligations are expected to be funded out of debt and cash flow. Those obligations will reduce the amount of income from the NPI payable to the Trust. The Corporation currently estimates that the future environmental and reclamation obligations in respect of the Properties will aggregate approximately $35 million, net of estimated salvage value, over the life of the Properties.

In addition to the identified producing wells and wells capable of production, the Properties include interests in approximately 215 gross (212 net) active injection, disposal or service wells and 294 gross (254 net) suspended or shut-in wells, all of which have been included in the total estimate of the Corporation's future environmental and reclamation obligations.

Cash Available For Distribution

Cash Available For Distribution consists of any amounts received by the Trust pursuant to the NPI and the Direct Royalties, any interest or other income from Permitted Investments, ARTC received by the Trust net of non-deductible Crown royalties that are reimbursed by the Trust to the Operating Subsidiaries, dividends on the shares of the Operating Subsidiaries or any other dividends on securities of the Operating Subsidiaries less all expenses and liabilities of the Trust, including debt service costs, which are due or accrued and which are chargeable to income.

Pursuant to the Trust Indenture and the Administration Agreement, the Corporation calculates income from the NPI for each calendar month and arranges for payment of certain direct expenses of the Trust from the NPI.

The actual amount of Cash Available For Distribution depends on, among other things, the quantity and quality of crude oil, natural gas and natural gas liquids produced, prices received for such production, direct expenses of the Trust, taxes, operating costs, transportation and processing costs, capital expenditures, debt service costs, Crown and other royalties, other Crown charges, net contributions to the reclamation funds, net contributions by the Operating Subsidiaries to the Reserve Fund, and general and administrative costs of the Trust and the Operating Subsidiaries. See "Risk Factors".

The Operating Subsidiaries also have the discretion to incur debt or retain cash in order to modify seasonal and other variations in Cash Available For Distribution. Unitholders may also receive distributions of the net proceeds received from sales of Properties to the extent the Corporation determines not to use those proceeds to acquire additional Properties.

Delay in Cash Available For Distribution

In addition to the usual delays in payment by purchasers of oil and natural gas to the operator of the Properties, and by the operator to the Operating Subsidiaries or the Trust, 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 operator of expenses incurred in the operation of Properties, or the establishment by the operator of reserves for such expenses.

Capital Fund

The Trust retains up to 50% of the Cash Available For Distribution in its Capital Fund to finance future acquisitions and development of Properties with the intent that it will be able to continue to provide or maintain the Cash Available For Distribution over a longer period of time than would otherwise be the case. As at December 31, 2003, the Capital Fund had a deficit of approximately $14.2 million (on March 31, 2004, the Capital Fund has a positive balance of approximately $10.9 million).

Distributable Cash

Distributable Cash consists of the balance of the Cash Available For Distribution after the retention of funds by the Trust for the Capital Fund, which is distributed to Unitholders.

Unitholders of record on a Record Date are entitled to receive monthly cash distributions of the Distributable Cash which will become payable on the 15th day following the Record Date, and if such date of payment is not a Business Day on the next Business Day after the 15th day following the Record Date.

Income Tax Treatment

Any amounts paid by the Trust in respect of acquisition costs and the Deferred Purchase Price Obligation is COGPE of the Trust in the year incurred. The Trust's share of any proceeds of disposition of Canadian resource properties which are receivable as a result of the release of the NPI will reduce the Trust's cumulative COGPE. In determining the portion of Distributable Cash that is taxable to a Unitholder, the Trust is entitled to an annual deduction in respect of its cumulative COGPE account, resource allowance and capitalized issue expenses in accordance with the provisions of the Tax Act. The portion of Distributable Cash to Unitholders that is not taxable in the Trust is treated as a return of capital and reduces the adjusted cost base of Trust Units held as capital property by a Unitholder. In this respect, the taxation of capital distributions is deferred until an actual or deemed disposition of Trust Units occurs or a holder's Trust Units have an adjusted cost base which is less than zero. See "Canadian Federal Income Tax Considerations".

Board of Directors

The Corporation has a board of directors consisting of 5 individuals. Pursuant to the Trust Indenture, Unitholders are entitled to elect the Board of Directors annually. Prior to all annual meetings, the Corporation will deliver an information circular and form of proxy to Unitholders with respect to the election of the directors of the Corporation at any such meeting. See "Information Respecting the Corporation – Directors and Officers of the Corporation".

Delegation of Authority, Administration and Trust Governance

The Corporation (and, accordingly, the Board of Directors of the Corporation) has generally been delegated the significant management decisions of the Trust. In particular, the Trustee has delegated to the Corporation responsibility for any and all matters relating to the following: (i) an offering of securities; (ii) ensuring compliance with all applicable laws, including in relation to an offering; (iii) all matters relating to the content of any offering documents, the accuracy of the disclosure contained therein, and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of the material contracts of the Trust; (v) all matters concerning any underwriting or agency agreement providing for the sale of Trust Units or rights to Trust Units; (vi) all matters relating to the redemption of Trust Units; (vii) all matters relating to the voting rights on any investments in the Trust Fund or any Subsequent Investments; (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

Under the NPI Agreements, the Operating Subsidiaries have the exclusive control and authority over development of, and recovery of petroleum, natural gas and natural gas liquids from, the Properties and lands pooled or unitized therewith, including, without limitation, making all decisions respecting whether, when and how to drill, complete, equip, produce, suspend, abandon and shut-in wells and whether to elect to convert royalties to working interests. The Harvest Board has determined that all significant operational decisions and all decisions relating to: (i) the acquisition and disposition of properties for a purchase price or proceeds in excess of $5 million; (ii) the approval of capital expenditure budgets; (iii) the approval of risk management policies and activities proposed to be undertaken, and (iv) the establishment of credit facilities, shall be made by the Board of Directors.

In exercising its powers and discharging its duties, the Corporation must act honestly and in good faith and exercise the degree of care, diligence and skill that a reasonably prudent oil and natural gas industry advisor and administrator would exercise in comparable circumstances. The Corporation's objective in exercising its powers and discharging its duties is to maximize the income distributable to the Unitholders to the extent consistent with long-term growth in the value of the Trust. In pursuing such an objective, the Corporation employs and will continue to employ prudent oil and natural gas business practices. All of the Corporation's business is and will continue to be conducted in accordance with applicable laws with a view to the best interests of the Unitholders and the Trust.

The Harvest Board reviews on an ongoing basis both the nature and extent of the services required of the Corporation by the Trust and the costs of providing such services.

General and administrative costs are deducted from production revenues in computing income from the NPI to the extent not paid from the residual income of the Corporation or deducted by the Trust in computing Cash Available For Distribution. General and administrative costs are generally charged to the Trust by the Corporation based on direct costs incurred in fulfilling the obligations of the Corporation to the Trust pursuant to the Trust Indenture and the Administration Agreement. The Corporation is entitled to reimbursement for all of its direct and indirect expenses, costs and expenditures in connection with the creation, start-up, set-up and organization of the Trust and the transition from the Provost Properties Vendors and the Carlyle Properties Vendor to the Corporation of ownership, management and operatorship of the Provost Properties and the Carlyle Properties. To the extent that such costs have been incurred to date, they have been paid by the Corporation through drawdowns under a prior credit facility and an interim loan which had been provided to the Trust by Caribou.

Borrowing by the Trust

On July 28, 2003, the Trust entered into the Equity Bridge Notes with the Bridge Lenders which provide for advances of up to $40 million to the Trust to assist with the payment of the Deferred Purchase Price Obligation in connection with the acquisition of the Carlyle Properties. On September 29, 2003, the Equity Bridge Notes were amended to permit advances to be used to pay out the Prior Bank Facility and the Trust entered into the Bridge Notes. The Bridge Notes provide for advances of up to $30 million to the Trust to assist with the payment of the Deferred Purchase Price Obligations as a result of the acquisition of the Carlyle Properties and to pay out the Prior Bank Facility. No commitment or arrangement fee has or will be earned by the Bridge Lenders through the provision of the Bridge Agreements.

The terms of the Bridge Agreements call for quarterly interest payments to be made to the Bridge Lenders in arrears due on the first business day following a calendar quarter. The payments are calculated daily at a fixed rate of 10% per annum using a 365 or 366 (as the case may be) year. Under the Equity Bridge Notes, the Trust has the option to settle the quarterly interest payments with cash or, subject to receipt or applicable regulatory approval, the issue of Trust Units. If the Trust elects to issue Trust Units the Trust is required to give the Bridge Lenders at least 5 business days notice. The number of Trust Units to be issued to the Bridge Lenders to settle a quarterly payment shall be equivalent to the quarterly payment amount divided by 90% of the ten-day weighted average trading price of the Trust Units on TSX over the last 10 trading days of the calendar quarter.

The Trust also has the option to repay the principal amounts outstanding at any time. The Trust is required to give the Bridge Lenders ten business days written notice prior to the Trust's repayment of principal. If the Trust chooses to partially repay the outstanding principal amount, such payment is to be made in cash. Under the Equity Bridge Notes, if the Trust elects to repay the full principal amount plus the accrued quarterly payment at maturity, the Trust then has the option to settle its obligation with cash or, subject to receipt of applicable regulatory approvals, the issue of Trust Units. If the Trust elects to issue Trust Units, the Trust is required to give the Bridge Lenders at least five business days notice. The number of Trust Units to be issued to the Bridge Lenders to settle the principal amount and accrued quarterly payment amount shall be equivalent to the sum of the principal and accrued quarterly payment amounts divided by 90% of the ten-day weighted average trading price of the Trust Units on TSX over the last ten trading days immediately prior to the date that the obligation will be settled. Notwithstanding the above, the outstanding principal portion and all accrued and unpaid interest on the Bridge Agreements is due and payable in full on January 1, 2005. The amount due on January 1, 2005 may be settled by the payment of cash and in the case of the Equity Bridge Notes, subject to receipt of applicable regulatory approvals, the issue of Trust Units, with notice provided and the calculation of the number of Trust Units to be issued as indicated above. Security has been provided to the Bridge Lenders in the form of a fixed and floating debenture on the Trust's NPI. The Bridge Lenders may demand payment of the full amount if specified events of default under the Bridge Agreements occur. The Trust does not have the option to issue Trust Units to satisfy its repayment obligations under such a demand.

Upon completion of the Carlyle Properties Transaction on October 16, 2003, the Corporation repaid $8.5 million of the Equity Bridge Notes (resulting in $25 million being outstanding thereunder) and $25 million of the Bridge Notes resulting in no amount being outstanding thereunder through drawings under the Current Bank Facility.

In 2004, the Trust repaid in full the $25 million outstanding under the Equity Bridge Notes with proceeds from the issuance of the Convertible Debentures.

INFORMATION RESPECTING THE CORPORATION

The Corporation was incorporated under the *Business Corporations Act* (Alberta) on May 14, 2002 as 989131 Alberta Ltd. On May 17, 2002, the Corporation amended its Articles of Incorporation to change its name to Coyote Energy Inc. and on September 17, 2002, the Corporation changed its name to "Harvest Operations Corp.". On January 1, 2004, the Corporation amalgamated with WEI and the amalgamated corporation continued under the name "Harvest Operations Corp.". The head and principal office of the Corporation is located at Suite 1900, 330 - 5th Avenue S.W., Calgary, Alberta, T2P 0L4 and its registered office is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta T2P 3N9. All of the issued and outstanding shares of the Corporation are held in the name of the Trustee for the benefit of, and on behalf of, the Trust.

Business

The Corporation manages and administers the Trust and HST on behalf of the Trust and is responsible for the oil and natural gas technical, investment, engineering, geological, land management, financial and administrative services and commodity marketing services relating to the Properties and the Trust. Each of the directors and senior management of the Corporation have been involved in the oil and natural gas industry for, on average, in excess of 18 years. At April 30, 2004, the Corporation has a staff made up of 48 head office employees and consultants and 62 field employees and consultants/contractors dedicated to the Properties, with key personnel having extensive experience in all technical, operating and financial aspects of the oil and natural gas industry including:

- organizing, operating, managing, developing and optimizing petroleum and natural gas properties;
- evaluating, acquiring and disposing of petroleum and natural gas properties; and
- marketing petroleum, natural gas and natural gas liquids.

Management Policies and Strategies

As a result of management's past experience, the members of the management team have established proven track records in acquiring, developing and operating oil and natural gas reserves. Management of the Corporation believes that the success derived from these experiences can be attributed to several management principles, including:

(a) a focused and rigorous evaluation and acquisition strategy having an objective of acquiring operated oil and natural gas reserves at low costs;

(b) employing operating and management strategies and controls to increase production rates and enhance production netbacks, primarily through production cost reduction;

(c) identifying and exploiting upside opportunities in acquired Properties to increase production and reserve recovery;

(d) acquiring other assets within existing operating areas to achieve operating and development efficiencies; and

(e) managing risk effectively through prudent insurance and commodity hedging programs and hands-on property management.

Activities undertaken by the management of the Corporation on behalf of the Trust are intended to be directed towards:

- optimizing consistent levels of Cash Available For Distribution and ultimately, the Distributable Cash paid to Unitholders;
- capturing the maximum cash flow, production and reserve recovery from the Properties; and
- striving for long-term growth in the value of the Properties and consequently the value of the NPI and the Direct Royalties held by the Trust by improving recovery levels from Provost Properties and acquiring additional Properties.

Borrowing by the Corporation

The Operating Subsidiaries and the Trust are permitted to incur indebtedness to purchase Property Interests, effect capital expenditures or other obligations or expenditures in respect of the Properties or for working capital purposes. Indebtedness of the Operating Subsidiaries to fund the purchase of Canadian resource properties may be repaid with funds received from the Trust pursuant to the Deferred Purchase Price Obligation. The Harvest Board has established the following guidelines with respect to the indebtedness of the Operating Subsidiaries: (i) amounts borrowed to finance the purchase of Properties should not exceed 50% of the Reserve Value of all Properties including those to be acquired at the time of borrowing as shown on the latest available independent engineering report, unless specifically approved by the Board of Directors; and (ii) the estimated annual debt service costs for the 12 months following the borrowing on amounts borrowed to finance capital expenditures or other financial obligations or expenditures required to maintain or improve production from the Properties should not exceed 50% of the estimated income from the NPI and income from Direct Royalties for such 12 month period, unless specifically approved by the Board of Directors. The Operating Subsidiaries are entitled to grant security in priority to the NPI and the Trust is permitted to grant security on the NPI and Direct Royalties to secure the loan of funds directly to the Trust or secure guarantees granted by the Trust of indebtedness of the Operating Subsidiaries. The borrowings of the Trust require approval by the Board of Directors.

Debt service costs of the Operating Subsidiaries are deducted in computing NPI income and debt service costs of the Trust are deducted in computing Cash Available For Distribution. Debt repayment by the Operating Subsidiaries is scheduled to minimize, to the extent possible, any income tax payable by the Operating Subsidiaries.

On October 3, 2003, the Corporation entered into an interim credit facility to provide a $15 million revolving operating demand loan which was used to pay out WEI's credit facility with a Canadian chartered bank and for general working capital purposes. On October 3, 2003, the Corporation paid out $2.9 million in respect of the borrowings and accrued interest on WEI's credit facility. Upon closing of the Carlyle Properties Transaction on October 16, 2003, the interim credit facility was paid out and replaced with the Current Bank Facility described below.

On October 16, 2003, Harvest Operations Corp. entered into the $89 million Current Bank Facility with the Current Lender. The facility bears interest at rates ranging from 0.25% to 1.5% above prime rate, and is dependent upon the Trust's debt to cash flow ratio. The borrowing base is reduced monthly by $4.5 million commencing January 31, 2004. A portion of this facility was used to pay out the $15 million Interim Bank Facility, $31.35 million was used to finance in part the acquisition of the Carlyle Properties, $8.5 million was used to repay a portion of the Equity Bridge Notes and $25 million was used to repay the Bridge Notes.

Borrowing	Base Rate	Debt to Annualized Cash Flow Ratio <1.0x	1.0x – 1.5x	1.5x – 2.0x	2.0x – 3.0x	>3.0x
Canadian $	Cdn. Bank Prime	+0.25%	+0.375%	+0.50%	+0.75%	+1.50%
Banker's Acceptances	Market rates	+1.25%	+1.50%	+1.75%	+2.00%	N/A
U.S. $	U.S. Bank Prime	+0.25%	+0.375%	+0.50%	+0.75%	+1.50%
LIBOR	Market rates	+1.25%	+1.50%	+1.75%	+2.00%	N/A

The Corporation is subject to a standby fee equal to 0.125% per annum on the undrawn amount of the Current Bank Facility.

Security for the Current Bank Facility consists of: a general assignment of book debts; a $150,000,000 debenture with a floating charge over all of the assets of the Corporation; representation as to title of oil and natural gas leases and reserves; subordination agreements on NPI payments, Bridge Agreements payments, and distribution payment restrictions to Unitholders upon demand for repayment or an event of default, or under certain circumstances, upon a borrowing base shortfall or default. Covenants for the Current Bank Facility include: maintenance of a working capital ratio (current assets plus unused portion of the Current Bank Facility divided by current liabilities excluding bank debt) of at least 1:1; maintenance of minimum hedging of 50% and 25% of oil volumes for the first four forward and next four calendar quarters, respectively; and industry standard requirements in respect of reporting, operations, compliance with laws, payment of taxes, environmental, lender access to books and records, maintenance of records, change in control, merger, amalgamation, payment of dividends or distribution of capital, incur additional secured indebtedness or guarantee of obligations of others, dispose of assets with annual proceeds greater than $100,000 and hedge more than 75% of working interest production volumes.

Events of default under the Current Bank Facility include: failure to pay interest or principal when due; failure to meet security or covenants; material misrepresentation; material adverse change in the financial condition of operations of the Corporation; uncontested proceedings initiated to enforce encumbrances on the Corporation's assets that have an aggregate value of $500,000; liquidation, winding-up or dissolution of the Corporation; ceasing to carry on business; and appointment of receiver or trustee appointed by judicial body or pursuant to another agreement.

As of April 30, 2004, approximately $39.7 million is outstanding under the Current Bank Facility.

Commodity Hedging

The following is a summary of the oil sales contracts with price swap or collar features as at December 31, 2003 that have fixed future sales prices:

Commodity collar contracts based on West Texas Intermediate

Daily Quantity	Term	Price per Barrel	Mark to Market Gain (Loss) Cdn $
2,500 Bbls/d	January through December 2004	U.S. $22.00 – 28.10	($2,456,677)
1,000 Bbls/d	January through December 2004	U.S. $23.00 – 27.95 ($18.00)[1]	(1,095,885)
1,000 Bbls/d	January through December 2004	U.S. $25.00 – 28.25 ($18.00)[1]	($954,367)
500 Bbls/d	January through December 2004	U.S. $27.50 – 31.00 ($20.25)[1]	$154,929
500 Bbls/d	January through December 2004	U.S. $27.65 – 33.00 ($21.00)[1]	($47,173)

Commodity swap contracts based on West Texas Intermediate

Daily Quantity	Term	Price per Barrel	Mark to Market Gain (Loss) Cdn $
1,510 Bbls/d	January through March 2004	U.S. $23.23	($1,553,580)
1,300 Bbls/d	January through March 2004	U.S. $24.23	($1,171,187)
500 Bbls/d	January through December 2004	U.S. $24.12 ($15.50)[1]	($1,441,863)
500 Bbls/d	January through December 2004	U.S. $24.25	($1,399,408)
500 Bbls/d	January through December 2004	U.S. $29.32	($203,583)
1,430 Bbls/d	April through June 2004	U.S. $22.93	($1,297,309)
1,200 Bbls/d	April through June 2004	U.S. $25.50	($2,911,765)
1,380 Bbls/d	July through September 2004	U.S. $22.70	($1,098,458)
500 Bbls/d	July through September 2004	U.S. $24.56	($287,414)
1,325 Bbls/d	October through December 2004	U.S. $22.54	($957,680)
500 Bbls/d	October through December 2004	U.S. $24.03	($272,808)
500 Bbls/d	January through December 2004	U.S. $30.50	$74,736
500 Bbls/d	January through December 2005	U.S. $24.00	($811,076)
1,100 Bbls/d	January through March 2005	U.S. $22.38	($714,041)
1,030 Bbls/d	April through June 2005	U.S. $22.18	($652,039)

Commodity swap contracts based on the Lloydminster Blend Crude differential

2,000 Bbls/d	January through December 2004	U.S. ($7.75)[1]	$1,368,005
1,000 Bbls/d	January through December 2004	U.S. ($8.20)[1]	$471,726
500 Bbls/d	January through December 2004	U.S. ($7.90)[1]	$306,622

Note:

(1) The Corporation has sold a put option at the price denoted in parenthesis, for the same volumes as the associated commodity contract. The counterparty may exercise this option if the respective index falls below the specified price on a monthly basis.

The following is a summary of electricity price hedging swap contracts entered into by the Corporation to fix the cost of future electricity usage as at December 31, 2003:

Commodity swap contracts based on electricity prices

Quantity	Term	Price per Megawatt	Mark to Market Gain (Loss)
5MW	January through December 2004	Cdn $46.00	$384,300
5MW	January through December 2004	Cdn $46.00	$384,300
5MW	January through December 2004	Cdn $45.50	$406,260
5MW	January through December 2005	Cdn $43.00	$153,300
9.75MW	January 2004 through March 2006	Cdn $44.50	$1,372,920

Commodity swap based on electricity heat rate

Swaps	Term	Price per Megawatt	Mark to Market Gain (Loss)
5MW	January through December 2005	8.40 GJ/MWh	$46,253

Foreign Currency Contracts

Monthly Contract Amount	Term	Contract Rate	Mark to Market Gain (Loss) Cdn $
U.S. $3 million	January through December 2004	1.3333 Cdn / U.S.	$1,735,435

At December 31, 2003, the net mark-to-market unrealized loss for all the financial derivative contracts entered into by the Corporation was approximately $12,467,527. The Corporation has provided a deposit to the counterparties with some of its financial derivative contracts, based on the mark-to-market value of those contracts at the end of the trading day. As at December 31, 2003, this amount totalled $11,899,127 and is recorded in the prepaid expense and deposits balance.

Directors and Officers of the Corporation

The names, municipalities of residence, present positions with the Corporation and principal occupations during the past five years of the directors and officers of the Corporation are set out in the table below and in the text which follows thereafter.

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held (1)	Principal Occupation
John A. Brussa (2)(4) Calgary, Alberta	Director	241,600	Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP (a law firm).
M. Bruce Chernoff (3)(4) Calgary, Alberta	Director, Chairman	5,222,723 (7)	Professional Engineer; Chairman of the Corporation; President and Director of Caribou (a private investment management company) since June 1999; from April 2000 to October 2001, Executive Vice President and Chief Financial Officer of Petrobank Energy and Resources Ltd. ("Petrobank") (a public oil and natural gas company); from February to June 1999, Executive Vice President and Chief Financial Officer of Pacalta Resources Ltd. ("Pacalta") (a public oil and natural gas company); prior thereto, Executive Vice President of Pacalta.
Hank B. Swartout (3) Calgary, Alberta	Director	628,774	Chairman, President and Chief Executive Officer of Precision Drilling Corporation since July, 1987.

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held (1)	Principal Occupation
Verne G. Johnson (2)(3) Calgary, Alberta	Director	20,000	President of KristErin Resources Inc., a private family company since January 2000; Senior Vice President, Funds Management of Enerplus Resources Group from 2000 to 2002; prior thereto, President and Chief Executive Officer of AltaQuest Energy Corporation from 1999 to 2000; prior thereto, President of Ziff Energy Group (an energy consulting company) from 1997 to 1999; prior thereto, President and Chief Executive Officer of ELAN Energy Inc. (a public oil and natural gas company) from 1989 to 1997.
Hector J. McFadyen (2)(4) Calgary, Alberta	Director	20,000	Independent businessman and Director of Hunting PLC (a UK based public international oil services company); director of Computershare Trust Company of Canada (a private Canadian company that manages various trust related activities for public and private companies throughout North America); director of Aluma Systems (a private Canadian company providing industrial and concrete construction services); formerly, President, Midstream Division, Alberta Energy Company Ltd. (a public oil and natural gas company).
Jacob Roorda Calgary, Alberta	President	158,348 (8)	Professional Engineer, President of the Corporation; from June 1999 to July 2002, Managing Director, Research Capital (a mid-sized investment banking dealer); from January 1996 to March 1999, Vice President, Corporate, Director and co-founder of PrimeWest Energy Trust ("PrimeWest") (a public energy trust); from May 1991 to January 1996, Manager, Business Development, Fletcher Challenge (a private oil and natural gas company).
J.A. Ralston Calgary, Alberta	Vice President, Operations	107,262	Vice President, Operations of the Corporation; from 1996 to 2002, Manager, Production of Penn West Petroleum ("PennWest") (a public oil and natural gas company).
David M. Fisher Calgary, Alberta	Vice President, Finance	76,424 (9)	Vice President, Finance of the Corporation since October 2002; from September 1998 to October 2002, Director, Vice President, Finance and Chief Financial Officer of Integra Resources Ltd. ("Integra") (a private oil and natural gas corporation); from April 1995 to July 1998, Vice President, Finance and Chief Financial Officer of Canrise Resources Ltd. (a public oil and natural gas corporation); from June 1994 to April 1995 independent consultant; from April 1985 to May 1994, Manager, Corporate Reporting of Canadian Hunter Exploration Ltd.
David J. Rain Calgary, Alberta	Corporate Secretary	80,700 (10)	Chartered Accountant; Corporate Secretary of the Corporation; Vice President, Finance and Chief Financial Officer of Petrobank since October 2001; Vice President and Director of Caribou since April 2001; from April 2000 to September 2001, Director, Corporate Finance of Petrobank; from May 1997 to June 1999, Corporate Controller and Treasurer of Pacalta.

Notes:

(1) Represents all Trust Units held directly or indirectly or over which such person exercises control or direction as at September 30, 2003. Based upon information provided by the director or officer to the Trust.

(2) Member of the Audit and Corporate Governance Committee.
(3) Member of the Reserves, Safety and Environment Committee.
(4) Member of the Compensation Committee.
(5) The Corporation does not have an executive committee.
(6) The terms of office of all of the directors will expire at the next annual shareholders' meeting of the Corporation.
(7) Includes Trust Units held by Caribou, a company controlled by Mr. Chernoff, and Trust Units held in RESP accounts for the benefit of Mr. Chernoff's children.
(8) Includes 43,919 Trust Units held in Mr. Roorda's spouse's account which is controlled by Mr. Roorda.
(9) Excludes 7,250 Trust Units held in the name of Mr. Fisher's children but otherwise controlled by Mr. Fisher.
(10) Includes 30,700 Trust Units held by Mr. Rain's spouse.

As at April 30, 2004, the directors and officers of the Corporation and their associates and affiliates, as a group, hold, directly or indirectly, or exercise control or direction over, approximately 6,555,831 Trust Units or 37.9% of the outstanding Trust Units.

The following is a brief description of the background of each of the senior officers and directors of the Corporation. The past performance of each of the individuals indicated below is not necessarily indicative of future performance.

Jacob Roorda, President

Mr. Roorda is a Professional Engineer and holds a Bachelor of Applied Science (Eng.) degree from Queen's University and an MBA from the University of Calgary.

Following university, Mr. Roorda held a number of senior engineering positions with Dome Petroleum Ltd. From 1987 to 1991, Mr. Roorda was a Vice President in the equity research group and was a ranked oil and natural gas analyst at BZW Canada Ltd., in Toronto.

From 1991 to 1996, Mr. Roorda was Manager, Business Development at Fletcher Challenge. In January 1996, Mr. Roorda co-founded PrimeWest (a public energy trust) and served as Vice President, Corporate and Director of PrimeWest. Mr. Roorda was responsible for overseeing the acquisition strategies of PrimeWest. While at Fletcher and PrimeWest, Mr. Roorda was responsible for closing in excess of $650 million of oil and natural gas property acquisitions.

From June 1999 to July 2002, Mr. Roorda was a Managing Director of Research Capital, an investment-banking firm. At Research Capital, Mr. Roorda was responsible for the overall direction and operations of the Calgary investment banking office of the firm.

J.A. Ralston, Vice President, Operations

Mr. Ralston completed the Management Development Program at the University of Calgary in 1994.

Mr. Ralston was employed with Petro-Canada from 1980 through June 1994 in a broad range of field operating positions of increasing responsibility. During his tenure at Petro-Canada, Mr. Ralston was responsible for construction of field facilities and pipelines, natural gas plant and field operations, procurement, reservoir management, drilling and workovers.

Mr. Ralston commenced employment with Penn West in July 1994 where he worked until June 2002. Since 1997, Mr. Ralston served as Production Manager, responsible for overseeing all of Penn West's 100,000 BOE/d production operations, 270 field staff and an annual budget of $200 million. Mr. Ralston was responsible for all areas of operations including engineering, exploitation, production optimization, capital management, planning, construction and budgeting.

David M. Fisher, Vice President, Finance

Mr. Fisher is a Chartered Accountant and graduated in 1980 with a Bachelor of Commerce degree from the University of Alberta. Mr. Fisher has in excess of 20 years experience in financial reporting, management and administration of entities active in the oil and natural gas industry.

From September 1998 to October 2002, Mr. Fisher was a founder, Director and Vice President, Finance and Chief Financial Officer of Integra, a private upstream oil and natural gas corporation with assets located in the province of Alberta. Mr. Fisher was responsible for all financial aspects of Integra including reporting systems, financial reporting, securing equity and bank financing, managing financial assets, taxation, and working with legal counsel and transfer agents in the management of shareholder and regulatory items.

From April 1995 to July 1998, Mr. Fisher was the Vice President, Finance and Chief Financial Officer of Canrise. Canrise was a public upstream oil and natural gas corporation with assets located in west-central Alberta.

During the period June 1980 to April 1995 Mr. Fisher's was an external auditor for KPMG Chartered Accountants (formerly Peat Marwick Mitchell & Co.), incentives auditor for Energy Mines and Resources Canada, Manager of Corporate Reporting for Canadian Hunter Exploration Ltd. and an independent consultant providing financial administration for domestic and international entities.

John A. Brussa, Director

Mr. Brussa is a barrister and solicitor and has been a partner at Burnet, Duckworth & Palmer LLP in Calgary since 1987. Mr. Brussa is recognized as a leading tax practitioner in Canada and sits on the board of directors of several Canadian public companies.

M. Bruce Chernoff, Director and Chairman

Mr. Chernoff is a Professional Engineer with a Bachelor of Applied Science degree in Chemical Engineering from Queen's University. Mr. Chernoff commenced employment with Pacalta in 1988. Pacalta was a public junior oil and natural gas company with operations in Canada. Mr. Chernoff held various senior positions with Pacalta including Executive Vice-President and Chief Financial Officer. Mr. Chernoff was a director of Pacalta from 1992 until Pacalta was purchased by Alberta Energy Company in May 1999 for $1 billion.

Mr. Chernoff initiated the formation of Caribou, of which he is the President and a Director, in June 1999, to make various investments. Mr. Chernoff became a Director, and the Executive Vice President and Chief Financial Officer of Petrobank in March 2000. Mr. Chernoff resigned as Chief Financial Officer of Petrobank in October 2001 to focus on his other business interests, but remains a director of the company. Mr. Chernoff initiated the formation of the Corporation in June 2002 to pursue oil and natural gas development and acquisition opportunities.

Hank B. Swartout, Director

Mr. Swartout is the Chairman of the Board, President and Chief Executive Officer of Precision Drilling Corporation, the largest Canadian integrated oilfield and industrial services contractor and a global provider of products and services to the energy industry.

Verne G. Johnson, Director

Mr. Johnson received a Bachelor of Science degree in Mechanical Engineering from the University of Manitoba in 1966. He immediately commenced employment with Imperial Oil Limited, which continued until 1981 (including two years with Exxon Corporation in New York from 1977 to 1979). In 1981, Mr. Johnson joined Liberty Petroleum Ltd. as President and Chief Executive Officer. In 1982, he joined Roxy Petroleum Ltd. as Vice President, Production, remaining until 1987 when he joined Paragon Petroleum Ltd. as President. In 1989, Mr. Johnson joined ELAN Energy Inc. (then Lasmo Canada Inc.) as President and a Director. Following the sale of ELAN in 1997, he became President of Ziff Energy Group until 1999, then President of AltaQuest Energy Corporation and he then joined the Enerplus Resources Group in 2000, becoming Senior Vice President of Funds Management. In February 2002, he departed from the Enerplus Resources Group and remains as President of his private family company, KristErin Resources Inc.

Hector J. McFadyen, Director

Mr. McFadyen holds a Master of Arts (Econ.) degree from the University of Calgary and a Bachelor of Arts (Econ.) degree from Sir George Williams University.

Mr. McFadyen was employed at the Alberta Energy and Utilities Board (formerly the Oil and natural gas Conservation Board) between 1969 and 1976, primarily within its Economics Department.

Mr. McFadyen began work for Alberta Energy Company Ltd. ("AEC"), now EnCana Corporation ("EnCana"), in 1976. EnCana is one of the largest independent oil and natural gas producers in North America. Mr. McFadyen developed a number of significant business units within AEC, developing experience in a broad range of businesses and disciplines. Such experience included project development and investments across North America, Latin America, Asia and Europe. At AEC, Mr. McFadyen served as a member of the senior executive team involved in recommending and implementing the strategic plan for the company. As President of the Forest Products Division, he assumed responsibility for development and implementation of the business strategy for an Alberta based forest products business. Mr. McFadyen also served as the President of the Midstream Division of AEC since 1995, having responsibility for the company's pipelines and natural gas storage businesses. Mr. McFadyen retired from EnCana in 2002.

Mr. McFadyen is a member of the board of directors of Hunting PLC ("Hunting"), a UK-based public corporation engaged in oil services, and oil and natural gas marketing and distribution activities internationally. Hunting carries on its oil and natural gas marketing and distribution activities in North America through its wholly-owned subsidiary, Gibson Energy Ltd. Mr. McFadyen is also a member of the Board of Directors of Computershare Trust Company of Canada, a private Canadian company that manages various trust related activities for public and private companies throughout North America. Mr. McFadyen is also a director of Aluma Systems, a private Canadian company providing industrial and concrete construction services.

David J. Rain, Corporate Secretary

Mr. Rain is a Chartered Accountant and holds a Bachelor of Commerce degree from the University of Saskatchewan (1986).

Mr. Rain articled at KPMG LLP Chartered Accountants and was a Manager in their audit group until he departed in 1992. Mr. Rain served in senior financial positions at Nowsco Well Service Ltd., an oilfield service company with worldwide operations, from 1992 through August 1996. Mr. Rain was the Chief Financial Officer of Trican Well Service Ltd, an oilfield service company with operations in Alberta and Saskatchewan, from October 1996 through April 1997. Mr. Rain joined Pacalta in May 1997 as Corporate Controller. Pacalta was an oil and natural gas exploration and production company with operations primarily in Ecuador. When AEC acquired Pacalta in 1999, Mr. Rain joined Mr. Chernoff at Caribou, and became Director, Corporate Finance at Petrobank in March 2000. Mr. Rain assumed the position of Vice President, Finance and Chief Financial Officer of Petrobank in October 2001 and resigned in March 2004. Currently, Mr. Rain is the Chief Financial Officer of Caribou.

Corporate Cease Trade Orders or Bankruptcies

No director, officer or promoter of the Corporation or shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation has, within the last 10 years, been a director, officer or promoter of any reporting issuer that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the reporting issuer access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver-manager or trustee appointed to hold the assets of that person.

Penalties or Sanctions

No director, officer or promoter of the Corporation or shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Personal Bankruptcies

No director, officer or promoter of the Corporation, or a shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such persons, has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or been subject to or instituted any proceeding, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the individual.

SHARE CAPITAL OF THE CORPORATION

The share capital of the Corporation currently consists of an unlimited number of common shares and an unlimited number of first preferred shares. As at the date hereof, one hundred common shares of the Corporation are outstanding. Such shares are held by the Trustee for and on behalf of the Trust. The voting of such shares is governed by the provisions of the Trust Indenture and the Trust is not entitled, without the direction of Unitholders, to exercise its rights as a shareholder of the Corporation except as permitted by the Trust Indenture. See "Trust Indenture – Exercise of Voting Rights Attached to Shares of the Corporation".

TRUST INDENTURE

The following is a summary of the Trust Indenture and other matters regarding the structure and operations of the Trust.

Trust Units

An unlimited number of Trust Units may be created and issued pursuant to the Trust Indenture. As of April 30, 2004, there were 17,303,353 Trust Units issued and outstanding. Each Trust Unit entitles the holder thereof to one vote at any meeting of the holders of Trust Units and represents an equal undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding-up of the Trust. All Trust Units outstanding from time to time shall be entitled to equal shares of any distributions by the Trust, and in the event of termination or winding-up of the Trust, in any net assets of the Trust. All Trust Units shall rank among themselves equally and rateably without discrimination, preference or priority. Each Trust Unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the Trust Units held by such holder (see "Redemption Right" below) and to one vote at all meetings of Unitholders for each Trust Unit held. See "Risk Factors – Nature of Trust Units".

Special Voting Units

At the 2003 Unitholders' Meeting, the Unitholders approved an amendment to the Trust Indenture to provides for the issuance of an unlimited number of special voting units. Each special voting unit will entitle the holder thereof to such number of votes at meetings of Unitholders as may be prescribed by the Board of Directors of the Corporation in the resolution authorizing the issuance of any such special voting units.

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust Fund or the obligations or affairs of the Trust or with respect to any act or omission of the Trustee or any other person in the performance or exercise, or purported performance or exercise, of any obligation, power, discretion or authority conferred upon the Trustee or such other person hereunder or with respect to any transaction entered into by the Trustee or by any other person pursuant to the Trust Indenture. No Unitholder shall be liable to indemnify the Trustee or any such other person with respect to any such liability or liabilities incurred by the Trustee or by any such other person or persons or with respect to any taxes payable by the Trust or by the Trustee or by any other person on behalf of or in connection with the Trust. Notwithstanding the foregoing, to the extent that any Unitholders are found by a court of competent jurisdiction to be subject to any such liability, such liability shall be enforceable only against, and shall be satisfied only out of, the Trust Fund and the Trust (to the extent of the Trust Fund) is liable to, and shall indemnify and save harmless any Unitholder against any costs, damages, liabilities, expenses, charges or losses suffered by any Unitholder from or arising as a result of such Unitholder not having any such limited liability. See "Risk Factors – Unitholder Limited Liability".

Issuance Of Trust Units

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Harvest Board may determine. The Trust Indenture also provides that the Corporation may authorize the creation and issuance of debentures, notes and other evidences of indebtedness of the Trust from time to time on such terms and conditions to such persons and for such consideration as the Corporation may determine.

Borrowing By the Trust

Pursuant to the Trust Indenture, the Trustee is permitted to, directly or indirectly, borrow money from or incur indebtedness to any person and in connection therewith, to guarantee, indemnify or act as a surety with respect to payment or performance of any indebtedness, liabilities or obligation of any kind of any person, including, without limitation, the Corporation and any subsidiary of the Trust; to enter into any other obligations on behalf of the Trust; or enter into any subordination agreement on behalf of the Trust or any other person, and to assign, charge, pledge, hypothecate, convey, transfer, mortgage, subordinate, and grant any security interest, mortgage or encumbrance over or with respect to all or any of the Trust Fund or to subordinate the interests of the Trust in the Trust Fund to any other person.

Debt service costs incurred by the Trust are deducted in computing the Cash Available For Distribution.

Redemption Right

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 requiring redemption. Upon receipt of the notice to redeem Trust Units by the Trust, the holder thereof shall only be entitled to receive a price per Trust Unit (the "Market Redemption Price") equal to the lesser of: (i) 90% of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to the Trust for redemption; and (ii) 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 so tendered for redemption.

For the purposes of this calculation, "market price" will be an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that, if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than 5 of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day.

The "closing market price" shall be: an amount equal to the closing price of the Trust Units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of the Trust Units if there was trading and the exchange or other market provides only the highest and lowest prices of Trust Units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date.

The aggregate 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 cheque drawn on a Canadian chartered bank or trust company in Canadian money payable on the last day of the following month. The entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitation that the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month and in any preceding calendar month during the same year shall not exceed $100,000; provided that, the Corporation may, in its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in such calendar month shall be paid on the last day of the following month as follows: (i) firstly, by the Trust distributing Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust Units tendered for redemption, and (ii) secondly, to the extent that the Trust does not hold Notes having a sufficient principal amount outstanding to effect such payment, by the Trust issuing its own promissory notes (herein referred to as "Redemption Notes") to the Unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall.

If, at the time Trust Units are tendered for redemption by a Unitholder, the outstanding Trust Units are not listed for trading on the TSX and are not traded or quoted on any other stock exchange or market which the Corporation considers, in its sole discretion, to represent fair market value for the Trust Units or the normal trading of the outstanding Trust Units is suspended or halted on any stock exchange on which the Trust Units are listed for trading or, if not so listed, on any market on which the Trust Units are quoted for trading, on the date such Trust Units are tendered for redemption or for more than five trading days during the 10 trading day period, 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 the Corporation as at the date on 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 the Trust: (i) a cash payment; or (ii) a distribution of Notes and/or Redemption Notes as described above.

It is anticipated that this Redemption Right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Redemption 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 such Redemption Notes. Redemption Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Non-Resident Unitholders

It is in the best interests of Unitholders that the Trust qualify as a "unit trust" and a "mutual fund trust" under the Tax Act. Certain provisions of the Tax Act require that the Trust not be established nor maintained primarily for the benefit of Non-Residents. Accordingly, in order to comply with such provisions, the Trust Indenture contains restrictions on the ownership of Trust Units by Unitholders who are Non-Residents. In this regard, the Trust shall, among other things, take all necessary steps to monitor the ownership of the Trust Units. If at any time the Trust becomes aware that the beneficial owners of 49% or more of the outstanding Trust Units are or may be Non-Residents or that such a situation is imminent, the Trust, by or through the Corporation on the Trust's behalf, shall take such action as may be necessary to carry out the intentions evidenced herein. For the purposes of this Section, "Non-Residents" means non-residents of Canada within the meaning of the Tax Act.

Meetings of Unitholders

The Trust Indenture provides that meetings of Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors of the Trust, the approval of amendments to the Trust Indenture (except as described under "– Amendments to the Trust Indenture"), the sale of the property of the Trust as an entirety or substantially as an entirety, and the commencement of winding-up the affairs of the Trust. Meetings of Unitholders will be called and held annually for, among other things, the election of the directors of the Corporation and the appointment of the auditors of the Trust.

A meeting of Unitholders may be convened at any time and for any purpose by the Corporation and must be convened, except in certain circumstances, if requisitioned by the holders of not less than 20% of the Trust Units then outstanding by a written requisition. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

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

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Unitholders in accordance with the requirements of applicable laws.

Exercise of Voting Rights Attached to Shares of the Corporation

The Trust Indenture prohibits the Trustee from voting the shares of the Corporation with respect to (i) the election of directors of the Corporation, (ii) the appointment of auditors of the Corporation or (iii) the approval of the Corporation's financial statements, except in accordance with an Ordinary Resolution adopted at an annual meeting of Unitholders. The Trust Indenture also provides that the Trustee shall not, after the Closing, vote the shares to authorize:

(a) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets of the Corporation, except in conjunction with an internal reorganization of the direct or indirect assets of the Corporation as a result of which either the Corporation or the Trust has the same, or substantially similar, interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization;

(b) any statutory amalgamation of the Corporation with any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(c) any statutory arrangement involving the Corporation except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(d) any amendment to the articles of the Corporation to increase or decrease the minimum or maximum number of directors; or

(e) any material amendment to the articles of the Corporation to change the authorized share capital or amend the rights, privileges, restrictions and conditions attaching to any class of the Corporation's shares in a manner which may be prejudicial to the Trust;

without the approval of the Unitholders by Special Resolution at a meeting of Unitholders called for that purpose.

Trustee

Valiant Trust Company is the trustee of the Trust. All of the administrative and management powers of the Trustee relating to the Trust and the operations of the Trust have been delegated to the Corporation pursuant to the Trust Indenture and the Administration Agreement. See "Description of the Trust – Delegation of Authority, Administration and Trust Governance". Notwithstanding this general delegation, pursuant to the Administration Agreement, the Trustee has agreed not to delegate any authority to manage the following affairs of the Trust:

(a) the issue, certification, countersigning, transfer, exchange and cancellation of certificates representing Trust Units;

(b) the maintenance of a register of Unitholders;

(c) the distribution of Distributable Cash to Unitholders, although the calculation of the amount of the distribution shall be made by the Corporation and approved by the Harvest Board and submitted by the Corporation to the Trustee for distribution to the Unitholders;

(d) the mailing of notices, financial statements and reports to Unitholders pursuant to the Trust Indenture, although the Corporation shall be responsible for the preparation or causing the preparation of such notices, financial statements and reports;

(e) the provision of a basic list of registered Unitholders to Unitholders in accordance with the procedures outlined in the Trust Indenture;

(f) the amendment or waiver of the performance or breach of any term or provision of the Trust Indenture on behalf of the Trust;

(g) the renewal or termination of the Administration Agreement on behalf of the Trust; and

(h) any matter which requires the approval of the Unitholders under the terms of the Trust Indenture.

The Trustee is required under the Trust Indenture to 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 initial term of the Trustee's appointment is until the first annual meeting of Unitholders. The Unitholders shall, at the first annual meeting of the Unitholders, re-appoint, or appoint a successor to the Trustee for an additional one year term, and thereafter, the Unitholders shall reappoint or appoint a successor to the Trustee at the annual meeting of Unitholders following the reappointment or appointment of the successor to the Trust. The Trustee may also be removed by the Corporation upon delivery of a notice in writing by the Corporation to the Trustee in limited circumstances. Such resignation or removal becomes effective only upon the approval of the Unitholders by Special Resolution, the acceptance or appointment of a successor trustee and the assumption by the successor trustee of all obligations of the Trustee and in the same capacity.

Liability of the Trustee

The Trustee, its directors, officers, employees, shareholders and agents shall not be liable to any Unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to the Trust or the Trust Fund, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under the Trust Indenture, including, without limitation, any action taken or not taken in good faith in reliance on any documents that are, *prima facie*, properly executed, any depreciation of, or loss to, the Trust Fund incurred by reason of the sale of any asset, any inaccuracy in any valuation provided by any other appropriately qualified person, any reliance on any such evaluation, any action or failure to act of the Corporation, or any other person to whom the Trustee has, with the consent of the Corporation, delegated any of its duties under the Trust Indenture, or any other action or failure to act (including failure to compel in any way any former trustee to redress any breach of trust or any failure by the Corporation to perform its duties under or delegated to it under the Trust Indenture or any other contract), unless such liabilities arise out of the gross negligence, wilful default or fraud of the Trustee or any of its directors, officers, employees or shareholders. If the Trustee has retained an appropriate expert, adviser or legal counsel with respect to any matter connected with its duties under the Trust Indenture or any other contract, the Trustee may act or refuse to act based on the advice of such expert, adviser or legal counsel, and the Trustee shall not be liable for and shall be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, adviser or legal counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under the Trust Indenture, the Trustee is and shall be conclusively deemed to be acting as Trustee of the assets of the Trust and shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust or the Trust Fund. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Amendments to the Trust Indenture

The Trust Indenture may be amended or altered from time to time by Special Resolution. The Trustee may, without the consent, approval or ratification of any of the Unitholders, amend the Trust Indenture for the purpose of:

- ensuring the Trust's continuing compliance with applicable laws or requirements of any governmental agency or authority of Canada or of any province;

- ensuring that the Trust will satisfy the provisions of each of subsections 108(2) and 132(6) of the Tax Act as from time to time amended or replaced;

- ensuring that such additional protection is provided for the interests of Unitholders as the Trustee may consider expedient;

- removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or any supplemental indenture, any Direct Royalties Sale Agreement, and any other agreement of the Trust or any Offering Document pursuant to which securities of the Trust are issued with respect to the Trust, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee and of the Trust Unitholders are not prejudiced thereby;

- providing for the electronic delivery by the Trust to Unitholders of documents relating to the Trust (including annual and quarterly reports, including financial statements, notices of Unitholder meetings and information circulars and proxy related materials) once applicable securities laws have been amended to permit such electronic delivery in place of normal delivery procedures, provided that such amendments to the Trust Indenture are not contrary to or do not conflict with such laws;

- curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that in the opinion of the Trustee the rights of the Trustee and of the Unitholders are not prejudiced thereby; and

- making any modification in the form of the Trust Unit certificates to conform with the provisions of the Trust Indenture, or any other modifications provided the rights of the Trustee and the Unitholder are not prejudiced thereby.

Take-Over Bid

The Trust Indenture contains provisions to the effect that if a take-over bid is made for the Trust Units and not less than 90% of the Trust Units (other than Trust Units held at the date of the takeover bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Trust Units held by Unitholders who did not accept the takeover bid on the terms offered.

Termination of the Trust

Unitholders may vote to terminate the Trust at any meeting of the Unitholders duly called for that purpose, 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 outstanding Trust Units; (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 Unitholders.

Unless the Trust is earlier terminated or extended by vote of the Unitholders, the Trustee shall commence to wind-up the affairs of the Trust on December 31, 2099. In the event that the Trust is wound-up, the Trustee will sell and convert into cash the Direct Royalties and other assets comprising the Trust Fund in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate the Trust Fund, and shall in all respects act in accordance with the directions, if any, of the Unitholders in respect of termination authorized pursuant to the Special Resolution authorizing the termination of the Trust. However, in no event shall the Trust be wound-up until the Direct Royalties have been disposed of. After paying, retiring or discharging, or making provision for the payment, retirement, or discharge of all known liabilities and obligations of the Trust and after providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of the property of the Trust among the Unitholders in accordance with their Pro Rata Share.

Reporting to Unitholders

The consolidated financial statements of the Trust will be audited annually by an independent recognized firm of chartered accountants. The audited consolidated financial statements of the Trust, together with the report of such chartered accountants, will be mailed by the Corporation to Unitholders and the unaudited interim consolidated financial statements of the Trust will be 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.

DEBENTURES

As at April 30, 2004, $59,000,000 principal amount of Debentures of the Trust were outstanding.

The following is a summary of the material attributes and characteristics of the Debentures. This summary does not purport to be complete and is subject to, and qualified by, reference to the terms of the Debenture Indenture with respect to the Debentures.

General

The Debentures were issued under the Debenture Indenture. The Debentures authorized for issue are limited in aggregate principal amount to $60,000,000. The Trust may, however, from time to time, without the consent of the holders of the Debentures but subject to the limitations described herein, issue additional debentures of the same series or of a different series under the Debenture Indenture, in addition to the Debentures offered hereby.

The Debentures are dated January 29, 2004 and mature on May 31, 2009. The Debentures are issuable only in denominations of $1,000 and integral multiples thereof.

The Debentures bear interest from the date of issue at 9% per annum, which is payable semi-annually in arrears in equal instalments (other than in respect of the period from January 29, 2004 to, but excluding, May 31, 2004) on May 31 and November 30 in each year, commencing on May 31, 2004. The first interest payment will include interest accrued from January 29, 2004 to, but excluding, May 31, 2004.

The principal amount of the Debentures is payable in lawful money of Canada or, at the option of the Trust and subject to applicable regulatory approval, by payment of Trust Units as further described under "Payment upon Redemption or Maturity" and "Redemption and Purchase". The interest on the Debentures will be payable in lawful money of Canada including, at the option of the Trust and subject to applicable regulatory approval, in accordance with the Unit Interest Payment Election as described under "Interest Payment Option".

The Debentures are direct obligations of the Trust and will not be secured by any mortgage, pledge, hypothec or other charge and will be subordinated to other liabilities of the Trust as described under "- Subordination". The Debenture Indenture does not restrict the Trust from incurring additional indebtedness or from mortgaging, pledging or charging its properties to secure any indebtedness.

Conversion Privilege

The Debentures are convertible at the holder's option into fully paid and non-assessable Trust Units at any time prior to the close of business on the earlier of May 31, 2009 and the business day immediately preceding the date specified by the Trust for redemption of the Debentures, at a conversion price of $14.00 per Trust Unit, being a conversion rate of 71.4286 Trust Units for each $1,000 principal amount of Debentures. No adjustment will be made for distributions on Trust Units issuable upon conversion or for interest accrued on Debentures surrendered for conversion; however, holders converting their Debentures will receive accrued and unpaid interest thereon. Notwithstanding the foregoing, no Debentures may be converted during the 5 Business Days preceding and including May 31 and November 30 and in each year, commencing May 31, 2004, as the registers of the Debenture Trustee will be closed during such periods.

Subject to the provisions thereof, the Debenture Indenture provides for the adjustment of the conversion price in certain events.

No fractional Trust Units will be issued on any conversion but in lieu thereof the Trust shall satisfy fractional interests by a cash payment equal to the current market price of any fractional interest.

The term "current market price" is defined in the Debenture Indenture to mean the weighted average trading price of the Trust Units on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the date fixed for redemption or the maturity date, as the case may be.

Redemption and Purchase

The Debentures are not redeemable on or before May 31, 2007. After May 31, 2007 and prior to maturity, the Debentures may be redeemed in whole or in part from time to time at the option of the Trust on not more than 60 days and not less than 30 days prior notice, at a Redemption Price of $1,050 per Debenture after May 31, 2007 and on or before May 31, 2008 and at a Redemption Price of $1,025 per Debenture after May 31, 2008 and before maturity, in each case, plus accrued and unpaid interest thereon, if any.

In the case of redemption of less than all of the Debentures, the Debentures to be redeemed will be selected by the Debenture Trustee on a pro rata basis or in such other manner as the Debenture Trustee deems equitable, subject to the consent of the TSX.

The Trust will have the right to purchase Debentures in the market, by tender or by private contract.

Payment upon Redemption or Maturity

On redemption or at maturity, the Trust will repay the indebtedness represented by the Debentures by paying to the Debenture Trustee in lawful money of Canada an amount equal to the aggregate Redemption Price of the outstanding Debentures which are to be redeemed or the principal amount of, and premium (if any) on, the outstanding Debentures which have matured, together with accrued and unpaid interest thereon. The Trust may, at its option, on not more than 60 days and not less than 40 days prior notice and subject to applicable regulatory approval, elect to satisfy its obligation to pay the Redemption Price of the Debentures which are to be redeemed or the principal amount of, and premium (if any) on, the Debentures which have matured, as the case may be, by issuing Trust Units to the holders of the Debentures. Any accrued and unpaid interest thereon will be paid in cash. The number of Trust Units to be issued will be determined by dividing the aggregate Redemption Price of the outstanding Debentures which are to be redeemed or the principal amount of, and premium (if any) on, the outstanding Debentures which have matured, as the case may be, by 95% of the current market price on the date fixed for redemption or the maturity date, as the case may be. No fractional Trust Units will be issued on redemption or maturity but in lieu thereof the Trust shall satisfy fractional interests by a cash payment equal to the current market price of any fractional interest.

Subordination

The payment of the principal of, and premium, if any, and interest on, the Debentures is subordinated in right of payment, as set forth in the Debenture Indenture, to the prior payment in full of all Senior Indebtedness of the Trust.

The Debenture Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to the Trust, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding-up of the Trust, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of the Trust or any sale of all or substantially all of the assets of the Trust, then those holders of Senior Indebtedness, including any indebtedness to trade creditors, will receive payment in full before the holders of Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Debentures or any unpaid interest accrued thereon. The Debenture Indenture will also provide that the Trust will not make any payment, and the holders of the Debentures will not be entitled to demand, institute proceedings for the collection of, or receive any payment or benefit (including, without any limitation, by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Debentures at any time when a default has occurred under the Senior Indebtedness and is continuing and the notice of such default has been given to the Debenture Trustee under the Debenture Indenture by the Trust, any holder of a Debenture or any holder of Senior Indebtedness, unless the Senior Indebtedness has been repaid in full. No holder of a Debenture has the right to institute any act or proceeding to enforce the Debentures in a manner inconsistent with the terms of the Debenture Indenture.

The Debentures are effectively subordinate to claims of creditors of the Trust's subsidiaries except to the extent the Trust is a creditor of such subsidiaries ranking at least *pari passu* with such other creditors. Specifically, the Debentures are subordinated in right of payment to the prior payment in full of all indebtedness under the Current Bank Facility.

Priority over Trust Distributions

The Trust Debenture Indenture provides that certain expenses of the Trust must be deducted in calculating the amount to be distributed to the Unitholders. Accordingly, the funds required to satisfy the interest payable on the Debentures, as well as the amount payable upon redemption or maturity of the Debentures or upon an Event of Default (as defined below), will be deducted and withheld from the amounts that would otherwise be payable as distributions to Unitholders.

Change of Control of the Trust

Within 30 days following the occurrence of a change of control of the Trust involving the acquisition of voting control or direction over 66⅔% or more of the Trust Units (a "**Change of Control**"), the Trust will be required to make an offer in writing to purchase all of the Debentures then outstanding (the "**Debenture Offer**"), at a price equal to 101% of the principal amount thereof plus accrued and unpaid interest (the "**Debenture Offer Price**").

The Debenture Indenture contains notification and repurchase provisions requiring the Trust to give written notice to the Debenture Trustee of the occurrence of a Change of Control within 30 days of such event together with the Debenture Offer. The Debenture Trustee will thereafter promptly mail to each holder of Debentures a notice of the Change of Control together with a copy of the Debenture Offer to repurchase all the outstanding Debentures.

If 90% or more of the aggregate principal amount of the Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered to the Trust pursuant to the Debenture Offer, the Trust will have the right and obligation to redeem all the remaining Debentures at the Debenture Offer Price. Notice of such redemption must be given by the Trust to the Debenture Trustee within 10 days following the expiry of the Debenture Offer, and as soon as possible thereafter, by the Debenture Trustee to the holders of the Debentures not tendered pursuant to the Debenture Offer.

Interest Payment Option

The Trust may elect, from time to time, to satisfy its obligation to pay interest on the Debentures (the "**Interest Obligation**"), on the date it is payable under the Debenture Indenture (an "**Interest Payment Date**"), by delivering sufficient Trust Units to the Debenture Trustee to satisfy all or any part of the Interest Obligation in accordance with the Debenture Indenture (the "**Unit Interest Payment Election**"). The Debenture Indenture will provide that, upon such election, the Debenture Trustee shall (a) accept delivery from the Trust of Trust Units, (b) accept bids with respect to, and consummate sales of, such Trust Units, each as the Trust shall direct in its absolute discretion, (c) invest the proceeds of such sales in short-term permitted government securities (as defined in the Debenture Indenture) which mature prior to the applicable Interest Payment Date, and use the proceeds received from such permitted government securities, together with any proceeds from the sale of Trust Units not invested as aforesaid, to satisfy the Interest Obligation, and (d) perform any other action necessarily incidental thereto.

The Debenture Indenture will set forth the procedures to be followed by the Trust and the Debenture Trustee in order to effect the Unit Interest Payment Election. If a Unit Interest Payment Election is made, the sole right of a holder of Debentures in respect of interest will be to receive cash from the Debenture Trustee out of the proceeds of the sale of Trust Units (plus any amount received by the Debenture Trustee from the Trust attributable to any fractional Trust Units) in full satisfaction of the Interest Obligation, and the holder of such Debentures will have no further recourse to the Trust in respect of the Interest Obligation.

Neither the Trust's making of the Unit Interest Payment Election nor the consummation of sales of Trust Units will (a) result in the holders of the Debentures not being entitled to receive on the applicable Interest Payment Date cash in an aggregate amount equal to the interest payable on such Interest Payment Date, or (b) entitle such holders to receive any Trust Units in satisfaction of the Interest Obligation.

Events of Default

The Debenture Indenture provides that an event of default ("**Event of Default**") in respect of the Debentures will occur if any one or more of the following described events has occurred and is continuing with respect of the Debentures: (a) failure for 10 days to pay interest on the Debentures when due; (b) failure to pay principal or premium, if any, when due on the Debentures, whether at maturity, upon redemption, by declaration or otherwise; (c) certain events of bankruptcy, insolvency or reorganization of the Trust under bankruptcy or insolvency laws; (d) default in the observance or performance of any material covenant or condition of the Debenture Indenture and continuance of such default for a period of 30 days after notice in writing has been given by the Debenture Trustee to the Trust specifying such default and requiring the Trust to rectify the same; (e) a resolution is passed for the liquidation or winding–up of the Trust; or (f) any proceedings are taken with respect to a compromise or arrangement of the Trust. If an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and shall upon request of holders of not less than 25% of the principal amount of Debentures then outstanding, declare the principal of and interest on all outstanding Debentures to be immediately due and payable. In certain cases, the holders of more than 50% of the principal amount of the Debentures then outstanding may, on behalf of the holders of all Debentures, waive any Event of Default and/or cancel any such declaration upon such terms and conditions as such holders shall prescribe.

Offers for Debentures

The Debenture Indenture contains provisions to the effect that if an offer is made for the Debentures which is a take-over bid for Debentures within the meaning of the *Securities Act* (Alberta) and not less than 90% of the Debentures (other than Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Debentures held by the holders of Debentures who did not accept the offer on the terms offered by the offeror.

Modification

The rights of the holders of the Debentures as well as any other series of debentures that may be issued under the Debenture Indenture may be modified in accordance with the terms of the Debenture Indenture. For that purpose, among others, the Debenture Indenture will contain certain provisions which will make binding on all Debenture holders resolutions passed at meetings of the holders of Debentures by votes cast thereat by holders of not less than 66⅔% of the principal amount of the Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66⅔% of the principal amount of the Debentures then outstanding. In certain cases, the modification will, instead or in addition, require assent by the holders of the required percentage of Debentures of each particularly affected series.

Limitation on Issuance of Additional Debentures

The Debenture Indenture provides that the Trust shall not issue additional convertible debentures of equal ranking if the principal amount of all issued and outstanding convertible debentures of the Trust exceeds 25% of the Total Market Capitalization of the Trust immediately after the issuance of such additional convertible debentures. "Total Market Capitalization" will be defined in the Debenture Indenture as the total principal amount of all issued and outstanding debentures of the Trust which are convertible at the option of the holder into Trust Units of the Trust plus the amount obtained by multiplying the number of issued and outstanding Trust Units of the Trust by the current market price of the Trust Units on the relevant date.

Limitation on Non-Resident Ownership

At no time may non-residents of Canada be the beneficial owners of a majority of the Trust Units, on a fully diluted basis, including any Trust Units which may be issued upon conversion, redemption or maturity of the Debentures. The Trustee may require declarations as to the jurisdictions in which beneficial owners of the Debentures are resident. If the Trustee becomes aware as a result of requiring such declarations as to beneficial ownership, that the beneficial owners of 49% of the Trust Units then outstanding, on a fully diluted basis, are, or may be, non-residents of Canada or that such a situation is imminent, the Trustee may make a public announcement thereof and shall not register a transfer of Debentures to a person unless the person provides a declaration that the person is not a non-resident. If, notwithstanding the foregoing, the Trustee determines that a majority of the Trust Units are held by non-residents of Canada, the Trustee may send a notice to non-resident holders of Debentures, chosen in inverse order to the order of acquisition or registration of the Debentures or in such manner as the Trustee may consider equitable and practicable, requiring them to sell their Debentures or a portion thereof within a specified period of not less than 60 days. If the Debenture holders receiving such notice have not sold the specified number of Debentures or provided the Trustee with satisfactory evidence that they are not non-residents within such period, the Trustee may, on behalf of such Debenture holder, sell such Debentures, and, in the interim, shall suspend the rights attached to such Debentures. Upon such sale, the affected holders shall cease to be holders of Debentures, and their rights shall be limited to receiving the net proceeds of sale upon surrender of such Debentures. The trustees of the Trust have similar obligations in respect of the Trust Units which are outlined in the Trust Debenture Indenture.

TRUST UNIT INCENTIVE PLAN

The Trust has adopted the Unit Incentive Plan which permits the Harvest Board to grant non-transferable rights to purchase Trust Units ("Incentive Rights") to the directors, officers, consultants, employees and other ongoing service providers of the Trust and its subsidiaries, including the Corporation. The purpose of the Unit Incentive Plan is to provide an effective long term incentive to eligible participants and to reward them on the basis of long term performance and distributions. Effective June 12, 2003 the total number of Trust Units issuable under the Unit Incentive Plan was increased from 875,000 Trust Units to a cumulative maximum number of 1,121,000 Trust Units. The total number of Trust Units issuable under the Unit Incentive Plan as at April 30, 2004 was 1,063,725.

The Harvest Board administers the Unit Incentive Plan and determines participants in the Unit Incentive Plan, numbers of Incentive Rights granted, and the terms of vesting of Incentive Rights. The grant price of the Incentive Rights (the "Grant Price") shall be equal to the per Trust Unit closing price on the trading date immediately preceding the date of grant, unless otherwise permitted. The exercise price ("Exercise Price") per Right shall be calculated by deducting from the Grant Price the aggregate of all distributions, on a per Unit basis, made by the Trust after the Grant Date, provided the aggregate amount of such distribution represents a return of more than 0.833% of the Trust's recorded cost of capital assets less all debt, working capital deficiency (surplus) or debt equivalent instruments, depletion, depreciation and amortization charges and any future income tax liability associated with such capital assets at the end of each month.

Incentive Rights are exercisable for a maximum of five years from the date of the grant thereof and are subject to early termination upon the holder ceasing to be an eligible participant, or upon the death of the holder. In the case of early termination, a holder is entitled, from the date the holder ceased to be an eligible participant to the earlier of 30 days and the end of the exercise period, to exercise vested Incentive Rights. In the case of death, the estate of the holder is entitled, from the date of death to the earlier of 6 months and the end of the exercise period, to exercise vested Incentive Rights at the Exercise Price in effect at the date of death. Incentive Rights not vested at the date of termination of the holder or at date of the holder's death are immediately null and void. The Trust has the option to settle outstanding Incentive Rights with Trust Units and/or cash. The number of Trust Units to be issued to settle outstanding Incentive Rights shall equal the amount determined by multiplying the number of Incentive Rights by the quotient obtained by dividing the difference between the current market price of a Trust Unit and the Exercise Price by the current market price of a Trust Unit. Cash paid to settle outstanding Incentive Rights will equal the difference between the current market price of a Trust Unit less the Exercise Price multiplied by the number of Incentive Rights to be settled.

The following table sets forth information with respect to the Incentive Rights outstanding under the Unit Incentive Plan as at April 30, 2004.

Group	Date Incentive Rights Granted	Trust Units Under Option	Grant Price	Closing Price on Day Prior to Grant	Exercise Price as at April 30, 2004	Expiry Date	Market Value of Incentive Right [(1)]
Executive Officers (5)	November 25, 2002	475,000	$8.00	$8.00	$4.80	November 25, 2007	$4,797,000
	February 14, 2003	9,500	$10.75	$10.75	$7.85	February 14, 2008	$66,975
Directors (4)	November 25, 2002	75,000	$8.00	$8.00	$4.80	November 25, 2005	$757,500
	February 14, 2003	25,000	$10.75	$10.75	$7.85	February 14, 2008	$176,250
Employees and Consultants (46)	November 25, 2002	231,250	$8.00	$8.00	$4.80	November 25, 2005	$2,335,625
	January 24, 2003	18,125	$10.21	$10.21	$7.16	January 24, 2008	$140,324
	July 15, 2003	12,500	$10.18	$10.18	$8.29	July 15, 2008	$82,625
	July 17, 2003	7,500	$10.30	$10.30	$8.41	July 17, 2008	$48,675
	July 18, 2003	11,000	$10.45	$10.45	$8.56	July 18, 2008	$69,740
	October 17, 2003	73,400	$12.19	$12.19	$10.89	October 17, 2008	$294,040
	December 15, 2003	99,750	$13.15	$13.15	$12.24	December 15, 2008	$265,335
	February 16, 2004	13,700	$13.35	$13.35	$12.87	February 16, 2009	$493,710
	February 24, 2004	12,000	$13.75	$13.75	$13.33	February 24, 2009	$974,896

Note:

(1) Based on the difference between the closing price of $14.90 per Trust Unit on the TSX on April 30, 2004 and the grant price of the Incentive Right less distributions per Trust Unit paid after the date the Incentive Right was granted multiplied by the number of Trust Units under the Incentive Right.

DRIP PLAN

The Trust has received all applicable regulatory approvals and has implemented a DRIP Plan. **The DRIP Plan is not available to Unitholders who are residents of the United States.** The DRIP Plan provides eligible holders of Trust Units the means of accumulating additional Trust Units by reinvesting any Distributable Cash received. At the discretion of the Corporation, Trust Units will either be acquired at prevailing market rates (not exceeding 115% of the volume weighted average trading price of the Trust Units on the TSX for the 10 trading days immediately preceding the date the Trust Units are purchased) or issued from treasury at 95% of the market price of the Trust Units (calculated as the weighted average trading price of the Trust Units on the TSX for the period commencing on the second Business Day following the distribution record date and ending on the second Business Day immediately prior to the distribution payment date on which at least a board lot of Trust Units is traded). Participants in the DRIP Plan are also permitted to purchase additional Trust Units at 100% of the market price (as described above) of the Trust Units by investing additional sums to a maximum of $5,000 per month and a minimum of $1,000 per remittance; provided that the total number of Trust Units that may be issued each fiscal year pursuant to optional cash payments is restricted to not more than 2% of the number of issued and outstanding Trust Units at the commencement of that year. As at April 30, 2004, 1,125,675 Trust Units have been issued from treasury since February 15, 2003 for proceeds of approximately $12.2 million due to DRIP Plan participation associated with cash distributions by the Trust.

CONFLICTS OF INTEREST

Properties will not be acquired from officers or directors of the Corporation or persons not at arm's length with such persons at prices which are greater than fair market value, nor will Properties be sold to officers or directors of the Corporation or persons not at arm's length with such persons at prices which are less than fair market value in each case as established by an opinion of an independent financial advisor and approved by the independent members of the Harvest Board. There may be circumstances where certain transactions may also require the preparation of a formal valuation and the affirmative vote of Unitholders in accordance with the requirements of Ontario Securities Commission Rule 61-501.

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

SELECTED FINANCIAL INFORMATION

Annual and Financial Information

The following is a summary of selected consolidated financial information of the Trust for the period from July 10 to December 31, 2002 and the three month period ended on each of March 31, 2003, June 30, 2003, September 30, 2003 and December 31, 2003. The following should be read in conjunction with the information contained under the heading "Management's Discussion and Analysis" below and the audited consolidated financial statements of the Trust for the year ended December 31, 2003 and the audited consolidated financial statements of the Trust for the period from July 10, 2002 to December 31, 2002. The selected consolidated financial information is not necessarily reflective of the Trust's future results from operations or financial condition.

	For the period	2003			
($000, except unit amounts)	from July 10 to December 31, 2002	Three month period ended March 31	Three month period ended June 30	Three month period ended September 30	Three month period ended December 31
Net Revenue	8,955	14,738	17,622	21,181	30,474
Net Income	5,136	3,736	1,180	5,751	6,043
Net Income per unit - basic	3.46	0.36	0.10	0.46	0.37
Net Income per unit - diluted	3.69	0.34	0.10	0.45	0.36
Total Assets	93,729	92,041	120,122	144,369	220,250
Total Liabilities	53,723	38,891	61,645	51,473	89,175
Distributions declared, per unit	0.20	0.60	0.60	0.60	0.60

RECORD OF CASH DISTRIBUTIONS

The following table sets forth the per Trust Unit amount of monthly cash distributions paid by the Trust since the completion of the Initial Public Offering.

2003	Distribution Per Trust Unit
January [(1)]	$0.20
February	$0.20
March	$0.20
April	$0.20
May	$0.20
June	$0.20
July	$0.20
August	$0.20
September	$0.20
October	$0.20
November[(2)]	$0.20
December	$0.20
2004	
January	$0.20
February	$0.20
March	$0.20

Notes:

(1) This distribution was the first cash distribution paid by the Trust following the completion of the Initial Public Offering.

(2) The Trust announced on April 15, 2004 that the next monthly cash distribution of $0.20 per Trust Unit will be paid on May 17, 2004 to Unitholders of record on April 30, 2004.

Unitholders of record on a Record Date will be entitled to receive monthly cash distributions of the Distributable Cash which will become payable on the 15th day following the Record Date, and if such date of payment is not a Business Day on the next Business Day after the 15th day following the Record Date.

ESCROWED SECURITIES

In connection with the completion of the Initial Public Offering, certain members of the Management Group holding an aggregate $4,777,500 principal amount of debentures of 990148 Alberta Ltd. (which were settled with 4,777,500 Trust Units which, as at September 30, 2003 represented approximately 38.4% of the then outstanding Trust Unit and as at the date hereof approximately 28.1%) executed an undertaking in favour of the underwriters of the Initial Public Offering not to offer or sell, agree to offer or sell, or enter into an arrangement to offer or sell any Trust Units or other securities of the Trust or the Corporation, or securities convertible into, exchangeable for, or otherwise exercisable to acquire any securities of the Trust or the Corporation then held by such holder or such holder's spouse, directly or indirectly, at any time until November 28, 2004.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Reference is made to the "Management's Discussion and Analysis" for the year ended December 31, 2003 contained on pages 23 to 35 of the Trust's 2003 Annual Report, which is incorporated herein by reference. The Management's Discussion and Analysis should be read in connection with the audited consolidated financial statements of the Trust for the year ended December 31, 2003 which are included in the Trust's 2003 Annual Report and which are incorporated herein by reference.

MARKET FOR SECURITIES

The Trust Units are listed and traded on the TSX. The trading symbol for the Trust Units is HTE.

RISK FACTORS

The following are certain factors relating to the business of the Trust. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form.

Public and Insider Ownership

As at April 30, 2004, the directors and officers of the Corporation and their associates and affiliates, as a group, held, directly or indirectly, or exercised control or direction over, approximately 6,555,831 Trust Units or approximately 37.9% of the outstanding Trust Units.

As part of the Initial Public Offering, certain members of the Management Group holding an aggregate $4,777,500 principal amount of the Management Group Debentures executed an undertaking in favour of the Underwriters not to offer or sell, agree to offer or sell, or enter into an arrangement to offer or sell any Trust Units or other securities of the Trust or the Corporation, or securities convertible into, exchangeable for, or otherwise exercisable to acquire any securities of the Trust or the Corporation then held by such holder or such holder's spouse, directly or indirectly, at any time until November 28, 2004.

Dilution

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Harvest Board may determine. In addition, the Trust may issue additional Trust Units from time to time pursuant to the Unit Incentive Plan and the DRIP Plan. The possible issuance of these Trust Units could result in dilution to holders of Trust Units. See "Trust Indenture – Issuance of Trust Units", "Trust Unit Incentive Plan" and "DRIP Plan".

Purchase of the NPI, the Properties and the Direct Royalties

The price paid for the purchase of the NPI, the Provost Properties and the Direct Royalties or to be paid for the purchase of the Carlyle Properties was based on engineering and economic assessments made by independent engineers. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of crude oil, natural gas and natural gas liquids, future prices of oil, natural gas and natural gas liquids and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation and the Trust. In particular, changes in the prices of and markets for petroleum, natural gas and natural gas liquids from those anticipated at the time of making such assessments will affect the return on the value of the Trust Units. In addition, all such assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than those currently attributed to the Provost Properties and the Carlyle Properties.

Changes in Legislation

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

Investment Eligibility

If the Trust ceases to qualify as a mutual fund trust, the Trust Units will cease to be qualified investments for registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), deferred profit sharing plans ("DPSPs") and registered education savings plans ("RESPs") (collectively, "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 or any gains realized on a disposition of the Trust Units while they are not qualified investments. See "Eligibility for Investment" and "Canadian Federal Income Tax Considerations".

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 the Corporation and possible liability to third parties. The Corporation will employ prudent risk management practices and 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. The Corporation 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 income from the NPI.

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 the Corporation operates the Provost Properties and believes it will become the operator of the Carlyle Properties, there is no guarantee that it will remain operator of the Provost Properties or that the Corporation will operate the Carlyle Properties or any other Properties it may acquire.

A significant portion of the operating expenses of the Provost Properties, and to a lesser degree, the Carlyle Properties, is attributable to electrical power costs. Since deregulation of the electrical power system in Alberta in recent years, the unit cost of electrical power has been set by a market driven mechanism based upon supply and demand. As a result, the prices for electrical power have become volatile. This volatility in electrical power pricing can impact the Corporation's operating expenses, and in turn, the Cash Available For Distribution. The Corporation has implemented an electrical power hedging program to mitigate its exposure to electrical power cost volatility. In respect of the Carlyle Properties, the Saskatchewan power system is regulated and as such, electrical power costs are not subject to significant volatility. However, there can be no certainty that the Saskatchewan power system will not deregulate in the future.

Although satisfactory title reviews will generally be conducted on the Properties in accordance with industry standards, such reviews do not guarantee or certify that a defect in title may not arise to defeat the claim of the Corporation to certain Properties. A reduction of income from the NPI or income from Direct Royalties could result in such circumstances.

Reserve Estimates

The reserve and recovery information contained in the McDaniel Report is only an estimate and the actual production and ultimate reserves from the Properties may differ from the estimates prepared by McDaniel.

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 the issuance of clean up orders in respect of the Corporation or the Properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on the Corporation. See "Industry Conditions – Environmental Regulation". Although the Operating Subsidiaries have established reclamation funds for the purpose of funding estimated future environmental and reclamation obligations, there can be no assurance that the Operating Subsidiaries will be able to satisfy its actual environmental and reclamation obligations. See "Description of the Trust – The NPI and Direct Royalties – Reclamation Fund".

In December 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 levels during the period between 2008 and 2012. The Protocol will only become legally binding when it is ratified by at least 55 countries, covering at least 55 percent of the emissions addressed by the Protocol. If the Protocol is ratified and becomes legally binding, it is expected to affect the operation of all industries in Canada, including the oil and natural gas industry. As details of the implementation of this Protocol have yet to be announced, it is difficult to determine what, if any, the impact the Protocol may have on the Corporation's ongoing environmental liabilities, on prices for oil and natural gas or on other general economic factors, which may affect the Trust's Cash Available For Distribution.

Debt Service

As at the date hereof, the Trust had indebtedness of approximately $64 million under the Current Bank Facility. In addition, the New Lender has issued letters of credit to third parties of approximately $3.3 million on behalf of the Corporation to secure services on the Properties. See "Information Respecting the Corporation – Borrowing by the Corporation". In addition, as of the date hereof, approximately $25 million is outstanding under the Equity Bridge Notes. See "Description of the Trust – Borrowing by the Trust.

The Current Lender was provided with security over all of the assets of the Operating Subsidiaries. See "Information Respecting the Corporation – Borrowing by the Corporation". If the Corporation, WEI and the Trust experience an unremedied borrowing base shortfall or default, commit an event of default or the Current Lender demands repayment, the Current Lender may foreclose on or sell the Properties free from, or together with, the NPI.

Dividends and other distributions by the Corporation are prohibited in certain circumstances upon a borrowing base shortfall or default, or upon an event of default or demand for repayment under the Current Bank Facility. The NPI, any indebtedness of the Corporation to the Trust, and amounts payable to the Trustee under the Trust Indenture are subordinate to the Current Bank Facility pursuant to a subordination agreement between the Current Lender, the Trustee, and the Corporation dated October 16, 2002. This Subordination Agreement may restrict the ability of the Corporation to pay the NPI to the Trust or pay interest or principal on any indebtedness to the Trust, and therefore may limit or eliminate the Cash Available For Distribution.

The Corporation must meet certain ongoing hedging and financial covenants under the Current Bank Facility. The covenants are customary restrictions on the Corporation's operations and activities, including restrictions on the incurring of indebtedness, the granting of security, the issuance of incremental debt, and the sale of its assets.

Debt Repayment

The Corporation and the Trust are permitted to borrow funds to finance the purchase of Properties, capital expenditures, or other financial obligations in respect of the Properties or for working capital purposes. Borrowings of the Corporation to fund the purchase of Canadian resource properties may be repaid with funds received from the Trust. Debt service costs of the Operating Subsidiaries are deducted in computing income from the NPI and debt service costs of the Trust are deducted in computing Cash Available For Distribution. Variations in interest rates could result in significant changes in the amount required to be applied to debt service before payment of the NPI and Cash Available For Distribution. To the extent that borrowings under the New Interim Bank Facility are made in U.S. dollars, the interest payable thereunder is also payable in U.S. dollars. Variations in the Canadian/U.S. dollar exchange could result in a significant increase in the amount of the interest paid under the New Interim Bank Facility, thereby reducing the Cash Available For Distribution. See "Information Respecting the Corporation – Borrowing by the Corporation".

Delay in Cash Distributions

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the Properties, and by the operator to the Corporation, 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 operator of expenses incurred in the operation of Properties or the establishment by the operator of reserves for such expenses.

Variability of Cash Distributions

The Operating Subsidiaries retain a portion of the cash flows from the Properties in their Reserve Fund to facilitate future acquisitions and development of the Properties. The Corporation believes this will assist in maintaining distributions for a longer period than would otherwise be the case if all cash flows from the Properties were paid to the Trust pursuant to the NPI and subsequently distributed to the Unitholders. Future cash flows generated by such additional Properties may not be similar to those of the Provost Properties and may not generate sufficient cash flows to allow the Operating Subsidiaries to generate sufficient income from the NPI to allow the Trust to maintain consistent distributions from the Trust over a long period of time.

Reliance on Management of the Corporation

Unitholders will be dependent on the management of the Corporation in respect of the administration and management of all matters relating to the Properties, the NPI, the Direct Royalties, the Trust, and the Trust Units. Investors who are not willing to rely on the management of the Corporation should not invest in the Trust Units.

Depletion of Reserves (Sustainability)

The Trust has certain unique attributes which differentiate it from other oil and natural gas industry participants. Cash Available For Distribution 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 the Corporation will not be reinvesting cash flow in the same manner as other industry participants. Accordingly, absent additional capital investment in Properties through the use of the Capital Fund or otherwise, initial production levels and reserves attributable to the Properties will decline.

The Corporation's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on the Corporation's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are exploited.

Trust Units will have no value when reserves from the Properties can no longer be economically marketed and, as a result, subscribers for Trust Units will need to obtain a return of capital invested out of cash flow derived from their investment in Trust Units during the period when reserves can be economically recovered.

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

There can be no assurance that the Corporation will be successful in developing or acquiring additional reserves on terms that meet the Corporation's investment objectives.

Return of Capital

Trust Units will have no value when reserves from the underlying assets of the Trust can no longer be economically produced and, as a result, cash distributions do not represent a "yield" in the traditional sense as they represent both return of capital and return on investment.

Additional Financing

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

Limited Operational History

The Corporation and the Trust were only recently organized and have a limited history of operations and the Trust has made only limited distributions.

Impact of Future Capital Expenditures

The Reserve Value of the Properties as estimated by McDaniel is based in part on cash flows to be generated in future years as a result of future capital expenditures. The Reserve Value of the Properties as estimated by McDaniel will be reduced to the extent that such capital expenditures on the Properties do not achieve the level of success assumed by McDaniel.

Volatility of Commodity Prices and Foreign Exchange Risk

The Trust's results of operations and financial condition, and therefore the NPI and the Direct Royalties, will be dependent on the prices received for petroleum, natural gas and natural gas liquids production. Prices for petroleum, natural gas and natural gas liquids have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil producing regions, which are beyond the control of the Corporation or the Trust. Oil prices received from production in Canada also reflect changes in the Canadian/U.S. currency exchange rate. Any decline in petroleum oil and natural gas prices or increases in differentials could have a material adverse effect on the Trust's operations, financial condition and the level of funds available for the development of its oil and natural gas reserves. The Corporation may manage the risk associated with changes in commodity prices and foreign exchange rates by entering, or causing the Trust to enter, from time to time, into crude oil and natural gas price hedges and foreign exchange contracts. To the extent that the Corporation or the Trust engages in risk management activities related to commodity prices and foreign exchange rates, it will be subject to counterparty risk. In addition, commodity hedge contracts may require, from time to time, margin payments to be made which could impact negatively on the Trust's ability to make distributions to Unitholders. The Corporation must also meet certain ongoing hedging covenants under its credit facility. To the extent that commodity prices increase significantly, Cash Available for Distribution could be negatively affected.

Crude Oil Differentials

The Corporation's crude oil production from the Properties will be approximately 73% light and medium oil, 26% heavy oil and 1% natural gas and natural gas liquids. Processing medium oil and heavy oil is more expensive than processing conventional light oil, and such processing yields less valuable products compared to refining light oil; accordingly, producers of heavy oil or medium oil receive lower wellhead prices. The differential between light oil and heavy oil or medium oil has fluctuated widely during recent years and when considered with the fluctuating prices of light oil, substantially increases the volatility of prices for heavy oil and medium oil. Any increase in the differentials could result in lower prices being received for petroleum, natural gas and natural gas liquids and could have a material adverse effect on the Trust's operations, financial condition and the level of funds available for the development of its oil and natural gas reserves. Volatility in the differential is a result of an availability of supply, seasonal demand, pipeline constraints and conversion capacity of refineries, which are beyond the control of the Trust or the Corporation.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. The Corporation and the Trust will actively compete for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation and the Trust. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

Potential Conflicts of Interest

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

Nature of Trust Units

Securities such as the Trust Units are hybrids in that they share certain attributes common to both equity securities and debt instruments. Trust Units are dissimilar to debt instruments in that there is no principal amount owing to Unitholders. 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 the Corporation. 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 NPI, the Direct Royalties and related contractual rights. The market price per Trust Unit will be a function of anticipated Cash Available For Distribution, the value of the Properties acquired by the Corporation and the Corporation's ability to effect long-term growth in the value of the Trust. The issue price of each Trust Unit is greater than the per Trust Unit Reserve Value of the Provost Properties. The market price of the Trust Units will be 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.

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust Fund or the obligations or affairs of the Trust or with respect to any act performed by the Trustee or by any other person pursuant to the Trust Indenture or with respect to any act or omission of the Trustee or any other person in the performance or exercise, or purported performance or exercise, of any obligation, power, discretion or authority conferred upon the Trustee or such other person hereunder or with respect to any transaction entered into by the Trustee or by any other person pursuant to the Trust Indenture. No Unitholder shall be liable to indemnify the Trustee or any such other person with respect to any such liability or liabilities incurred by the Trustee or by any such other person or persons or with respect to any taxes payable by the Trust or by the Trustee or by any other person on behalf of or in connection with the Trust. Notwithstanding the foregoing, to the extent that any Unitholders are found by a court of competent jurisdiction to be subject to any that liability, such liability shall be enforceable only against, and shall be satisfied only out of, the Trust Fund, and the Trust (to the extent of the Trust Fund) is liable to, and shall indemnify and save harmless any Unitholder against any costs, damages, liabilities, expenses, charges or losses suffered by any Unitholder from or arising as a result of such Unitholder not having any such limited liability.

The Trust Indenture also provides that all contracts signed by or on behalf of the Trust, whether by the Corporation, the Trustee, or otherwise, must (except as the Trustee or the Corporation may otherwise expressly agree with respect to their own personal liability) contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of the Trust to the same extent a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against the Trust (to the extent that claims are not satisfied by 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 to Unitholders of this nature arising is considered unlikely by the Harvest Board in view of the fact that all business operations are carried on by the Corporation.

The activities of the Trust and the Corporation, its wholly-owned subsidiary, are conducted and are intended to be 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 to the Unitholders for claims against the Trust including by obtaining appropriate insurance, where available, for the operations of the Corporation and having contracts signed by or on behalf of the Trust include a provision that such obligations are not binding upon Unitholders personally.

Net Asset Value

The net asset value of the Trust will vary dependent upon a number of factors beyond the control of management, including oil and natural gas prices. The trading prices of the Trust Units is also determined by a number of factors which are beyond the control of management and such trading prices may be greater than or less than the net asset value of the Trust.

Change in the Trust's Status Under Tax Laws

Harvest presently qualifies as a mutual fund trust for purposes of the Tax Act and it is intended that the Trust continue to qualify as a mutual fund trust for such purposes; however, should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise. The material consequences of losing mutual fund trust status are as follows: (i) Trust Units would not constitute qualified investments for Exempt Plans upon the Trust ceasing to be a mutual fund trust. 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 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. An RRSP or RRIF holding Trust Units that are not qualified investments would become taxable n income attributable to the Trust Units while they are not qualified investments. RESPs which hold Trust Units that are not qualified investments may have their registration revoked by the Canada Customs and Revenue Agency; (ii) the Trust would be required to pay a tax under Part XII.2 of the Tax Act on certain types of income distributed to unitholders including income generated by oil and natural gas royalties held by the Trust. The payment of the Part XII.2 tax by the Trust may have adverse income tax consequences for certain Unitholders, since the amount of cash available for distribution would be reduced by the amount of the tax; (iii) the Trust would cease being eligible for the capital gains refund mechanism available under the Tax Act upon ceasing to be a mutual fund trust; (iv) Trust Units held by Unitholders that are not residents of Canada would become taxable Canadian property upon the Trust ceasing to be a mutual fund trust. Such Unitholders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units constituting taxable Canadian property; and (v) the Trust would be subject to alternative minimum tax under Part I of the Tax Act.

Structure of the Trust

From time to time, the Trust may take steps to organize its affairs in a manner which minimizes taxes and other expenses payable with respect to the operation of the Trust and the Operating Subsidiaries and which maximizes the amount of cash available for distributions to Unitholders. If the manner in which the Trust structures its affairs is successfully challenged by a taxation or other authority, the amount of cash available for distribution to Unitholders may be affected.

ADDITIONAL INFORMATION

Additional information including remuneration of directors and officers of the Corporation, principal holders of the Trust Units, is contained in the Information Circular - Proxy Statement of the Trust dated May 12, 2004 which relates to the Annual and Special Meeting of Unitholders to be held on June 22, 2004, and additional financial information is provided in the consolidated financial statements of the Trust for the year ended December 31, 2003.

The Trust shall provide to any person, upon request to the Secretary of the Corporation 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,

(b) 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;

(c) one copy of the consolidated financial statements of the Trust for the most recently completed fiscal year together with the accompanying report of the auditor and one copy of any subsequent interim financial statements;

(d) one copy of the Information Circular - Proxy Statement of the Trust dated May 12, 2004; and

(e) 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; or

(f) 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:

Harvest Energy Trust
c/o Harvest Operations Corp.
1900, 330 – 5th Avenue S.W.
Calgary, Alberta T2P 0L4
Toll free in Canada: 1-866-666-1178
Fax: (403) 265-3940

APPENDIX A
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Harvest Operations Corp. (the "Company") on behalf of Harvest Energy Trust (the "Trust") are responsible for the preparation and disclosure of information with respect to the Company's and the Trust's other subsidiaries' oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(g) (i) proved and proved plus probable oil and natural gas reserves estimated as at December 31, 2003 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(h) (i) proved oil and natural 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 has evaluated the Company's and the Trust's other subsidiaries' reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves, Safety & Environment Committee (the "RSE Committee") of the board of directors of the Company has

(i) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(j) 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

(k) reviewed the reserves data with management and the independent qualified reserves evaluator.

The RSE Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Audit Committee, approved

(l) the content and filing with securities regulatory authorities of the reserves data and other oil and natural gas information;

(m) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(n) the content and filing of this report.

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

(signed) "Jacob Roorda"
Jacob Roorda
President

(signed) "J. A. Ralston"
J. A. Ralston
Vice President, Operations

(signed) "Verne Johnson"
Verne Johnson
Director and Chairman of the RSE Committee

(signed) "Hank B. Swartout"
Hank B. Swartout
Director and Member of the RSE Committee

April 30, 2004

APPENDIX B
REPORT ON RESERVES DATA

To the board of directors of Harvest Operations Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2003. The reserves data consist of the following:

   (a) proved and proved plus probable oil and natural gas reserves estimated as at December 31, 2003 using forecast prices and costs and the related estimated future net revenue; and

   (b) proved oil and natural gas reserves estimated as at December 31, 2003 using constant prices and costs; and the related estimated future net revenue.

2. The reserves data are the responsibility of the Company'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 Company evaluated by us for the year ended December 31, 2003, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management:

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
December 31, 2003	Canada	-	169,171	-	169,171

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.

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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.

McDaniel & Associates Consultants Ltd.

(signed) "B.H. Emslie, P.Eng."
Senior Vice President

Calgary, Alberta
April 30, 2004

APPENDIX C
FINANCIAL STATEMENTS

1. Schedule of Revenue and Expenses for certain of the Provost Properties Acquired from Devon Canada Corporation – Years Ended December 31, 2001, 2000 and 1999 and Six Months Ended June 30, 2002 and 2001.

2. Schedule of Revenue and Expenses for certain of the Provost Properties Acquired from Anadarko Canada Corporation – Years Ended December 31, 2001, 2000 and 1999 and Six Months Ended June 30, 2002 and 2001.

3. Schedule of Revenue and Expenses for the Carlyle Properties – Years Ended December 31, 2002, 2001 and 2000 and Nine Months Ended September 30, 2003 and 2002.

4. Pro Forma Consolidated Financial Statements of Harvest Energy Trust as at and for the Year Ended December 31, 2003.

kpmg

Schedule of Revenue and Expenses for the

INITIAL PROPERTIES

Acquired from Devon Canada Corporation

Years ended December 31, 2001, 2000 and 1999

AUDITORS' REPORT

To the board of directors of Harvest Operations Corp.

At the request of Harvest Operations Corp., we have audited the schedule of revenue and expenses for the properties (the "Initial Properties") referred to in the purchase and sale agreement dated May 28, 2002 between Harvest Operations Corp. and Devon Canada Corporation and Devon ARL Corporation for each of the years in the three year period ended December 31, 2001. This financial information is the responsibility of Harvest Operations Corp. Our responsibility is to express an opinion on this financial information based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial information is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial information. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial information.

In our opinion, this financial information presents fairly, in all material respects, the revenue and expenses for the Initial Properties referred to in the purchase and sale agreement dated May 28, 2002 for each of the years in the three-year period ended December 31, 2001.

(signed) KPMG LLP

Chartered Accountants

Calgary, Canada
September 18, 2002

INITIAL PROPERTIES

Schedule of Revenue and Expenses for the Initial Properties

	Six months ended June 30,		Years ended December 31,		
	2002	2001	2001	2000	1999
	(unaudited)		(audited)		
Revenue	$ 13,935,019	$ 16,772,213	$ 30,675,360	$ 46,395,299	$ 30,506,217
Royalties	(1,210,816)	(1,630,888)	(2,791,810)	(4,406,652)	(2,984,815)
	12,724,203	15,141,325	27,883,550	41,988,647	27,521,402
Operating costs	5,050,362	6,901,821	11,587,364	9,333,045	7,266,639
Operating income	$ 7,673,841	$ 8,239,504	$ 16,296,186	$ 32,655,602	$ 20,254,763

See accompanying notes to schedule of revenue and expenses for the Initial Properties.

1. Basis of presentation:

On May 28, 2002 Harvest Operations Corp. entered into a purchase and sale agreement to acquire the Thompson Lake properties (the "Initial Properties") from Devon Canada Corporation and Devon ARL Corporation (collectively "Devon Canada"). This acquisition closed on July 10, 2002.

The schedule of revenue and expenses for the Initial Properties includes the operations of the Initial Properties by Devon Canada.

The schedule of revenue and expenses for the Initial Properties includes only amounts applicable to the working interest of Devon Canada for the Initial Properties.

The schedule of revenue and expenses for the Initial Properties does not include any provision for the depletion and depreciation, site restoration, future capital costs, impairment of unevaluated properties, general and administrative costs and income taxes for the Initial Properties as these amounts are based on the consolidated operations of Devon Canada of which the Initial Properties formed only a part.

2. Significant accounting policies:

(a) Revenue:

Revenue from the sale of oil and natural gas is recorded at the time that the product is produced and sold.

(b) Royalties:

Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with Alberta Energy regulations or the terms of individual royalty agreements.

(c) Operating expenses:

Operating expenses include amounts incurred to bring the oil and natural gas to the surface, gather, transport, field process, treat and store same. Operating expenses are reflected net of gathering, processing and transportation revenue associated with the Initial Properties.

Schedule of Revenue and Expenses for the

ADDITIONAL PROPERTIES

Acquired from Anadarko Canada Corporation

Years ended December 31, 2001, 2000 and 1999

AUDITORS' REPORT

To the board of directors of Harvest Operations Corp.

At the request of Harvest Operations Corp., we have audited the schedule of revenue and expenses for the Additional Properties referred to in the purchase and sale agreement dated August 1, 2002 between Harvest Operations Corp. and Anadarko Canada Corporation for each of the years in the three-year period ended December 31, 2001. This financial information is the responsibility of Harvest Operations Corp. Our responsibility is to express an opinion on this financial information based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial information is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial information. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial information.

In our opinion, this financial information presents fairly, in all material respects, the revenue and expenses for the Additional Properties referred to in the purchase and sale agreement dated August 1, 2002 for each of the years in the three-year period ended December 31, 2001.

(signed) KPMG LLP

Chartered Accountants

Calgary, Canada
September 18, 2002

ADDITIONAL PROPERTIES

Schedule of Revenue and Expenses for the Additional Properties

	Nine months ended September 30,		Years ended December 31,		
	2002	2001	2001	2000	1999
	(unaudited)		(audited)		
Revenue	$ 55,459,785	$ 48,198,918	$ 57,615,104	$ 72,026,276	$ 42,693,456
Royalties	(7,323,940)	(7,860,337)	(11,340,031)	(14,465,051)	(7,268,179)
	48,135,845	40,338,581	46,275,073	57,561,225	35,425,277
Operating costs	12,665,536	10,404,008	12,832,174	8,799,976	7,452,752
Operating income	$ 35,470,309	$ 29,934,573	$ 33,442,899	$ 48,761,249	$ 27,972,525

See accompanying notes to schedule of revenue and expenses for the Additional Properties.

1. Basis of presentation:

On August 1, 2002, Harvest Operations Corp. entered into a purchase and sale agreement to acquire the Hayter and Provost properties (the "Additional Properties") from Anadarko Canada Corporation ("Anadarko"). This acquisition closed on November 15, 2002.

The schedule of revenue and expenses for the Additional Properties includes the operations of the Additional Properties by Anadarko.

The schedule of revenue and expenses for the Additional Properties includes only amounts applicable to the working interest of Anadarko for the Additional Properties.

The schedule of revenue and expenses for the Additional Properties does not include any provision for the depletion and depreciation, site restoration, future capital costs, impairment of unevaluated properties, general and administrative costs and income taxes for the Additional Properties as these amounts are based on the consolidated operations of Anadarko of which the Additional Properties form only a part.

2. Significant accounting policies:

(a) Revenue:

Revenue from the sale of oil and natural gas is recorded at the time that the product is produced and sold.

(b) Royalties:

Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with Alberta Energy regulations or the terms of individual royalty agreements.

(c) Operating expenses:

Operating expenses include amounts incurred to bring the oil and natural gas to the surface, gather, transport, field process, treat and store same and variable operating overhead as established by Anadarko.

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Schedule of Revenue and Expenses for the

CARLYLE PROPERTIES

Years ended December 31, 2002, 2001 and 2000

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AUDITORS' REPORT

To the board of directors of Harvest Operations Corp.

At the request of Harvest Operations Corp., we have audited the schedule of revenue and expenses for the properties (the "Carlyle Properties") referred to in the purchase and sale agreement dated October 1, 2003 between Harvest Operations Corp. and the vender for each of the years in the three year period ended December 31, 2002. This financial information is the responsibility of Harvest Operations Corp. Our responsibility is to express an opinion on this financial information based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial information is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial information. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial information.

In our opinion, this financial information presents fairly, in all material respects, the revenue and expenses for the Carlyle Properties referred to in the purchase and sale agreement dated July 29, 2003 for each of the years in the three-year period ended December 31, 2002.

KPMG LLP

Chartered Accountants

Calgary, Canada
October 3, 2003

CARLYLE PROPERTIES

Schedule of Revenue and Expenses for the Carlyle Properties

	Nine months ended September 30,		Years ended December 31,		
	2003	2002	2002	2001	2000
	(unaudited)		(audited)		
Revenue	$ 59,838,735	$ 60,740,813	$ 85,270,787	$ 89,172,498	$ 119,482,399
Royalties	(12,646,317)	(13,595,661)	(18,163,421)	(19,099,841)	(27,813,069)
	47,192,418	47,145,152	67,107,366	70,072,657	91,669,330
Operating costs	18,057,001	19,334,790	24,688,372	22,610,861	25,202,098
Operating income	$ 29,135,417	$ 27,810,362	$ 42,418,994	$ 47,461,796	$ 66,467,232

See accompanying notes to schedule of revenue and expenses for the Carlyle Properties.

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1. Basis of presentation:

On October 1, 2003 Harvest Operations Corp. entered into a purchase and sale agreement to acquire the properties (the "Carlyle Properties") from an arm's length vender.

The schedule of revenue and expenses for the Carlyle Properties includes the operations of the Carlyle Properties by the previous owners. The schedule of revenue and expenses for the Carlyle Properties includes only amounts applicable to the working interest of the previous owners for the Carlyle Properties.

The schedule of revenue and expenses for the Carlyle Properties does not include any provision for the depletion and depreciation, site restoration, future capital costs, impairment of unevaluated properties, general and administrative costs and income taxes for the Carlyle Properties as these amounts are based on the consolidated operations of the previous owners of which the Carlyle Properties formed only a part.

2. Significant accounting policies:

(a) Revenue:

Revenue from the sale of oil and natural gas is recorded at the time that the product is produced and sold.

(b) Royalties:

Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with Alberta Energy regulations or the terms of individual royalty agreements.

(c) Operating expenses:

Operating expenses include amounts incurred to bring the oil and natural gas to the surface, gather, transport, field process, treat and store same. Operating expenses are reflected net of gathering, processing and transportation revenue associated with the Carlyle Properties.

COMPILATION REPORT

To the Trustee of Harvest Energy Trust and the Directors of Harvest Operations Corp.

We have read the accompanying unaudited pro forma consolidated statement of income of Harvest Energy Trust (the "Trust") for the year ended December 31, 2003, and have performed the following procedures:

1. Compared the figures in the columns captioned "Harvest Energy Trust" to the consolidated financial statements of the Trust for year ended December 31, 2003 and found them to be in agreement.
2. Compared the figures in the columns captioned "Carlyle Properties" to the unaudited schedule of revenue and expenses for the nine-month period ended September 30, 2003.
3. Made enquiries of certain officials of the Trust who have responsibility for financial and accounting matters about:
   (a) The basis for the determination of the pro forma adjustments; and
   (b) Whether the pro forma consolidated statement of income comply in all material respects with the applicable regulatory requirements.

   The officers:

   (a) Described to us the basis for determination of the pro forma adjustments, and
   (b) Stated that the pro forma consolidated statement of income comply as to form in all material respects with the applicable regulatory requirements.
4. Read the notes to the pro forma consolidated financial statements, and found them to be consistent with the basis described to us for determination of the pro forma adjustments.
5. Recalculated the application of the pro forma adjustments to the aggregate of the amounts in the other columns the year ended December 31, 2003 and found the amounts in the column captioned to "Pro forma Consolidated" to be arithmetically correct.

A pro forma financial statement is based on management assumptions and adjustments which are inherently subjective. The foregoing procedures are substantially less than either an audit or a review, the objective of which is the expression of assurance with the adjustments to the historical financial information. Accordingly, we express no such assurance. The foregoing procedures would not necessarily reveal matters of significance to the pro forma financial statements, and we therefore make no representation about the sufficiency of the procedures for the purposes of a reader of such statements.

KPMG LLP

Chartered Accountants

Calgary, Canada
May 10, 2004

HARVEST ENERGY TRUST

Pro Forma Consolidated Statement of Income

Year ended December 31, 2003
(Unaudited)

	Harvest Energy Trust	Carlyle Properties	Adjustments	Notes	Pro Forma Consolidated
Revenue:					
Petroleum and natural gas sale	$ 119,351,486	$ 59,838,736	$ –	2(a)	$ 179,190,222
Hedging loss	(18,924,364)	–	–		(18,924,364)
Royalty income	660,452	–	–		660,452
Royalties	(17,072,534)	(12,646,317)	–	2(a)	(29,718,851)
	84,015,040	47,192,419	–		131,207,459
Expenses:					
Operating	36,044,629	18,057,001	–	2(a)	54,101,630
General and administrative	4,339,738	–	–		4,339,738
Interest and amortization of deferred financing charges	5,582,476	–	1,367,902	2(d)	6,950,378
Site restoration and reclamation	4,354,620	–	1,290,112	2(c)	5,644,732
Depletion, depreciation and amortization	29,361,741	–	4,216,399	2(b)	33,578,140
Foreign exchange gain	(4,373,510)	–	–		(4,373,510)
	75,309,694	18,057,001	6,874,413		100,241,108
Income (loss) before taxes	8,705,346	29,135,418	(6,874,413)		30,966,351
Taxes:					
Large corporation taxes	157,382	–	100,000	2(e)	257,382
Future tax expense	(8,162,038)	–	3,338,245	2(e)	(4,566,411)
	(8,004,656)	–	3,438,245		(4,309,029)
Net income (loss)	$ 16,710,002	$ 29,135,418	$ (10,312,658)		$ 35,275,380
Net income per trust unit:					
Basic	$ 1.33			2(e)	$ 2.09
Diluted	$ 1.29			2(e)	$ 1.80

See accompanying notes to pro forma consolidated financial statements.

1. Basis of presentation:

Harvest Energy Trust (the "Trust") is an open-ended, unincorporated investment trust formed under the laws of Alberta. Pursuant to a trust indenture and an administration agreement, the Trust is managed by its wholly owned subsidiary, Harvest Operations Corp (the "Corporation"). The Trust acquires and holds net profits interests in oil and gas properties acquired and held by the Corporation.

The accompanying unaudited pro forma consolidated statement of income have been prepared by the management of the Corporation in accordance with accounting principles generally accepted in Canada. In the opinion of management, the pro forma consolidated statement of income includes all material adjustments necessary for fair presentation in accordance with generally accepted accounting principles in Canada.

The pro forma financial statement is not necessarily indicative either of the results that actually would have occurred if the events reflected herein had taken place on the dates indicated or of the results that may be obtained in the future.

On October 1, 2003 the Trust and the Corporation entered into an agreement to acquire properties from a third party (the "Carlyle Properties"). The cost to the Corporation was approximately $81.1 million including the closing adjustments and estimated transaction costs of approximately $2 million.

The unaudited pro forma consolidated statement of income for the year ended December 31, 2003 has been based on:

- The audited statement of income and accumulated income of the Trust for the year ended; and
- the unaudited schedule of revenue and expenses for the Carlyle Properties for the six-month period ended June 30, 2003 plus the figures from the applicable accounting information for the three months ended September 30, 2003.

2. Pro forma consolidated statement of income and assumptions and adjustments:

The pro forma consolidated statement of income for the year ended December 31, 2003 have been prepared assuming that the transactions described in note 1 were completed on January 1, 2003 as follows:

(a) Acquisition of Carlyle Properties:

The amounts included in the pro forma consolidated statement of income for the revenue, royalties and operating costs for the Carlyle Properties for the year ended December 31, 2002 have been derived from the schedule of revenue and expenses for the respective periods.

(b) Depletion, depreciation and amortization:

The pro forma adjustments for depletion, depreciation and amortization have been determined using the full cost method of accounting based on combined proved reserves, future development costs and production volumes and incorporation of the costs of acquiring the Carlyle Properties (including estimated future development costs of $10 million).

(c) Provision for future site restoration and reclamation costs:

The pro forma consolidated statements of income include adjustments to the provision for future site restoration and reclamation costs determined on the basis of the rate per unit of production recorded by the Trust and the pro forma production volumes.

(d) Interest and amortization of deferred financing charges:

As the Trust has the ability to settle the interest and principal amounts outstanding under the Equity Bridge Agreement through the issue of trust units, the amounts drawn have been presented in Unitholders' Equity in these pro forma financial statements. The corresponding interest amounts of $1.88 million for the year period ended December 31, 2003 will be presented as a direct charge to accumulated income rather than as a deduction in determining income for the applicable periods.

(e) Taxes:

Large Corporation Tax has been adjusted for each period for the tax that would be applicable to the additional capital resulting from the acquisition of the Carlyle Properties.

For income tax purposes, the Trust is able to, and intends to, claim a deduction for all amounts paid or payable to unitholders, and then to allocate the remaining income, if any, to the unitholders. However, the pro forma adjustment for future income taxes has been based on the assumption that 50% of the incremental cash flow would have been paid by the Corporation to the Trust as a royalty payment.

2. Pro forma consolidated statement of income and assumptions and adjustments (continued):

(f) Income per trust unit:

The number of trust units included in the basic weighted average number outstanding for the period was based on the weighted average number of trust units actually outstanding for the period and the 4,312,500 trust units issued under the terms of the underwriting agreement dated October 7, 2003. The pro forma income available to unitholders was reduced by the interest applicable to amounts drawn under the Equity Bridge Agreement.

The diluted weighted average number of trust units 300,000 trust units with respect to the trust unit incentive plan and 2,509,284 trust units with respect to the settlement of the amounts drawn under the Equity Bridge Agreement.