

This prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons authorized to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. The securities offered hereby have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). See "Plan of Distribution".

PROSPECTUS

Initial Public Offering

November 27, 2002



3,750,000 Trust Units

This prospectus qualifies for distribution 3,750,000 trust units ("Trust Units") to be issued by Harvest Energy Trust (the "Trust") at a price of \$8.00 (the "Offering Price") per Trust Unit (the "Offering"). Each Trust Unit represents an equal undivided beneficial interest in the Trust. Pursuant to the Trust Indenture and the Administration Agreement, the Trust is managed by Harvest Operations Corp. ("Harvest" or the "Corporation"), a wholly-owned subsidiary of the Trust.

The Trust will distribute the Distributable Cash to the holders of Trust Units on a monthly basis. See "Description of the Trust – Cash Available For Distribution" and "Description of the Trust – Distributable Cash".

The actual amount of Cash Available For Distribution and ultimately, the Distributable Cash to be paid to the Unitholders, will depend on, among other things, the quantity of crude oil, natural gas and natural gas liquids produced, prices received for such production, production costs, General and Administrative Costs, Debt Service Charges and net contributions by the Corporation to the Reclamation Fund and the Reserve Fund as well as withholdings of up to 50% of the Cash Available For Distribution in the Capital Fund to finance future acquisitions and development, which will impact Distributable Cash. Management of the Corporation believes this will assist in maintaining distributions for a longer period than would otherwise be the case if all Cash Available For Distribution was immediately distributed to the Unitholders. See "Description of the Trust – Cash Available For Distribution", "Description of the Trust – Distributable Cash" and "Risk Factors".

There is presently no market through which the Trust Units may be sold and purchasers may not be able to resell the securities purchased under this prospectus. The Trust does not represent a traditional investment in the oil and natural gas sector. An investment in the Trust Units is subject to a number of risks that should be considered by a prospective purchaser. See "Risk Factors".

The TSX has conditionally approved the listing of the Trust Units distributed under this prospectus. Listing will be subject to the Trust fulfilling all of the listing requirements of the TSX on or before February 18, 2003, including distribution of the Trust Units to a minimum number of public Unitholders.

The terms of the Offering were established through negotiations between the Corporation, on behalf of the Trust, and FirstEnergy Capital Corp. and Haywood Securities Inc. (collectively, the "Underwriters"). The price per Trust Unit is a function of anticipated Cash Available For Distribution, the value of the Initial Properties and Additional Properties acquired by the Corporation, the value of the Direct Royalties and the Corporation's ability to effect long-term growth in the value of the Trust. See "Risk Factors".

Distributable Cash received by a Unitholder in excess of that Unitholder's share of the Trust's income, computed prior to distributions, will be a return of capital to the Unitholder. The Distributable Cash, which is a return of capital, reduces the adjusted cost base of a Unitholder's investment in the Trust Units. A Unitholder will be subject to tax to the extent that

Distributable Cash represents the Unitholder's share of the Trust's income or to the extent a return of capital to the Unitholder exceeds the Unitholder's adjusted cost base in the Trust Units. See "Canadian Federal Income Tax Considerations".

The Trust is an open-ended unincorporated investment trust established under the laws of the Province of Alberta. The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act (Canada)* and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Price: \$ 8.00 per Trust Unit

	Offering Price ⁽¹⁾	Underwriters' Fee	Net Proceeds to the Trust ⁽²⁾⁽³⁾
Per Trust Unit	\$8.00	\$0.48	\$7.52
Total Offering	\$30,000,000	\$1,800,000	\$28,200,000

Notes:

- (1) The price of the Trust Units has been determined by negotiation between the Corporation, on behalf of the Trust, and the Underwriters.
- (2) Before deducting expenses of the Offering estimated at \$600,000, which, together with the Underwriters' Fee, will be paid by the Trust from the proceeds of the Offering. See "Use of Proceeds".
- (3) The Trust has granted to the Underwriters an option (the "Over-allotment Option"), exercisable for a period of 60 days from the closing of the Offering, to purchase up to an additional 562,500 Trust Units at the Offering Price to cover over-allotments, if any, and for market stabilization purposes. This prospectus qualifies the distribution of the Trust Units issuable upon exercise of the Over-allotment Option. If the Over-allotment Option is exercised in full, the total Offering Price, Underwriters' Fee and Net Proceeds to the Trust (before deducting expenses of the Offering) will be \$34,500,000, \$2,070,000 and \$32,430,000, respectively. See "Plan of Distribution".

The Underwriters, as principals, conditionally offer the Trust Units, subject to prior sale, if, as and when issued, sold and delivered by the Trust and accepted by the Underwriters in accordance with the conditions contained in the Underwriting Agreement referred to under "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Trust and the Corporation by Burnet, Duckworth & Palmer LLP and on behalf of the Underwriters by Blake, Cassels & Graydon LLP. Subscriptions will be received subject to rejection or allotment in whole or in part and the Underwriters reserve the right to close the subscription books at any time without notice. It is expected that the Trust Units will be available for delivery at Closing which is expected to occur on or about December 5, 2002, or such later date as the Trust and the Underwriters may agree, but in any event not later than December 20, 2002.

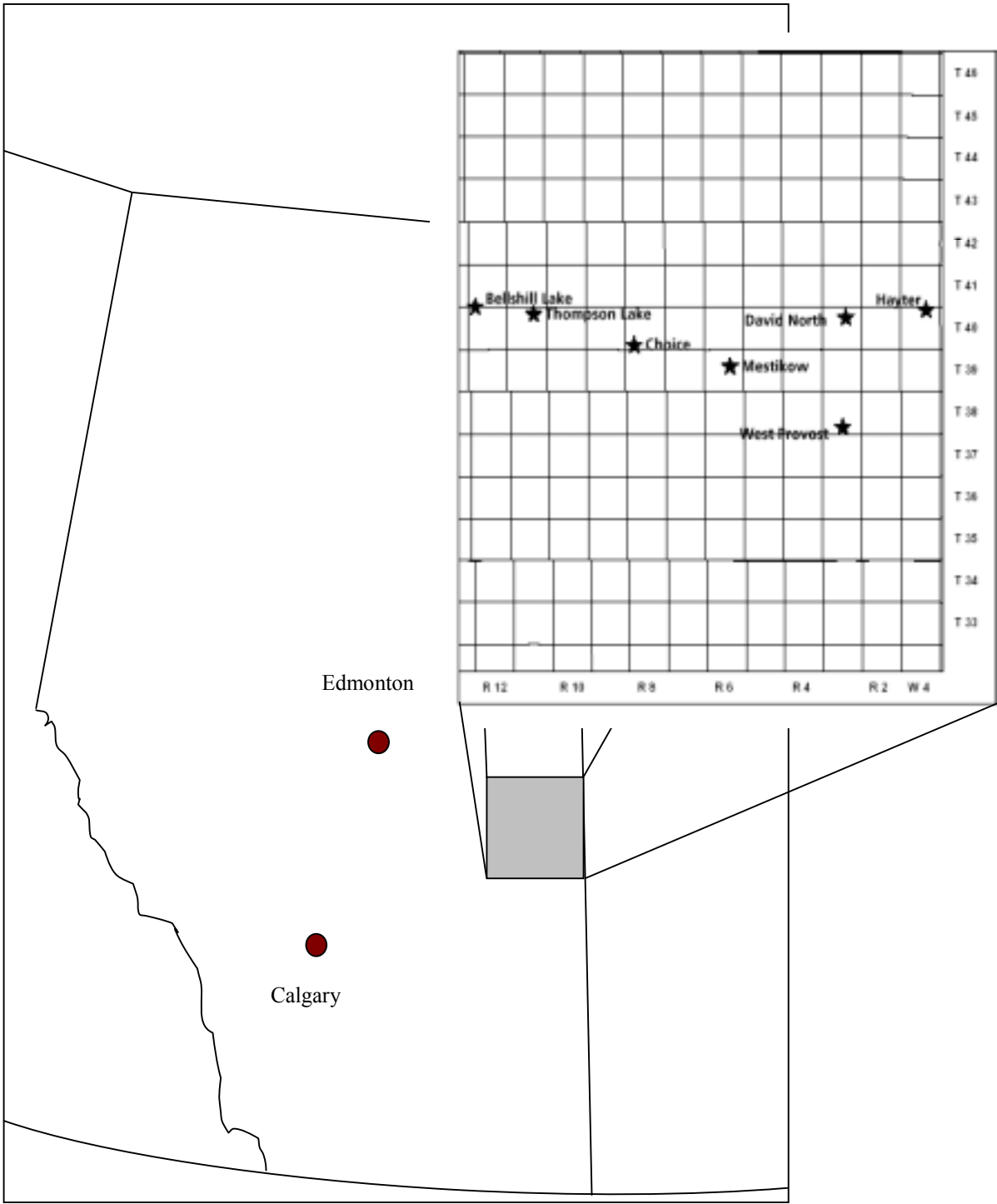


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ELIGIBILITY FOR INVESTMENT

In the opinion of Burnet, Duckworth & Palmer LLP, counsel to the Trust, and Blake, Cassels & Graydon LLP, counsel to the Underwriters, the Trust Units offered hereby, if issued on the date hereof, would be, as at such date, qualified investments under the Tax Act for trusts governed by registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), registered education savings plans ("RESPs") and deferred profit sharing plans ("DPSPs") (collectively, "Plans") provided the Trust qualifies as a mutual fund trust under the Tax Act. In the opinion of such counsel, based in part on a certificate of the Corporation as to factual matters, the Trust Units offered hereby, if issued on the date hereof, would not constitute foreign property for the purposes of the tax imposed under Part XI of the Tax Act on Plans (other than RESPs), registered pension plans, registered investments and certain other entities. RESPs are not subject to the foreign property rules.

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 prospectus. 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 prospectus, and particularly in the risk factors set forth herein under "Risk Factors". Because actual results or outcome 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.

GLOSSARY OF TERMS

In this prospectus, 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.

"**Additional Direct Royalties**" means a 99% undivided interest in the royalty interests acquired by the Corporation in connection with the Additional Properties Acquisition and sold by the Corporation to the Trust pursuant to a Direct Royalties Sale Agreement.

"**Additional Properties**" means the oil and natural gas properties and related assets acquired under the terms of the Additional Properties Agreement. See "Additional Properties".

"**Additional Properties Acquisition**" means the acquisition of the Additional Properties and the Additional Direct Royalties pursuant to the Additional Properties Agreement.

"**Additional Properties Acquisition Cost**" means the aggregate purchase price paid for the Additional Properties and the Additional Direct Royalties, being approximately \$53.2 million, after adjustments. See "Additional Properties" and "Risk Factors".

"**Additional Properties Agreement**" means the agreement of purchase and sale between the Additional Properties Vendor and the Corporation dated August 1, 2002 for the purchase of the Additional Properties and the Additional Direct Royalties.

"**Additional Properties Vendor**" means Anadarko Canada Corporation.

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

"**AEUB**" means the Alberta Energy and Utilities Board.

"**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.

"**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.

"**Canadian resource property**" has the meaning given to that term in the Tax Act.

"**Capital Fund**" means the cumulative amount of cash flow that the Trust will retain from the Cash Available For Distribution to finance future acquisitions and development of the Properties and such retentions may range from 0% to 50% of the annual Cash Available For Distribution, net of cumulative amounts included in Distributable Cash.

"**Caribou**" means Caribou Capital Corp.

"**Cash Available For Distribution**" means, for any particular period, NPI Income and the Direct Royalties, any interest or other income from Permitted Investments, and ARTC received by the Trust net of Non-Deductible Crown royalties that are reimbursed by the Trust to the Corporation plus dividends on the issued and outstanding securities of the Corporation held by

the Trust less direct expenses and liabilities of the Trust including Debt Service Charges, and prior to any retention by the Trust for the Capital Fund. See "Description of the Trust – Cash Available For Distribution".

"Closing" means the closing of this Offering, which is expected to occur on or about December 5, 2002, or such later date as the Trust and the Underwriters may agree, but in any event no later than December 20, 2002.

"Commodity Price and Currency Swaps" means swap, hedging and other arrangements made by the Corporation (including any assumed by the Corporation by contract, operation of law or otherwise), from time to time, in respect of commodity prices or rates of exchange of currencies the purpose of which is to mitigate or eliminate exposure to fluctuations in prices of commodities or rates of exchange of one currency for another which affect Production Costs or revenues attributable to the Properties and includes guarantees, either direct or indirect, by the Corporation of any swap, hedging and other arrangements made by Persons wholly-owned, directly or indirectly, by the Corporation or the Trust provided such Person has guaranteed, directly or indirectly, the Corporation's Commodity Price and Currency Swaps.

"Credit Facilities" means the credit facilities made available to the Corporation or the Trust from time to time, including, without limitation, the Current Bank Facility. See "Information Respecting the Corporation – Borrowing".

"Current Lender" means a syndicate of lenders with WestLB AG, New York Branch as a lender and as administrative agent for all of the lenders. On the date hereof, WestLB AG, New York Branch is the only such syndicate member.

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

"Debt Service Charges" means all interest and principal repayments and other costs, expenses and disbursements relating to the borrowing of funds by the Trust and/or the Corporation, as applicable. See "Information Respecting the Corporation – Borrowing".

"Deferred Purchase Price Obligation" means the ongoing obligation of the Trust to pay to the Corporation, 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, 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 including the Initial Direct Royalties acquired by the Trust from the Corporation pursuant to a Direct Royalties Sale Agreement and the Additional Direct Royalties acquired from the Corporation in connection with the Additional Properties Acquisition.

"Direct Royalties Sale Agreement" means any purchase and sale agreement between the Trust and the Corporation providing for the purchase by the Trust from the Corporation of Direct Royalties including the amended and restated agreement dated September 27, 2002 in respect of the purchase of the Initial Direct Royalties and the agreement dated November 15, 2002 between the Corporation and the Trust in respect of the purchase of the Additional Direct Royalties.

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

"Economic Life" means, with respect to an oil and natural gas property, the time remaining before production of Petroleum Substances from the property is forecast to be uneconomic under escalating cost and price assumptions.

"Established Reserves" means the sum of 50% of the Probable Reserves and 100% of Proved Reserves.

"Facilities" means natural gas processing plants, natural gas compression facilities, natural gas gathering facilities, crude oil batteries, crude oil pipelines, power generation facilities and similar facilities in which Petroleum Substances are compressed, processed, gathered, transported, treated, measured or stored and which are located near the oil or natural gas wells from which such Petroleum Substances are produced.

"Farmout" means an agreement whereby a third party agrees to pay for the drilling of a well on one or more of the Properties in order to earn an interest therein with the Corporation retaining a residual interest in such Properties.

"Future Acquisition Costs" means the acquisition costs relating to any acquisition of Properties after the date of the NPI Agreement.

"General and Administrative Costs" means the aggregate amount representing all expenditures and costs incurred in the management and administration of the Corporation or the Trust reasonably allocable by the Corporation to the Properties including, (a) all reasonable costs and expenses relating to the Corporation and the Trust and paid to third parties by or on behalf of the Corporation or their affiliates; and (b) all reasonable costs and expenses incurred specifically for the Corporation or the Trust relating to the Corporation or the Trust including, auditing, accounting, bookkeeping, rent and other leasehold expenses, legal, land administration, engineering, travel, consulting, telephone, data processing, reporting, executive and management time, salaries, bonuses (including under an executive bonus plan of the Corporation, if any).

"Gross Reserves" means the Corporation's interest, or the interest to be acquired by the Corporation, in reserves before the deduction of royalty interests.

"Initial Direct Royalties" means a 99% undivided interest in the royalty interests acquired by the Corporation in connection with the acquisition of the Initial Properties and sold to the Trust pursuant to a Direct Royalties Sale Agreement.

"Initial Properties" means the properties and assets (other than the Initial Direct Royalties) acquired by the Corporation from the Initial Properties Vendors pursuant to the Sale Agreement. See "Acquisition of NPI" and "Initial Properties".

"Initial Properties Acquisition Cost" means the aggregate purchase price paid for the Initial Properties and the Initial Direct Royalties after adjustments, being \$26.2 million.

"Initial Properties Vendors" means Devon Canada, a partnership, and Devon ARL Corporation.

"Interest Rate Swaps" means interest rate swap, hedging and other arrangements made by the Corporation (including any assumed by the Corporation by contract, operation of law or otherwise), from time to time, the purpose of which is to mitigate or eliminate exposure to fluctuations in interest rates applicable to the Credit Facilities or other interest rates which affect Production Costs and includes guarantees, either direct or indirect, by the Corporation of any interest rate swap, hedging and other arrangements made by Persons wholly-owned, directly or indirectly, by the Corporation or the Trust provided such Person has also guaranteed, directly or indirectly, the Corporation's Interest Rate Swaps.

"Interim Loan" means the loan agreements dated July 10, 2002 and July 30, 2002 between Caribou and the Trust pursuant to which Caribou agreed to advance up to \$43 million to the Trust to finance, in part, the purchase of the NPI, the Initial Direct Royalties and the Additional Direct Royalties from the Corporation. See "Description of the Trust – Interim Loan".

"Management Group" means those directors and officers of the Corporation and their close friends and associates who own the Management Group Debentures. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".

"Management Group Debentures" means debentures of 990148 Alberta Ltd. held by the Management Group. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".

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

"McDaniel Report" means the independent engineering evaluation of the reserves associated with the Initial Properties and the Initial Direct Royalties as at August 1, 2002 conducted by McDaniel on behalf of the Corporation and the Additional Properties and the Additional Direct Royalties as at June 1, 2002 conducted by McDaniel on behalf of Anadarko Canada Corporation (which has been mechanically updated to August 1, 2002), based on constant and escalating price and cost assumptions.

"Miscellaneous Interests" means all miscellaneous properties, assets and rights which are related to Petroleum and Natural Gas Rights or Tangibles (other than Petroleum and Natural Gas Rights and Tangibles).

"Non-Deductible Crown Royalties" means Crown royalties which are either: (i) required to be included in taxable income pursuant to Section 12(1)(o) of the Tax Act or any replacement thereof or substitution therefor; or (ii) not permitted to be

deducted in computing taxable income pursuant to Section 18(1)(m) of the Tax Act or any replacement thereof or substitution therefor.

"Notes" means the promissory notes issued 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 on the following terms and conditions:

- (a) unsecured and bearing interest at 6% per annum payable monthly in arrears on the 20th day of the next following month;
- (b) subordinate to all senior indebtedness which includes all indebtedness for borrowed money or owing in respect of property purchases on any default in payment of any such senior indebtedness, and to all trade debt of the Corporation or any subsidiary of the Corporation or the Trust on any creditor proceedings such as bankruptcy, liquidation or insolvency;
- (c) subject to earlier prepayment, being due and payable on the 15th anniversary of the date of issuance;
- (d) in an aggregate principal amount not exceeding \$500 million, and
- (e) 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 the net profit interest owing by the Corporation to the Trust pursuant to the NPI Agreement.

"NPI Agreement" means the amended and restated net profit interest agreement regarding the creation and sale of the NPI dated September 27, 2002 between the Corporation and the Trustee as trustee for and on behalf of the Trust.

"NPI Deductions" means, the aggregate of (a) the Corporation's share of all costs and expenses in respect of the operation of the Properties and include, without limitation, those relating to (i) the drilling completion, equipping and re-entry of wells (including injection wells); (ii) the compression, dehydration, gathering, treating, processing and transportation of Production or substances produced from the Properties; (iii) the acquisition of Tangibles (including construction of Facilities); (iv) the payment of royalties and similar burdens other than Non-Deductible Crown Royalties; (v) the acquisition of Miscellaneous Interests; (vi) the sale and marketing of Production; (vii) insurance premiums; (viii) property, municipal, mineral and other taxes; (ix) the abandonment of wells and the decommissioning of Tangibles and Facilities; (x) remediation and reclamation of surface sites and clean-up and monitoring of environmental damage; (xi) drilling, transportation and other contracts or contract settlements not assigned to specific Properties; (xii) income, capital and other taxes of the Corporation reasonably allocable by the Corporation to the Properties; (b) Debt Service Charges incurred by the Corporation and any net loss from Interest Rate Swaps; (c) amounts contributed to the Reclamation Fund or the Reserve Fund; (d) General and Administrative Costs in excess of Residual Revenues; and (e) Future Acquisition Costs; but excluding depreciation, deferred taxes and losses from Commodity Price and Currency Swaps.

"NPI Income" in respect of any period for which NPI Income is calculated means: (a) 99% of production revenues from the Properties, less (b) 99% of the amount by which all NPI Deductions for such period exceeds the aggregate, without duplication, for such period of (A) Acquisition Costs paid with the proceeds from the sale of Properties, (B) withdrawals from the Reserve Fund or Reclamation Fund to fund payment of NPI Deductions, (C) advances made pursuant to the Credit Facilities to fund the payment of NPI Deductions, less (ii) those NPI Deductions paid as part of the Deferred Purchase Price Obligation.

"NYMEX" means the New York Mercantile Exchange.

"Offering Documents" means any one or more of a prospectus, information memorandum, private placement memorandum and similar public or private offering documents, including this prospectus, or any understanding, commitment or agreement to issue or offer Trust Units.

"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 will not be 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.

"Petroleum and Natural Gas Rights" means rights to explore for, drill for, produce, save and market Petroleum Substances, including fee simple interests in Petroleum Substances and interests granted pursuant to instruments commonly known as Crown or freehold petroleum and/or natural gas leases, licenses or permits, but not Direct Royalties.

"Petroleum Substances" means petroleum, natural gas and related hydrocarbons, (including condensate and natural gas liquids) and all other substances (including sulphur and its compounds), whether liquid, solid or gaseous and whether hydrocarbons or not, produced in association therewith.

"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 Substances attributed to the Properties.

"Properties" means the working, royalty or other interests of the Corporation from time to time in any petroleum and natural gas rights, tangibles and miscellaneous interests, including the Initial Properties, the Additional Properties and any other properties which may be acquired by the Corporation at a future date (excluding the Direct Royalties).

"Proved Reserves", "Probable Reserves", "Producing Reserves", "Non-Producing Reserves" and "Net Reserves" have the meanings given to those terms under "Initial Properties – Oil and Natural Gas Reserves" and "Additional Properties – Oil and Natural Gas Reserves", as the case may be.

"Reclamation Fund" means the cumulative amount of cash flow that the Corporation will retain from the Properties to fund ongoing environmental obligations net of amounts used to fund NPI Deductions. See "Description of the Trust – Reclamation Fund".

"Record Date" means 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, except that December 31 shall in all cases be a Record Date.

"Reserve Fund" means the cumulative amount of production revenues and Residual Revenues entitled to be retained by the Corporation pursuant to the NPI Agreement to provide for payment of production costs which the Corporation estimates 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 net of amounts used to fund NPI Deductions. See "Description of the Trust – Reserve Fund".

"Reserve Life Index" means the amount obtained by dividing the quantity of reserves by the annualized 2002 production of Petroleum Substances 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 net cash flow from the Established Reserves shown in the most recent engineering report relating to such property, discounted at 10% and using escalating price and cost assumptions (a common benchmark in the oil and natural gas industry).

"Residual Revenues" means: (A) the Corporation's share of any and all net revenues received by Corporation attributable in any way to the Properties other than: (i) revenues used to calculate NPI Income or (ii) the net proceeds of a disposition of the Petroleum and Natural Gas Rights subject to the NPI and include, without limitation, net revenues relating to: transportation, processing, gathering and treatment of third party production, the sale of Tangible and Miscellaneous Interests, insurance proceeds, seismic sale or licensing, incentives and rebates in respect of production costs, net profit or loss relating to Commodity Price and Currency Swaps, take or pay payments, ARTC; and (b) royalty or other similar interests owned by the Corporation other than Direct Royalties less (c) amounts declared as dividends to the shareholders of the Corporation.

"Sale Agreement" means the purchase and sale agreement dated May 28, 2002 and as amended on July 4, 2002 between the Corporation and the Initial Properties Vendors providing for the purchase by the Corporation of the Initial Properties and the Initial Direct Royalties.

"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.

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

- (a) making payments to the Corporation pursuant to the Deferred Purchase Price Obligations under the NPI Agreement;
- (b) acquiring or investing in securities of the Corporation and in the securities of any other entity and borrowing funds or obtaining credit for that purpose; and
- (c) paying costs, fees and expenses associated with the foregoing purposes or incidental thereto,

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.

"TSX" means the Toronto Stock Exchange.

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

"Tangibles" means all tangible property, apparatus, plant, equipment, machinery and facilities used or held for use, from time to time, for purposes of producing Petroleum Substances from the Properties or lands pooled or unitized therewith or for storing, measuring, compressing, treating, processing or collecting such Petroleum Substances, including wellheads, wellhead equipment, tanks, pumps, pump jacks, separators, dehydrators, flow lines and Facilities.

"Third Party" means any Person other than the Corporation, the Trust or an Affiliate of the Corporation.

"Trust" means Harvest Energy Trust.

"Trust Debenture" means the debenture issued August 15, 2002 by the Trust in the principal amount of \$5 million to 990148 Alberta Ltd. (the "Holder") pursuant to which an aggregate of \$5 million was advanced to the Trust to finance, in part, the Trust's obligation pursuant to the Deferred Purchase Price Obligation under the NPI Agreement. The Holder has the option of demanding settlement of the Trust Debenture in Trust Units. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".

"Trust Fund" at any time, shall mean such 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, including the 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 September 27, 2002 between the Trustee and the Corporation as such indenture may be further amended by supplemental indentures from time to time.

"Trust Units" 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.

"Undeveloped Lands" means those lands included in the Initial Properties and the Additional Properties which have not shown definite Proved Reserve or Probable Reserve potential as a result of regional development and/or exploration activities as of the effective date of the McDaniel Report.

"Underwriters" means, collectively, FirstEnergy Capital Corp. and Haywood Securities Inc.

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

"Vendor" means the Initial Properties Vendors or the Additional Properties Vendor, as the case may be.

"Warrants" means 150,000 warrants to purchase 150,000 Trust Units at \$1.00 per Trust Unit issued in connection with the Interim Loan. See "Description of the Trust – Warrants", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".

"working interest" 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.

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	Barrel
Bbls	Barrels
Mbbbls	thousand barrels
Bbls/d	barrels of oil 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.
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.
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.

CONVERSIONS

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

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
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 prospectus are in Canadian dollars, except where otherwise indicated.

PROSPECTUS SUMMARY

The following is a summary of the principal features of the Offering and should be read together with the more detailed information and financial data and statements contained elsewhere in this prospectus. For an explanation of certain terms and abbreviations used in this prospectus, reference is made to the "Glossary of Terms", "Abbreviations" and "Conversions".

The Offering

Issuer:	Harvest Energy Trust
Offering:	3,750,000 Trust Units. Each Trust Unit represents an equal, undivided beneficial interest in the Trust.
Amount:	\$30,000,000
Offering Price:	\$8.00 per Trust Unit
Use of Proceeds:	The net proceeds to the Trust from the Offering are estimated to be \$27.6 million, after deducting the fees payable to the Underwriters and the expenses of the Offering (\$31.83 million, if the Over-allotment Option is fully exercised). The Trust will use approximately \$23.4 million from the net proceeds of the Offering to repay the Interim Loan (including accrued interest) and the balance to partially repay the advance made under the Current Bank Facility which was used to partially fund the Additional Properties Acquisition, as indicated in the table below.

	Assuming Completion of the Offering	Assuming Completion of the Offering with the Exercise of the Over-allotment Option by the Underwriters⁽¹⁾
Repayment of Interim Loan ⁽²⁾	\$23,400,000	\$23,400,000
Partial repayment of Current Bank Facility ⁽³⁾	\$4,200,000	\$8,430,000
Total	\$27,600,000	\$31,830,000

Notes:

- (1) The Trust has granted to the Underwriters the Over-allotment Option, exercisable for a period of 60 days from the Closing, to purchase up to an additional 562,500 Trust Units at the Offering Price to cover over-allotments, if any, and for market stabilization purposes. See "Plan of Distribution".
- (2) Represents repayment of principal and accrued interest. See "Additional Properties", "Description of the Trust – Interim Loan", "Interests of Management and Others in Material Transactions", "Information Respecting the Corporation – Borrowing" and "Use of Proceeds".
- (3) See "Additional Properties", "Interests of Management and Others in Material Transactions", "Information Respecting the Corporation – Borrowing" and "Use of Proceeds".

NPI: The Trust, by virtue of being the owner of the NPI, is entitled to a monthly payment from the Corporation equal to the NPI Income. Pursuant to the NPI Agreement, the NPI will also apply to interests in additional Properties which the Corporation may acquire following the date of Closing. See "Description of the Trust – NPI and Direct Royalties".

In exchange for the NPI, the Trust is required to pay the Deferred Purchase Price Obligation which is to be funded through the further issuance of Trust Units, from the proceeds of sale of Properties or the Capital Fund.

The residual 1% share of gross proceeds from the sale of production which is not part of the NPI and is retained by the Corporation, together with any income of the Corporation 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), will be used to defray certain expenses and capital expenditures of the Corporation.

Direct Royalties:

In addition to the NPI, the Trust will also own Direct Royalties which consist of royalty interests in petroleum and natural gas rights acquired by the Trust from time to time, and include the Initial Direct Royalties and the Additional Direct Royalties. See "Initial Properties" and "Additional Properties".

Cash Distributions:

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.

The Trust intends to retain a portion of the Cash Available For Distribution in the Capital Fund to facilitate future acquisitions and development of the Properties. Management of the Corporation believes this will assist in maintaining distributions for a longer period than would otherwise be the case if all of the Cash Available For Distribution were immediately distributed to the Unitholders. See "Description of the Trust – Cash Available For Distribution", "Description of the Trust – Capital Fund", "Description of the Trust – Distributable Cash" and "Risk Factors".

Concurrent Issue of Trust Units and Dilution:

The Trust will be required to settle its obligations under the Trust Debenture immediately following the Trust qualifying as a mutual fund trust through the listing of the Trust Units on the TSX. The Holder of the Trust Debenture has the option to demand repayment of the Trust Debenture in the form of Trust Units. The number of Trust Units to be issued on settlement of the Trust Debenture is equivalent to the principal and any outstanding interest owing on the Trust Debenture divided by \$1.00. Assuming the payment of interest in cash, the Trust anticipates settling this obligation through the issuance of 5,000,000 Trust Units. It is anticipated that the Management Group Debentures will also then be settled with 5,000,000 Trust Units. The Management Group holds the Management Group Debentures.

In addition, it is anticipated that the Warrants will be exercised for 150,000 Trust Units on completion of the Offering. Caribou, which is controlled by M. Bruce Chernoff, a director of the Corporation, was issued the Warrants pursuant to the Interim Loan. Other than funds advanced under a previous credit facility and the Current Bank Facility, the Management Group and Caribou have provided all of the financing to date for the Trust and the Corporation.

Upon completion of the Offering and subsequent settlement of the Trust Debenture and the Management Group Debentures with Trust Units (assuming the payment of interest in cash) and the exercise of the Warrants, the Management Group and Caribou will have acquired an aggregate of 5,150,000 Trust Units of a total of 8,900,000 Trust Units outstanding (9,462,500 if the Over-allotment Option is exercised in full) at a price of \$1.00 per Trust Unit, which is less than the Offering Price. **The possible issuance of these Trust Units to the Management Group and Caribou will result in dilution to the purchasers of Trust Units pursuant to the Offering.** Members of the Management Group may also subscribe for Trust Units at the Offering Price pursuant to the Offering.

As a condition to completion of the Offering, certain members of the Management Group holding an aggregate \$4,042,500 principal amount of the Management Group Debentures have agreed to execute 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 currently held by such holder or such holder's spouse, directly or indirectly, at any time until the date two years following the date of issue of a final receipt for this prospectus. See "Description of the Trust – Trust Debenture", "Description of the Trust – Interim Loan", "Description of the Trust – Warrants", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".

M. Bruce Chernoff has agreed to purchase, and the Trust has agreed to sell to Mr. Chernoff or his nominee, up to 625,000 Trust Units at the Offering Price, conditional upon closing of the Offering. The remaining directors and officers of the Corporation have also agreed to purchase up to an aggregate of 224,125 Trust Units. See "Interests of Management and Others in Material Transactions".

Eligibility for Investment:

At Closing, the Trust Units will, subject to certain assumptions, be qualified investments for trusts governed by RRSPs, RRIFs and DPSPs. See "Eligibility for Investment".

Background to the Offering

The Corporation was incorporated on May 14, 2002 to carry on oil and natural gas acquisition, development and production activities. As part of this restructuring, the Board of Directors 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 the NPI Agreement. The Corporation's first transaction was the purchase of the Initial Properties and the Initial Direct Royalties from Devon Canada and Devon ARL Corporation on July 10, 2002. See "Acquisition of NPI" and "Initial Properties". The Corporation financed the purchase of the Initial Properties and the Initial Direct Royalties through a previous credit facility which has been repaid in full with funds advanced under the Current Bank Facility and indirectly through the Interim Loan. At the same time, the Corporation sold the Initial Direct Royalties to the Trust pursuant to a Direct Royalties Sale Agreement. See "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan", "Acquisition of NPI" and "Initial Properties – Acquisition of Initial Properties and Initial Direct Royalties".

The Harvest Board continued to evaluate additional properties considered suitable for an investment pursuant to the NPI Agreement. On August 1, 2002, the Corporation entered into the Additional Properties Agreement with Anadarko Canada Corporation to purchase the Additional Properties and the Additional Direct Royalties for a purchase price of \$71.8 million, prior to adjustments. The effective date of the acquisition of the Additional Properties and the Additional Direct Royalties was June 1, 2002, and the acquisition closed on November 15, 2002. The Additional Properties Acquisition Cost of \$53.2 million was funded by an advance under the Current Bank Facility, and indirectly through an additional advance under the Interim Loan. The Trust will use approximately \$23.4 million from the net proceeds of the Offering to repay the Interim Loan (including accrued interest) and approximately \$4.2 million from the net proceeds of the Offering to partially repay the advance made under the Current Bank Facility. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan", "Capitalization of the Trust", "Use of Proceeds" and "Risk Factors".

Selected Pro Forma Information

The following pro forma information reflects combined information related to the Initial Properties and the Additional Properties. See "Initial Properties", "Additional Properties", "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Balance Sheet Harvest Energy Trust As at July 10, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at July 10, 2002 and for the six months ended June 30, 2002 and year ended December 31, 2001" included in this prospectus for a description of each group of properties and their related reserve information, production information and direct revenue and operating expenses.

Selected Pro Forma Reserve Information

The following summary is based upon the McDaniel Report. **The McDaniel Report evaluates the crude oil, natural gas and natural gas liquids reserves attributable to the Initial Properties and the Initial Direct Royalties as at August 1, 2002 and evaluates as of June 1, 2002, with mechanical updates only, to August 1, 2002, crude oil, natural gas and natural gas liquids reserves attributable to the Additional Properties and the Additional Direct Royalties prior to**

provision for income taxes, interest costs (including Debt Service Charges), general and administrative expenses (including General and Administrative Costs), facility site restoration, well abandonment and wellsite restoration costs, but after providing for estimated royalties, operating costs and future capital expenditures. The probable reserves and the present worth value of such reserves as set forth in the table below have been reduced by 50% to reflect the degree of risk associated with recovery of such reserves. It should not be assumed that the discounted future net cash flows estimated by McDaniel represent the fair market value of these reserves. Additional assumptions and qualifications relating to costs, prices for future production and other matters are found under "Selected Pro Forma Information – Pro Forma Reserve Information".

**Pro Forma Petroleum and Natural Gas
Reserves and Pre-Tax Net Cash Flows
Escalating Cost and Price Case**

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows (\$000's) ⁽¹⁾⁽²⁾ Discounted at			
	Gross ⁽¹⁾⁽²⁾	Net ⁽¹⁾⁽²⁾	Gross ⁽¹⁾⁽²⁾	Net ⁽¹⁾⁽²⁾	0%	10%	15%	20%
	Proved Reserves ⁽²⁾							
Producing Reserves ⁽²⁾	9,251	8,225	1,348.3	1,078.8	99,174	83,660	77,911	73,079
Non-Producing Reserves ⁽²⁾	1,903	1,565	298.1	232.9	18,378	14,416	12,882	11,567
Total Proved Reserves ⁽²⁾	11,154	9,790	1,646.4	1,311.7	117,552	98,076	90,793	84,646
Risked Probable Reserves ⁽²⁾	1,272	1,113	169.9	133.1	15,200	10,439	8,927	7,763
Established Reserves ⁽²⁾	12,426	10,903	1,816.2	1,444.8	132,752	108,515	99,720	92,409

Notes:

- (1) Columns may not add due to rounding.
- (2) See Notes (2) through (11) to "Initial Properties – Oil and Natural Gas Reserves" and Note 3 to "Additional Properties – Oil and Natural Gas Reserves".

**Pro Forma Petroleum and Natural Gas
Reserves and Pre-Tax Net Cash Flows
Constant Cost and Price Case**

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows (\$000's) ⁽¹⁾⁽²⁾ Discounted at			
	Gross ⁽¹⁾⁽²⁾	Net ⁽¹⁾⁽²⁾	Gross ⁽¹⁾⁽²⁾	Net ⁽¹⁾⁽²⁾	0%	10%	15%	20%
	Proved Reserves ⁽²⁾							
Producing Reserves ⁽²⁾	9,254	8,218	1,349.0	1,079.4	127,416	104,243	95,835	88,860
Non-Producing Reserves ⁽²⁾	1,903	1,564	298.1	232.9	22,139	17,376	15,544	13,978
Total Proved Reserves ⁽²⁾	11,157	9,782	1,647.1	1,312.3	149,555	121,619	111,379	102,838
Risked Probable Reserves ⁽²⁾	1,272	1,112	169.9	133.1	19,508	13,092	11,075	9,534
Established Reserves ⁽²⁾	12,429	10,893	1,817.0	1,445.4	169,063	134,711	122,454	112,372

Notes:

- (1) Columns may not add due to rounding.
- (2) See Notes (2) through (11) to "Initial Properties – Oil and Natural Gas Reserves" and Note 3 to "Additional Properties – Oil and Natural Gas Reserves".

Pro Forma Incremental Exploitation and Development Potential

Management of the Corporation has identified several opportunities to take advantage of possible development potential and increase existing production in the Initial Properties and Additional Properties which are supplemental to the future development projects included in the determination of the Reserve Values contained in the McDaniel Report. A summary of the opportunities being considered are noted below. See "Initial Properties – Incremental Exploitation and Development Potential" and "Additional Properties – Incremental Exploitation and Development Potential" for a more detailed discussion of these opportunities.

- **Hayter:** Drilling additional in-fill wells using shorter horizontal wells (200-300 metres in length), spaced at 20-25 metres to access reserves currently not being effectively depleted through existing wells.

- **West Provost:** Potential opportunity to selectively drill horizontal wells within structurally high areas in the pool.
- **Thompson Lake:** Drilling 10 additional development locations.
- **David North:** Undertaking 20 well re-completions to convert wells which have been producing in the Lloydminster and/or Dina zones to oil producers from the Cummings and Sparky formations.
- **Bellshill Lake:** Drilling additional horizontal wells which have been identified through a review of 3-D seismic data.

Neither the capital costs nor the potential incremental production associated with these opportunities are reflected in the McDaniel Report.

The Corporation may also identify further development projects and other opportunities to optimize production from the Initial Properties and the Additional Properties and implement operational efficiencies to lower operating expenses from those forecasted in the McDaniel Report as it enhances its understanding of the operations of the Initial Properties and the Additional Properties.

Selected Pro Forma Production Information

The sales volumes of crude oil, natural gas, and natural gas liquids attributable to the Initial Properties and the Additional Properties, before deduction of royalties, for the periods indicated are summarized below. Average production for the month of September, 2002 was approximately 9,380 BOE/d.

	6 Month Period Ended June 30, 2002⁽¹⁾ (unaudited)	Year Ended December 31,⁽¹⁾		
		2001 (unaudited)	2000 (unaudited)	1999 (unaudited)
Crude oil and natural gas liquids (Mbbbls)	1,768	3,938	3,642	3,326
Average daily production (Bbbls/d)	9,771	10,789	9,980	9,112
Natural gas sales (Mmcf)	203	481	345	381
Average daily sales (Mcf/d)	1,118	1,315	946	1,042
Total oil equivalent (MBOE)	1,802	4,018	3,700	3,389
Average daily production (BOE/d)	9,957	11,008	10,138	9,284

Notes:

- (1) Based on information provided to the Corporation by the Initial Properties Vendors in respect of the Initial Properties and the Additional Properties Vendor in respect of the Additional Properties.
- (2) See Notes to "Initial Properties – Production History" and "Additional Properties – Production History".

Pro Forma Direct Revenue and Operating Expenses

The following table sets forth revenue and operating expenses directly attributable to the Initial Properties and the Additional Properties for the periods indicated.

	6 Month Period Ended June 30, 2002⁽¹⁾ (unaudited)	Year Ended December 31,⁽¹⁾⁽²⁾		
		2001 (unaudited)	2000 (unaudited)	1999 (unaudited)
Revenue:				
Petroleum and natural gas sales ⁽¹⁾	47,162	88,290	118,422	73,199
Royalties	7,685	14,132	18,872	10,253
Operating expenses	11,888	24,419	18,133	14,719
Operating Income	27,589	49,739	81,417	48,227

Notes:

- (1) See "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Balance Sheet Harvest Energy Trust As at July 10, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at July 10, 2002 and for the six months ended June 30, 2002 and year ended December 31, 2001" included in this prospectus.
- (2) See Notes to "Initial Properties – Direct Revenue and Operating Expenses" and "Additional Properties – Direct Revenue and Operating Expenses".

Description of the Trust

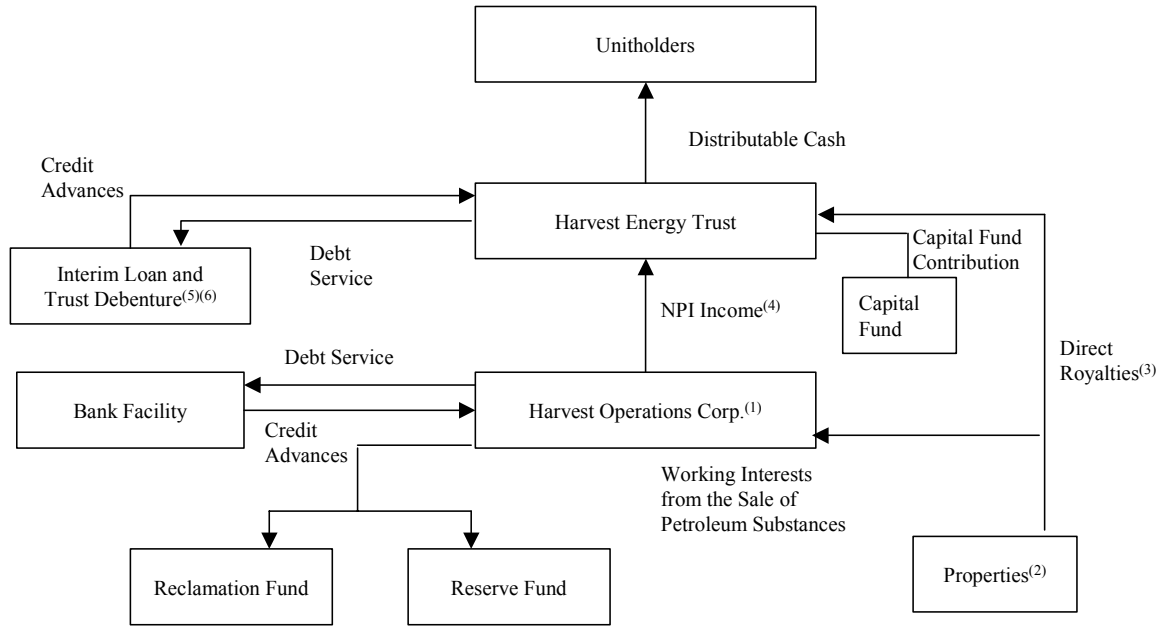
The Trust is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta. The Trust is not managed by a third party manager. Instead, the Trust is managed by the Corporation, its wholly-owned subsidiary, pursuant to the Trust Indenture and the Administration Agreement.

The Trust was established for the purposes of:

- (a) acquiring the NPI and Direct Royalties (including the Initial Direct Royalties and the Additional Direct Royalties);
- (b) making payments to the Corporation pursuant to the Deferred Purchase Price Obligation under the NPI Agreement;
- (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.

It is currently anticipated that the only income to be received by the Trust will be from the NPI and the Direct Royalties. See "Description of the Trust – Cash Available For Distribution" and "Description of the Trust – Distributable Cash".

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



Notes:

- (1) A wholly-owned subsidiary of the Trust. See "Information Respecting the Corporation".
- (2) The Corporation owns the Initial Properties and the Additional Properties and may acquire or dispose of other Properties from time to time. See "Acquisition of NPI", "Initial Properties" and "Additional Properties".
- (3) In addition to the NPI, the Trust holds the Initial Direct Royalties and the Additional Direct Royalties. See "Description of the Trust – NPI and Direct Royalties", "Acquisition of NPI", "Initial Properties" and "Additional Properties". Direct Royalties are also anticipated to include other royalty interests acquired by the Trust from time to time.
- (4) Pursuant to the NPI Agreement, the Corporation will make regular monthly payments to the Trust in the amount of NPI Income. See "Description of the Trust – NPI and Direct Royalties".
- (5) The Trust intends to use approximately \$23.4 million from the net proceeds of the Offering to repay the Interim Loan (including accrued interest) and approximately \$4.2 million from the net proceeds of the Offering to partially repay the advance made under the Current Bank Facility which was used to partially fund the Additional Properties Acquisition. See "Description of the Trust – Interim Loan", "Information Respecting the Corporation – Borrowing", "Capitalization of the Trust", "Use of Proceeds" and "Interests of Management and Others in Material Transactions".
- (6) An aggregate of 5,000,000 Trust Units may be issuable upon settlement of the Trust Debenture. See "Description of the Trust – Trust Debenture", "Description of the Trust – Warrants", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".
- (7) The Trust intends to retain up to 50% of the Cash Available For Distribution in its Capital Fund to finance future acquisitions and development of the Properties.

An unlimited number of Trust Units may be issued pursuant to the Trust Indenture. The Trust Units represent equal undivided beneficial interests in the Trust. All Trust Units will share equally in all distributions from the Trust and all Trust Units will carry equal voting rights at meetings of Unitholders. No Unitholder will be liable to pay any further calls or assessments in respect of the Trust Units. No conversion, retraction, redemption or pre-emptive rights attach to the Trust Units, other than the redemption rights described under "The Trust Indenture – Redemption Right".

The Corporation

The Corporation was incorporated on May 14, 2002 to carry on oil and natural gas acquisition, development and production activities. As part of this restructuring, the Board of Directors 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 the NPI Agreement. See "Background to the Offering".

The Corporation currently has a board of directors consisting of 4 individuals. Pursuant to the Trust Indenture, future directors will be elected by the Trustee in accordance with the Ordinary Resolutions adopted at the annual meeting of the Unitholders. Unitholders are entitled to cause the election of all of the directors. See "Description of the Trust – Board of Directors" and "Information Respecting the Corporation".

Pursuant to the Trust Indenture and the Administration Agreement, the Corporation manages and administers 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, and the Corporation has a staff of 12 people 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 substances.

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

- maximizing 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 existing Properties and acquiring additional Properties.

These objectives are considered by the management of the Corporation as fundamental to the successful operation of the Trust and will be pursued on a balanced basis to enhance benefits to the Unitholders.

Senior Management

The following is a brief description of the backgrounds of the President, Vice President, Finance and Vice President, Operations of the Corporation:

Jacob Roorda, President

- Mr Roorda has been employed in various business and technical roles in the Canadian oil and natural gas industry for 23 years. The majority of his recent experience has been focused on managing and growing, through successful property acquisitions, oil and natural gas producing organizations.
- From 1991 to 1996, Mr. Roorda was Manager, Business Development at Fletcher Challenge Petroleum Inc. ("Fletcher"). In January 1996, Mr. Roorda co-founded PrimeWest Energy Trust ("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 Corporation ("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.

David Fisher, Vice-President, Finance

- Mr. Fisher has over 20 years of experience in various financial roles related to the oil and natural gas industry.
- From 1980 to 1995, Mr. Fisher worked as an external auditor at 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 also as an independent consultant providing financial administration for domestic and international entities.
- From 1995 to July 1998, Mr. Fisher was the Vice President, Finance and Chief Financial Officer of Canrise Resources Ltd. ("Canrise"), a public upstream oil and natural gas corporation.
- From September 1998 to October, 2002, Mr. Fisher was a founder, Director and Vice President, Finance and Chief Financial Officer of Integra Resources Ltd. ("Integra"), a private upstream oil and natural gas corporation. 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.

J.A. Ralston, Vice-President, Operations

- Mr. Ralston has over 20 years of oil and natural gas operations experience. Throughout his career, Mr. Ralston has focused on hands-on property management and value extraction from oil and natural gas production.
- 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 Petroleum ("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. Penn West's production included approximately 9,000 Bbls/d of 16° heavy oil in Saskatchewan and Alberta.

The past performance of each of the individuals indicated above is not necessarily indicative of future performance.

Tax Considerations

In the opinion of Burnet, Duckworth & Palmer LLP, counsel to the Trust, and Blake, Cassels & Graydon LLP, counsel to the Underwriters, the Trust and the distributions from the Trust to Unitholders will be treated, for Canadian federal income tax purposes, as described under "Canadian Federal Income Tax Considerations".

Each Unitholder is required to include in computing income for a particular taxation year the Unitholder's pro-rata share of the Trust's income for tax purposes that was paid or payable in that year by the Trust to the Unitholder together with all amounts designated to the Unitholder as reimbursed Crown charges in excess of the resource allowance deducted in computing the Trust's income for tax purposes. All other amounts received by Unitholders will be deducted from the adjusted cost base of Trust Units.

To the extent the Trust makes a distribution to Unitholders in excess of the Trust's income for tax purposes for the taxation year in respect of which a distribution is made, the excess will be treated as having been made out of the capital of the Trust and will not be included in a Unitholder's income for purposes of the Tax Act. Instead, a Unitholder's pro rata share of such excess distributions will be considered to be a return of capital and will reduce the adjusted cost base of the Unitholder's Trust Units. Where the aggregate amount of capital distributions by the Trust received by a Unitholder exceeds the adjusted cost base of a Unitholder's Trust Units, the Unitholder will be deemed to have recognized a gain from the disposition of Trust Units in the taxation year in which the excess arises.

A Unitholder who disposes of Trust Units held as capital property will have a capital gain (or loss) to the extent that the proceeds of disposition of the Trust Units exceed (or are exceeded by) the adjusted cost base of the Trust Units and disposition expenses.

Prospective purchasers should consult their tax advisors regarding the tax implications of an investment in Trust Units. See "Canadian Federal Income Tax Considerations".

Risk Factors

An investment in the Trust Units will be subject to a number of risks, including: (i) the volatility of oil, natural gas and natural gas product prices; (ii) the Trust's and the Corporation's ability to replace reserves by purchasing reserves or otherwise; (iii) depletion and recoverability of reserves and reserves estimates; (iv) environmental concerns; (v) debt service; (vi) changes in legislation; (vii) the nature of oil and natural gas operations; (viii) reliance on the Corporation; (ix) potential conflicts of interest; (x) investment eligibility; (xi) the nature of the Trust Unit form of security; and (xii) fluctuations in interest rates.

The actual amount of Cash Available For Distribution and ultimately, the Distributable Cash paid to Unitholders, will depend on, among other things, the quantity of crude oil, natural gas and natural gas liquids produced, prices received for such production, production costs, General and Administrative Costs, Debt Service Charges and net contributions by the Corporation to the Reclamation Fund and the Reserve Fund. The Trust intends to retain up to 50% of the Cash Available For Distribution in the Capital Fund to finance acquisitions and development of the Properties, which will impact Distributable Cash. Management of the Corporation believes this will assist in maintaining distributions for a longer period than would otherwise be the case if all Cash Available For Distribution were immediately distributed to the Unitholders. See "Description of the Trust – Cash Available For Distribution", "Description of the Trust – Distributable Cash" and "Risk Factors".

The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional \$5.7 million adjustment to the Additional Properties Acquisition Cost should be made in favour of the Additional Properties Vendor. This dispute relates to whether or not the value of a hedging contract held by the Additional Properties Vendor impacts the net proceeds from the Additional Properties from the effective date of the Additional Properties Acquisition of June 1, 2002 to the closing date of November 15, 2002. The Additional Properties Vendor has indicated its intent to charge the Corporation the additional \$5.7 million as an interim adjustment within 90 days of the closing of the Additional Properties Acquisition. Management of the Corporation believes that such amount is not owing to the Additional Property Vendor. This dispute is expected to be resolved through an arbitration process established in the Additional Properties Agreement. See "Additional Properties" and "Risk Factors".

The Trust Indenture provides that Unitholders will not be liable for or in respect of the obligations of the Trust and that any contracts entered into on behalf of the Trust will not be personally binding on the Trustee, the Corporation or any Unitholder and any liability will be limited to and satisfied only out of the assets of the Trust. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of the Trust to the same extent that a shareholder is protected from the liabilities of a corporation. See "The Trust Indenture – Unitholder Limited Liability" and "Risk Factors – Unitholder Limited Liability".

The Reserve Value of the Initial Properties and the Additional Properties as estimated in the McDaniel Report is based in part on cash flows to be generated in future years as a result of the development projects intended to be undertaken in future years and related capital expenditures. The Reserve Value of the Initial Properties and the Additional Properties as estimated in the McDaniel Report will be reduced to the extent that those development projects do not achieve the level of success assumed in the McDaniel Report.

The Trust does not represent a traditional investment in the oil and natural gas sector. There is presently no market through which the Trust Units may be sold and purchasers may not be able to resell the securities purchased under this prospectus. Prospective purchasers of the Trust Units should carefully consider the information set forth under "Risk Factors" and the other information set forth herein before deciding to invest in the Trust Units.

BACKGROUND TO THE OFFERING

The Corporation was incorporated on May 14, 2002 to carry on oil and natural gas acquisition, development and production activities. As part of this restructuring, the Board of Directors 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 the NPI Agreement. The Corporation's first transaction was the purchase of the Initial Properties and the Initial Direct Royalties from Devon Canada and Devon ARL Corporation on July 10, 2002. See "Acquisition of NPI" and "Initial Properties". The Corporation financed the purchase of the Initial Properties and the Initial Direct Royalties through a previous credit facility which has been repaid in full with funds advanced under the Current Bank Facility and indirectly through the Interim Loan. At the same time, the Corporation sold the Initial Direct Royalties to the Trust pursuant to a Direct Royalties Sale Agreement. See "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan", "Acquisition of NPI" and "Initial Properties – Acquisition of Initial Properties and Initial Direct Royalties".

The Harvest Board continued to evaluate additional properties considered suitable for an investment pursuant to the NPI Agreement. On August 1, 2002, the Corporation entered into the Additional Properties Agreement with Anadarko Canada Corporation to purchase the Additional Properties and the Additional Direct Royalties for a purchase price of \$71.8 million, prior to adjustments. The effective date of the acquisition of the Additional Properties and the Additional Direct Royalties was June 1, 2002, and the acquisition closed on November 15, 2002. The Additional Properties Acquisition Cost of \$53.2 million was funded by an advance under the Current Bank Facility, and indirectly through an additional advance under the Interim Loan. The Trust will use approximately \$23.4 million from the net proceeds of the Offering to repay the Interim Loan (including accrued interest) and approximately \$4.2 million from the net proceeds of the Offering to partially repay the advance made under the Current Bank Facility which was used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan", "Capitalization of the Trust" and "Use of Proceeds".

ACQUISITION OF NPI

Pursuant to the NPI Agreement, the Trust acquired the NPI from the Corporation. The purchase price of the NPI was \$12.6 million which was financed with the proceeds from the Interim Loan. See "Information Respecting the Corporation – Capitalization" and "Description of the Trust – NPI and Direct Royalties" for more details regarding the financing of the purchase of the NPI and a description of the NPI. See also "Initial Properties" and "Additional Properties" for a description of the Properties subject to the NPI and the Initial Direct Royalties and Additional Direct Royalties acquired by the Trust in addition to the NPI.

INITIAL PROPERTIES

Acquisition of Initial Properties and Initial Direct Royalties

The acquisition of the Initial Properties and the Initial Direct Royalties by the Corporation was made pursuant to the Sale Agreement between the Corporation and the Initial Properties Vendors which closed on July 10, 2002. Pursuant to the Sale Agreement, the Corporation purchased the Initial Properties and the Initial Direct Royalties from the Initial Properties Vendors for the Initial Properties Acquisition Cost of \$26.2 million. The purchase price of the Initial Properties and the Initial Direct Royalties was determined by negotiations between the Corporation and the Initial Properties Vendors and was financed with proceeds from a previous credit facility which has been repaid in full with advances made under the Current Bank Facility and indirectly from the Interim Loan. See "Description of the Trust – Interim Loan", "Information Respecting the Corporation – Borrowing" and "Capitalization of the Trust". The Initial Direct Royalties were then sold to the Trust from the Corporation for \$500,000 pursuant to a Direct Royalties Sale Agreement.

Description of Initial Direct Royalties

The Initial Direct Royalties include an overriding royalty interest of 7.10688% in the Choice Viking Gas Unit No. 1, which is operated by Apache Canada Ltd. The Unit consists of rights for natural gas in the Viking formation and is located at Township 40, Ranges 9 and 10 in Alberta, with the unit currently producing from seven of nine wells at a gross rate of 525 (net 37) Mcf/d.

Description of Initial Properties

The Initial Properties include both unitized and non-unitized oil and natural gas production as well as 6,675 net acres of Undeveloped Land. The Corporation operates all of the Initial Properties and the Corporation's average working interest is approximately 99%. Operatorship enables the Corporation to exercise management and operating control to potentially enhance the value of the Initial Properties for the benefit of the Trust. See "Description of the Trust – Decision Making", "Description of the Trust – Management of the Trust" and "Information Respecting the Corporation – Management Policies and Strategies".

The McDaniel Report assigned 4,573 MBOE of Established Reserves to the Initial Properties, before deduction of royalties.

The Initial Properties are concentrated in a relatively small area from Townships 39 to 43 and Ranges 3 to 12 W4M in east central Alberta. The Initial Properties include interests in the following major oilfields: Thompson Lake, David North, Bellshill Lake and Metiskow, all of which are described in more detail below. **Unless otherwise indicated, all information set forth below is net to the Corporation.**

Thompson Lake

The Corporation has approximately a 99% working interest and operates this area that is currently producing approximately 1,420 BOE/d of primarily 27° API oil, at a 99% water cut, from the Provost Glauconite "A" Pool located in Twp. 40 and 41 – 11 W4M. The McDaniel Report has assigned 2,449 MBOE of Established Reserves, before deduction of royalties, to this area. The Thompson Lake field contains 192 gross producing wells.

The wells in this area produce from a thick lower Cretaceous channel sand that is underlain by an active aquifer. The majority of the wells in this area are equipped with progressive cavity pumps to maximize fluid production. The Thompson Lake fluid production in the area is gathered at a central battery located at 4-2-41-11 W4M in which the Corporation 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 Bellshill pipeline to the Hardisty terminal. Solution natural gas is conserved and processed at the EnCana 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, by reducing the power requirements associated with water handling. The Initial Properties Vendors implemented the use of decentralized inclined free-water knockouts. These inclined units optimize emulsion treating and water injection systems by removing free-water from the production stream closer to the producing wells. These inclined units operate essentially at wellhead pressure eliminating the need for injection pumps, as the injection wells are able to take water on vacuum. Six inclined units have been installed to date, matched with one injection well per unit. AEUB approval has been obtained to utilize two injection wells at each inclined unit. Expanded use of the inclined free-water knockouts in the area could result in increased efficiency and lower operating costs (as a result of the lower power costs with the reduced use of injection pumps). Production optimization through total fluid increases at the wells could have a significant impact on production rates and recoveries.

Operating costs for this area since 2001 have been slightly higher than historical averages due to the number of water injection optimization projects carried out in the year and a facility disruption that reduced production for an extended period. The combined effect of these events has resulted in higher per-unit costs. The Corporation anticipates that the results of these water injection optimization projects have not yet been fully reflected in the historical results.

David North

The Corporation has a 100% working interest in this operated property that is currently producing approximately 785 BOE/d of primarily 25° 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 McDaniel Report has assigned 1,036 MBOE of Established Reserves, before deduction of royalties, to this area. The David North field contains 54 gross producing wells.

The David North fluid production in the area is gathered to the central battery located at 15-26-40-3 W4M in which the Corporation has 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 North Hansman Gas Plant 8-14-39-3 W4M.

The Initial Properties Vendors implemented the use of inclined free-water knockouts in the area to optimize emulsion treating and water handling. The inclined units operate essentially at wellhead pressure and may eliminate the need for injection pumps, as the disposal wells are able to take water on vacuum. The inclined units enable significant decreases in operating costs as a result of the lower power costs with the reduced use of injection pumps. Expanded use of the inclined free-water knockouts could result in increased efficiency, lower operating costs and increased fluid handling capacity.

Further development potential exists in this area through additional drilling. The Corporation is 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. Up to 20 additional wells have been identified for re-completion.

Bellshill Lake

The Corporation has a 100% working interest in 1,120 acres of land in Sections 5 and 6-41-12 W4M which is adjacent to the Bellshill Blairmore Unit. This operated property is currently producing approximately 450 BOE/d of primarily 23° API oil, at a 98% water cut, from the Ellerslie "A" Pool and natural gas from the Glauconite "A" Pool. The McDaniel Report has assigned 833 MBOE of Established Reserves, before deduction of royalties, to this area. The Bellshill Lake field contains 18 gross producing wells.

Production from this area has been developed exclusively with horizontal wells. The wells produce from a thick lower Cretaceous channel sand that is underlain by an active aquifer. The majority of the wells in this area are equipped with progressive cavity pumps to maximize fluid production. The Bellshill Lake fluid production in the area is gathered at a central battery located at 11-5-41-12 W4M in which the Corporation has 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-operated 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, already identified by 3-D seismic. There is currently an estimated 180 Bbls/d of oil shut-in due to limited water injection capacity. The drilling of vertical water injection wells would also allow for production increases. The addition of inclined free-water knockouts could also increase water disposal efficiency and capacity.

Metiskow

The Corporation has a 100% working interest in this operated property, which is currently producing approximately 135 Bbls/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 McDaniel Report has assigned 183 MBOE of Established Reserves, before deduction of royalties, to this area. The pool contains 5 gross producing wells.

The Metiskow fluid production in the area is gathered at a central battery located at 5-22-39-6 W4M in which the Corporation has a 100% working interest. The battery has a capacity of approximately 13,500 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Bellshill pipeline to the Hardisty terminal.

Additional potential exists for a new pool in Section 7-39-6 W4M, based on geological and geophysical mapping. The Corporation also has 3-D seismic covering a portion of the property, which may identify additional horizontal drilling locations in the Dina "E" Pool.

Undeveloped Lands

Approximately 7,892 (6,675 net) acres of Undeveloped Lands, all of which are located in the Thomson Lake area, were acquired by the Corporation from the Initial Properties Vendors as part of the Initial Properties. The Corporation has assigned a value of \$333,750 to these Undeveloped Lands. The Corporation intends to conduct a review of available seismic and other data and develop an exploitation plan regarding these Undeveloped Lands. Capital expenditures, Farmouts or dispositions may result in future cash flow from these Undeveloped Lands.

Marketing Arrangements

All of the oil production from the Initial Properties is sold via evergreen contracts with 30 day cancellation notice provisions. David North and Thompson Lake natural gas is sold on a spot basis. Natural gas production at Metiskow is flared.

Oil and Natural Gas Reserves

McDaniel has prepared the McDaniel Report dated August 21, 2002, evaluating as at August 1, 2002 the crude oil, natural gas and natural gas liquids reserves attributable to the Initial Properties and the Initial Direct Royalties. **The McDaniel Report evaluates the crude oil, natural gas and natural gas liquids reserves attributable to the Initial Properties prior to provision for income taxes, interest costs (including Debt Service Charges), general and administrative expenses (including General and Administrative Costs), facility site restoration, well abandonment and well site restoration costs, but after providing for estimated royalties, operating costs and future capital expenditures. The probable reserves and the present worth value of such reserves as set forth in the tables below have been reduced by 50% to reflect the degree of risk associated with recovery of such reserves. It should not be assumed that the discounted future net production revenues estimated by McDaniel represent the fair market value of the reserves.** Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes following the tables.

Initial Properties Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows Escalating Cost and Price Case

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas ⁽⁶⁾ (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows (\$000's) ⁽¹⁾⁽²⁾⁽⁷⁾⁽⁸⁾⁽¹¹⁾ Discounted at			
	Gross ⁽⁴⁾	Net ⁽³⁾	Gross ⁽⁴⁾	Net ⁽³⁾	0%	10%	15%	20%
	Proved Reserves ⁽⁴⁾							
Producing Reserves ⁽⁴⁾	3,897	3,669	1,028.3	823.6	47,252	38,939	35,909	33,388
Non-Producing Reserves ⁽⁴⁾	36	33	298.1	232.9	1,205	935	833	748
Total Proved Reserves ⁽⁴⁾	3,933	3,702	1,326.4	1,056.5	48,457	39,873	36,742	34,136
Riskied Probable Reserves ⁽⁵⁾	393	372	160.3	125.5	5,716	3,642	3,012	2,540
Established Reserves ⁽⁴⁾	4,326	4,073	1,486.7	1,183	54,173	43,515	39,754	36,676

Initial Properties Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows Constant Cost and Price Case

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas ⁽⁶⁾ (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows (\$000's) ⁽¹⁾⁽²⁾⁽⁷⁾⁽⁸⁾⁽¹⁰⁾ Discounted at			
	Gross ⁽⁴⁾	Net ⁽³⁾	Gross ⁽⁴⁾	Net ⁽³⁾	0%	10%	15%	20%
	Proved Reserves ⁽⁴⁾							
Producing Reserves ⁽⁴⁾	3,900	3,667	1,029.0	824.2	61,821	49,311	44,850	41,188
Non-Producing Reserves ⁽⁴⁾	36	33	298.1	232.9	1,360	1,046	929	831
Total Proved Reserves ⁽⁴⁾	3,936	3,699	1,327.1	1,057.1	63,181	50,357	45,779	42,019
Riskied Probable Reserves ⁽⁵⁾	393	371	160.3	125.5	7,330	4,559	3,726	3,107
Established Reserves ⁽⁴⁾	4,329	4,070	1,487.4	1,183.5	70,511	54,916	49,505	45,126

Notes:

- (1) Columns may not add due to rounding.
- (2) Does not include the value of the Undeveloped Lands.
- (3) Represents the Corporation's interest (and includes the Initial Direct Royalties of the Trust) after deduction of royalty encumbrances payable to others (excluding the Trust).
- (4) The following definitions have been used in the McDaniel Report:
 - (a) "Gross Reserves" represents the Corporation's interest (and includes the Initial Direct Royalties of the Trust) before deduction of royalty encumbrances payable to others (excluding the Trust).
 - (b) "Proved Reserves" means those reserves estimated as recoverable under current technology and existing economic conditions from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.
 - (c) "Probable Reserves" means those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be Proved under current technology and existing or anticipated economic conditions but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

- (d) "Established Reserves" means the sum of 50% of Probable Reserves and 100% of Proved Reserves.
- (e) "Producing Reserves" means those reserves that are actually on production, or if not producing, that could be recovered from existing wells or facilities and where the reasons for the current non-producing status is the choice of the owner
- (f) "Non-Producing Reserves" means those proved reserves that are not currently producing either due to lack of facilities and/or markets.
- (5) **The present worth values and quantities of Probable Reserves have been risked by reducing those values by 50% to reflect the degree of risk associated with the recovery of those reserves.**
- (6) All natural gas reserves are reserves remaining after deducting surface losses due to processing shrinkage and raw natural gas used as lease fuel.
- (7) The U.S./\$Cdn. exchange rate used in the McDaniel Report was \$0.65 in 2002 and 2003; \$0.66 in 2004; \$0.67 in 2005 and \$0.68 thereafter.
- (8) The McDaniel Report estimates total capital expenditures (net to the Corporation) to achieve the estimated future pre-tax net cash flows from the Established Reserves, Proved Reserves and Probable Reserves based on escalating cost and price assumptions to be \$240,000 (\$208,000 if discounted by 15% per annum) with \$Nil, \$230,000 and \$5,000 of those capital expenditures estimated for the calendar years 2002, 2003 and 2004, respectively. The corresponding capital expenditures to achieve the estimated future pre-tax net cash flows from the Established Reserves, Proved Reserves and Probable Reserves based on constant cost and price assumptions are \$235,000 (\$203,000 if discounted by 15% per annum) with \$Nil, \$225,000 and \$5,000 of those capital expenditures estimated for the calendar years 2002, 2003 and 2004, respectively.
- (9) The extent and character of the interests evaluated in the McDaniel Report and all factual data was supplied by the Initial Properties Vendors to McDaniel and were accepted by McDaniel as represented. The crude oil and natural gas reserve calculations and any projections on which the McDaniel Report is based were determined with generally accepted petroleum engineering evaluation practices.
- (10) The constant cost and price evaluation was based on the average yearly general product prices for 2002 as forecast in the escalated cost and price valuation (see note 11) adjusted for transportation and quality differentials to wellhead prices as set forth below:

Crude oil (WTI)	U.S. \$25.00/Bbl
Heavy oil	\$25.00/Bbl
Propane	\$25.20/Bbl
Butane	\$24.70/Bbl
Pentanes Plus	\$37.50/Bbl
Natural Gas	\$4.50/Mcf

Operating and capital costs were not escalated in the constant cost and price evaluation.

- (11) In respect of the escalated cost and price valuation, the average yearly general product prices utilized in the McDaniel Report for natural gas, crude oil and natural gas liquids, are outlined in the following table.

Year	Light Crude Oil			Natural gas Liquids at Edmonton		
	Heavy Crude Oil \$/Bbl	WTI Cushing Oklahoma* \$/Bbl	Edmonton Par 40° API \$/Bbl	Propane \$/Bbl	Butane \$/Bbl	Edmonton NGL Mix \$/Bbl
2002 (forecast 6 mth)	25.00	25.00	37.50	25.20	24.70	27.50
2003	24.10	23.50	35.10	24.70	23.10	26.20
2004	21.00	21.80	32.00	23.10	21.10	24.20
2005	21.10	22.20	32.10	23.00	21.20	24.20
2006	21.20	22.60	32.20	23.00	21.20	24.20
2007	21.90	23.10	32.90	23.40	21.70	24.70
2008	22.60	23.60	33.60	23.60	22.20	25.10
2009	23.30	24.10	34.30	24.00	22.60	25.60
2010	24.00	24.60	35.00	24.50	23.10	26.10
2011	24.70	25.10	35.70	25.00	23.50	26.60
2012	25.40	25.60	36.40	25.50	24.00	27.20
2013	26.10	26.10	37.10	26.10	24.50	27.70
2014	26.80	26.60	37.80	26.40	24.90	28.20
2015	27.60	27.10	38.60	27.00	25.50	28.80
2016	28.30	27.60	39.30	27.50	25.90	29.30
2017	29.10	28.20	40.10	28.20	26.40	30.00
2018	30.00	28.80	41.00	28.70	27.00	30.60
2019	30.80	29.40	41.80	29.30	27.60	31.20
2020	31.70	30.00	42.70	29.90	28.20	31.90
2021	32.50	30.60	43.50	30.50	28.70	32.50
Thereafter	32.50	30.60	43.50	30.50	28.70	32.50

* 40 degree API, 0.4% sulphur.

Year	Henry Hub SU.S./MMBTU	AECO Spot \$/GJ	Alberta Spot \$/MMBTU
2002	3.36	4.39	4.50
2003	3.53	4.62	4.70
2004	3.46	4.44	4.55
2005	3.48	4.40	4.50
2006	3.51	4.36	4.45
2007	3.54	4.40	4.50
2008	3.58	4.44	4.50
2009	3.62	4.48	4.55
2010	3.69	4.57	4.65
2011	3.77	4.67	4.75
2012	3.84	4.76	4.85
2013	3.92	4.85	4.95
2014	3.99	4.94	5.00
2015	4.07	5.04	5.10
2016	4.14	5.13	5.20
2017	4.23	5.24	5.35
2018	4.32	5.35	5.45
2019	4.41	5.47	5.55
2020	4.50	5.58	5.65
2021	4.59	5.69	5.80
Thereafter.....	4.59	5.69	5.80

Operating and capital costs have been escalated at 2% annually.

(12) All of the Proved Producing Reserves are currently on production.

The McDaniel Report will be available for inspection at the head office of the Corporation, Suite 2400, 500 - 4th Avenue S.W., Calgary, Alberta, T2P 2V6, during normal business hours during the period of distribution and for 30 days thereafter.

Summary of Selected Reserve Information

The following table sets forth the interest acquired, gross reserves, Economic Life and Reserve Value information respecting the Initial Properties as at August 1, 2002.

Property	% Interest Acquired ⁽¹⁾⁽²⁾	Gross Reserves (MBOE) ⁽²⁾⁽³⁾	Economic Life (years) ⁽²⁾⁽³⁾	Reserve Value ⁽²⁾⁽³⁾⁽⁴⁾⁽⁵⁾	
				(\$000's)	%
Thompson Lake	99	2,449	7	20,765	47.7
Bellshill Lake	100	833	10	5,660	13.0
David North	100	1,036	10	14,664	33.7
Metiskow	100	183	7.5	1,500	3.5
Other	32	72	7	926	2.1
TOTAL ⁽⁶⁾	99	4,573	8.3 ⁽⁷⁾	43,515	100.0

Notes:

- (1) The weighted average percentage interest share of Established Reserves acquired by the Corporation from the Initial Properties Vendors before the deduction of royalties payable to others (excluding the Trust).
- (2) Based on Established Reserves as derived from the McDaniel Report.
- (3) Utilizing escalating cost and price assumptions.
- (4) Discounted at 10%, before general and administrative expenses, interest costs, taxes, site restoration and abandonment costs.
- (5) Net of capital expenditures. Does not include the value of the Undeveloped Lands.
- (6) Columns may not add due to rounding.
- (7) Average of the Economic Life column.

Incremental Exploitation and Development Potential

Management of the Corporation has identified several opportunities to take advantage of possible development potential and increase existing production in the Initial Properties which are supplemental to the future development projects included in the determination of the Reserve Values contained in the McDaniel Report. Opportunities being considered include:

- an additional 10 development drilling locations at Thompson Lake;
- 20 well re-completions at David North to convert wells which have been producing in the Lloydminster and/or Dina zones to oil producers from the Cummings and Sparky formations;
- additional horizontal drilling locations which have been identified through a review of 3-D seismic over the Bellshill Lake property;
- drilling of vertical water injection wells and the addition of inclined free-water knockouts to increase water disposal capacity at Bellshill Lake which may bring onstream part of the approximately 180 Bbls/d of oil that is currently shut-in due to limited water handling capacity;
- the use of inclined free-water knockouts at Thompson Lake and David North to improve the cost efficiency of water injection on these properties; and
- there is potential for a new pool at Metiskow, with 3-D seismic supporting a horizontal drilling program.

Neither the capital costs nor the potential incremental production associated with these opportunities are reflected in the McDaniel Report.

The Corporation may also identify further development projects and other opportunities to optimize production from the Initial Properties and implement operational efficiencies to lower operating expenses from those forecasted in the McDaniel Report as it enhances its understanding of the operations of the Initial Properties.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells located on the Initial Properties as at August 1, 2002 in which the Corporation has an interest which are producing or which the McDaniel Report considers to be capable of production.

	Producing ⁽¹⁾⁽⁵⁾⁽⁶⁾				Shut-in ⁽¹⁾⁽²⁾			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross Wells ⁽³⁾	Net Wells ⁽⁴⁾	Gross Wells ⁽³⁾	Net Wells ⁽⁴⁾	Gross Wells ⁽³⁾	Net Wells ⁽⁴⁾	Gross Wells ⁽³⁾	Net Wells ⁽⁴⁾
Thompson Lake	192	190	–	–	27	26	–	–
David North	54	54	–	–	10	10	–	–
Bellshill Lake	18	18	–	–	9	9	–	–
Metiskow	5	5	–	–	6	6	–	–
TOTAL	269	267	–	–	52	51	–	–

Notes:

- (1) Based on information contained in the McDaniel Report.
- (2) "Shut-in" wells means wells which are not producing but which the McDaniel Report considers to be capable of production. Shut-in wells in which the Corporation has a working interest are located within a reasonable distance from or are already tied into gathering systems, pipelines or other means of transportation.
- (3) "Gross" wells are defined as the total number of wells in which the Corporation has a working interest.
- (4) "Net" wells are defined as the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest therein.
- (5) Royalty interest wells have been assigned a net number of zero.
- (6) Not all wells in which the Corporation has an interest have been assigned reserves in the McDaniel Report or included in this table. See "Description of the Trust – Reclamation Fund".

Production History

The sales volumes of crude oil and natural gas attributable to the Initial Properties, before deduction of royalties, for the periods indicated are summarized below. Average production for the month of September, 2002 was approximately 2,740 BOE/d.

	6 Month Period Ended June 30, 2002 ⁽¹⁾ (unaudited)	Year Ended December 31, ⁽¹⁾		
		2001 (unaudited)	2000 (unaudited)	1999 (unaudited)
Crude oil and natural gas liquids (Mbbbls)	484	1,065	1,238	1,249
Average daily production (Bbls/d)	2,673	2,917	3,393	3,423
Natural gas sales (Mmcf)	111	263	255	244
Average daily sales (Mcf/d)	611	719	700	668
Total oil equivalent (MBOE)	502	1,109	1,281	1,290
Average daily production (BOE/d)	2,775	3,037	3,510	3,534

Notes:

- (1) Based on information provided to the Corporation by the Initial Properties Vendors.

Drilling History

The following table sets forth the gross and net development wells in respect of the Initial Properties in which the Initial Properties Vendors participated during the periods indicated. The Initial Properties Vendors did not participate in any exploratory wells during such periods.

	Year Ended December 31, ⁽⁴⁾					
	2001		2000		1999	
	Gross Wells ⁽¹⁾⁽³⁾	Net Wells ⁽²⁾⁽³⁾	Gross Wells ⁽¹⁾⁽³⁾	Net Wells ⁽²⁾⁽³⁾	Gross Wells ⁽¹⁾⁽³⁾	Net Wells ⁽²⁾⁽³⁾
Development						
Oil	13	12.9	1	1.0	–	–
Natural Gas	–	–	1	1.0	1	1.0
Dry	1	1.0	–	–	–	–
TOTAL	14	13.9	2	2.0	1	1.0

Notes:

- (1) "Gross Wells" means the total number of wells in which the Corporation has a working interest.
- (2) "Net Wells" means the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest therein.
- (3) Royalty interest wells have been assigned a net number of zero.
- (4) Based on information provided to the Corporation by the Initial Properties Vendors. The Initial Properties Vendors did not own the Initial Properties for all of 1999 and, as a result, information with respect to drilling history for 1999 is not complete.

Capital Expenditures

The following table summarizes capital expenditures made by the Initial Properties Vendors on acquisitions, exploration and development drilling and production facilities and other equipment in respect of the Initial Properties for the periods indicated.

	Year Ended December 31, ⁽¹⁾		
	2001	2000	1999
	(unaudited) (\$000's)	(unaudited) (\$000's)	(unaudited) (\$000's)
Property acquisitions ⁽²⁾	–	18	–
Drilling ⁽³⁾	4,941	440	–
Abandonments	110	21	21
Production equipment ⁽⁴⁾	4,208	1,168	–
Workovers	986	394	–
TOTAL	10,245	2,041	21

Notes:

- (1) Based on information provided to the Corporation by the Initial Properties Vendors. The Initial Properties Vendors did not own the Initial Properties for all of 1999 and, as a result, information with respect to capital expenditures for 1999 is not complete.
- (2) Property acquisitions include production lease/royalty purchases and property exchanges of lease and royalty interests.
- (3) Drilling includes development drilling and miscellaneous intangible expenditures.
- (4) Production equipment includes production and facility equipment, pipelines and miscellaneous tangible assets.

Direct Revenue and Operating Expenses

The following table sets forth revenue and operating expenses directly attributable to the Initial Properties for the periods indicated.

	6 Month Period Ended June 30, 2002⁽¹⁾	Year Ended December 31, ⁽¹⁾		
	(unaudited) (\$000's)	2001	2000	1999
	(unaudited) (\$000's)	(\$000's)	(\$000's)	(\$000's)
Revenue:				
Petroleum and natural gas sales ⁽²⁾	13,935	30,675	46,395	30,506
Royalties	1,211	2,792	4,407	2,985
Operating expenses	5,050	11,587	9,333	7,266
Operating Income	<u>7,674</u>	<u>16,296</u>	<u>32,655</u>	<u>20,255</u>

Notes:

- (1) See "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999" included in this prospectus.
- (2) Average product prices received: 2002 - \$27.74/BOE; 2001 - \$27.66/BOE; 2000 - \$36.22/BOE; and 1999 - \$23.65/BOE, based on information provided to the Corporation by the Initial Properties Vendors.

ADDITIONAL PROPERTIES

Acquisition of Additional Properties and Additional Direct Royalties

On August 1, 2002, the Corporation entered into the Additional Properties Agreement with Anadarko Canada Corporation to purchase the Additional Properties and the Additional Direct Royalties for a purchase price of \$71.8 million, prior to adjustments. The effective date of the acquisition of the Additional Properties and the Additional Direct Royalties was June 1, 2002, and the acquisition closed on November 15, 2002. The Additional Properties Acquisition Cost of \$53.2 million was funded by an advance under the Current Bank Facility, and indirectly through an additional advance under the Interim Loan. The Trust will use approximately \$23.4 million from the net proceeds of the Offering to repay the Interim Loan (including accrued interest) and approximately \$4.2 million from the net proceeds of the Offering to partially repay the advance made under the Current Bank Facility which was used to partially fund the Additional Properties Acquisition. See "Information

Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan", "Capitalization of the Trust" and "Use of Proceeds".

The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional \$5.7 million adjustment to the Additional Properties Acquisition Cost should be made in favour of the Additional Properties Vendor. This dispute relates to whether or not the value of a hedging contract held by the Additional Properties Vendor impacts the net proceeds from the Additional Properties from the effective date of the Additional Properties Acquisition of June 1, 2002 to the closing date of November 15, 2002. The Additional Properties Vendor has indicated its intent to charge the Corporation the additional \$5.7 million as an interim adjustment within 90 days of the closing of the Additional Properties Acquisition. Management of the Corporation believes that such amount is not owing to the Additional Property Vendor. This dispute is expected to be resolved through an arbitration process established in the Additional Properties Agreement. See "Risk Factors".

Description Of Additional Direct Royalties

As part of the Additional Properties Acquisition, the Corporation acquired a minor gross overriding royalty interest in ¼ of a section in the Hayter area to which the Corporation has assigned a \$55,000 value. The Additional Direct Royalties were then sold to the Trust from the Corporation for \$55,000 pursuant to a Direct Royalties Sale Agreement.

Description of Additional Properties

The Additional Properties are located in East Central Alberta, the same area as the Initial Properties. The major fields are Hayter and West Provost, both of which are operated by the Additional Properties Vendor. The McDaniel Report has assigned 8,155 MBOE of Established Reserves to the Additional Properties, before deduction of royalties. **Unless otherwise indicated all information set forth below is net to the Corporation.**

Hayter

Pursuant to the Additional Properties Acquisition, the Corporation acquired an average 95% working interest and has assumed operatorship in this area which is currently producing approximately 5,770 Bbls/d of 15° API oil from the Dina "B" Pool located in Sections 24, 25, 34 and 35-40-1 W4M. The McDaniel Report has assigned 7,203 MBOE of Established Reserves, before deduction of royalties, to this area. The Hayter pool contains 149 gross producing wells. OOIP is 138,000 MBOE with only 18,900 MBOE (14%) produced to date.

The wells in this area produce from a high quality, thick lower Cretaceous channel sand that is underlain by an active aquifer. The high quality of the Hayter pool is characterized by porosity of approximately 30% and average permeability ranging from 2 - 5 Darcies. To take advantage of the reserve recovery benefits of the aquifer, the pool has been developed using horizontal wells. The use of horizontal wells has proven to be effective in maximizing recovery from this and many similar pools in the area. The wells in this area are equipped with progressive cavity pumps to maximize fluid production. The Hayter fluid production in the area is gathered into one of two central batteries located at 8-35-40-1 W4M or 1-34-40-1 W4M in which the Corporation has a 95% working interest and operates. 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 Husky 8-14-39-03 W4.

The McDaniel Report has assigned Non-Producing Reserves to 23 horizontal wells in the Dina pool, resulting in an average forecast ultimate recovery of 19%.

Management of the Corporation believes, based upon its assessment of the Hayter area, that there are also opportunities to improve the gathering and processing of produced fluid. De-bottlenecking field gathering systems and processing facilities may serve to increase fluid handling capacity, resulting in increased oil production and reduced operating costs.

Future development of this pool may also include additional in-fill drilling on closer spacing, pool extensions through the identification of by-pass 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, similar to the Initial Properties, employing inclined free-water knockouts.

West Provost

Pursuant to the Additional Properties Acquisition, the Corporation acquired an average 37.5% working interest in this area and has assumed operatorship, which is currently producing approximately 650 BOE/d of primarily 26° API oil, at a 98% water cut, primarily from the Mannville "L" Pool located in Twps. 37, 38 and 39-3 W4M. Current natural gas production is approximately 200 Mcf/d. The McDaniel Report has assigned 952 MBOE of Established Reserves, before deduction of royalties, to this area. The West Provost pool contains 114 gross (43 net) producing oil wells and 15 gross (6 net) producing natural gas wells.

The Mannville "L" Pool was first discovered in 1976 with the drilling of the 11-15-38-3 W4M well. The pool was subsequently developed using vertical wells. Since 1993 the pool has been developed almost exclusively using directional wells drilled from central pad locations. The area also produces oil from five vertical oil wells developed in the Rex formation. The wells in this area are equipped with progressive cavity pumps to maximize fluid production. All oil wells are tied into one of two operated batteries. The West Provost area also produces natural gas from 15 gross wells, primarily from the Viking and Colony Formations.

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 Corporation anticipates acquiring 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 Gas Plant at 8-14-39-03 W4M.

The Corporation anticipates that there may be an opportunity to selectively drill horizontal wells within structurally high areas in the pool. There is also an opportunity to employ cost reduction practices to improve netbacks and ultimate recovery, similar to the Initial Properties, employing inclined free-water knockouts.

Undeveloped Lands

Approximately 22,447 (8,707 net) acres of Undeveloped Lands were acquired by the Corporation from the Additional Properties Vendor as part of the Additional Properties Acquisition. The Corporation has assigned a value of \$435,000 to these Undeveloped Lands. The Corporation intends to conduct a review of available seismic and other data and develop an exploitation plan regarding these Undeveloped Lands. Capital expenditures, Farmouts or dispositions may result in future revenues from these Undeveloped Lands. The geographical area and value assigned by the Corporation to the Undeveloped Lands is as follows:

<u>Property</u>	<u>Gross Area (Acres)</u>	<u>Net Area (Acres)</u>	<u>Assigned Value</u>
Hayter	8,142	3,342	\$167,000
West Provost	14,305	5,365	\$268,000
TOTAL	22,447	8,707	\$435,000

Marketing Arrangements

All of the oil production from the Additional Properties is shipped into the Bow River stream on the Gibson Provost pipeline system. Gibson Energy Ltd. supplies condensate required for blending on the Provost system and invoices the producer. The percentage of condensate required ranges from 15 to 25% of produced oil depending on the season, with more condensate required in the winter months.

As part of the closing of the Additional Properties Acquisition, the Corporation entered into a physical contract to deliver 6,000 Bbls/d of Lloydminster blend crude oil to Anadarko until December 31, 2003. This will require that the Corporation purchase approximately 1,000 Bbls/d of condensate to blend with its production to meet the oil quality requirements at the delivery point. Under the contract, the Corporation will be paid the NYMEX calendar WTI price less a fixed differential of U.S. \$8.233 per Bbl, such price not to be less than U.S.\$14.40 per Bbl or greater than U.S.\$17.244 per Bbl. In effect, this contract applies a fixed differential to a WTI price collar between U.S. \$22.633 and U.S.\$25.477 per Bbl. The contract will be effective until December 31, 2003.

Solution natural gas produced is conserved, and then processed at a third party sour gas plant. Non-associated natural gas is sold under two different contracts. The first is an aggregator natural gas purchase contract with TransCanada PipeLines for the life of the reserves and the second is a 30-day evergreen contract using AECO spot pricing.

Oil and Natural Gas Reserves

McDaniel has prepared the McDaniel Report dated August 21, 2002, evaluating as at June 1, 2002 the crude oil, natural gas and natural gas liquids reserves attributable to the Additional Properties, which evaluation has been mechanically updated only to August 1, 2002. **The McDaniel Report evaluates the crude oil, natural gas and natural gas liquids reserves attributable to the Additional Properties and the Additional Direct Royalties prior to provision for income taxes, interest costs (including Debt Service Charges), general and administrative expenses (including General and Administrative Costs) facility site restoration, well abandonment and well site restoration costs, but after providing for estimated royalties, operating costs, and future capital expenditures. The probable reserves and the present worth value of such reserves as set forth in the tables below have been reduced by 50% to reflect the degree of risk associated with recovery of such reserves. It should not be assumed that the discounted future net production revenues estimated by McDaniel represent the fair market value of the reserves.** Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes following the tables.

Additional Properties Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows Escalating Cost and Price Case

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas ⁽²⁾ (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows (\$000's) ⁽¹⁾⁽²⁾⁽³⁾⁽⁵⁾ Discounted at			
	Gross ⁽²⁾	Net ⁽²⁾	Gross ⁽²⁾	Net ⁽²⁾	0%	10%	15%	20%
	Proved Reserves ⁽²⁾							
Producing Reserves ⁽²⁾	5,354	4,556	320.0	255.2	51,922	44,721	42,002	39,691
Non-Producing Reserves ⁽²⁾	1,867	1,532	—	—	17,173	13,481	12,049	10,819
Total Proved Reserves ⁽²⁾	7,221	6,088	320.0	255.2	69,095	58,202	54,051	50,510
Risked Probable Reserves ⁽²⁾	879	741	9.6	6.7	9,484	6,797	5,915	5,223
Established Reserves ⁽²⁾	8,100	6,829	329.6	261.9	78,579	64,999	59,966	55,733

Additional Properties Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows Constant Cost and Price Case

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas ⁽²⁾ (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows (\$000's) ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Discounted at			
	Gross ⁽²⁾	Net ⁽²⁾	Gross ⁽²⁾	Net ⁽²⁾	0%	10%	15%	20%
	Proved Reserves ⁽²⁾							
Producing Reserves ⁽²⁾	5,354	4,552	320.0	255.2	65,595	54,932	50,985	47,672
Non-Producing Reserves ⁽²⁾	1,867	1,532	—	—	20,779	16,330	14,615	13,147
Total Proved Reserves ⁽²⁾	7,221	6,083	320.0	255.2	86,374	71,262	65,600	60,819
Risked Probable Reserves ⁽²⁾	879	740	9.6	6.7	12,178	8,533	7,349	6,427
Established Reserves ⁽²⁾	8,100	6,823	329.6	261.9	98,552	79,795	72,949	67,246

Notes:

- (1) Columns may not add due to rounding.
- (2) See Notes (2) to (7) and (9) of "Initial Properties – Oil and Natural Gas Reserves".
- (3) The McDaniel Report estimates total capital expenditures (net to the Corporation) to achieve the estimated future pre-tax net cash flows from the Established Reserves, Proved Reserves and Probable Reserves based on escalating cost and price assumptions to be \$12,517,000 (\$12,064,000 if discounted by 15% per annum) with \$9,046,000, \$3,471,000 and \$Nil of those capital expenditures estimated for the calendar years 2002, 2003 and 2004, respectively. The corresponding capital expenditures to achieve the estimated future pre-tax net cash flows from the Established Reserves, Proved Reserves and Probable Reserves based on constant cost and price assumptions are \$12,449,000 (\$12,005,000 if discounted by 15% per annum) with \$9,046,000, \$3,403,000 and \$Nil of those capital expenditures estimated for the calendar years 2002, 2003 and 2004, respectively.
- (4) See Note (10) of "Initial Properties – Oil and Natural Gas Reserves".
- (5) See Note (11) of "Initial Properties – Oil and Natural Gas Reserves".

(6) Approximately 99% of the Proved Producing Reserves are currently on production.

Summary of Selected Reserve Information

The following table sets forth the interests acquired, gross reserves, Economic Life and Reserve Value information respecting the Additional Properties as at August 1, 2002.

Property	% Interest anticipated to be Acquired ⁽¹⁾⁽²⁾	Gross Reserves (MBOE) ^{(2) (3)}	Economic Life (years) ^{(2) (3)}	Reserve Value ^{(2) (3) (4) (5)}	
				(\$000's)	%
Hayter	95.0	7,203	10	56,156	86.4
West Provost	37.5	952	10	8,843	13.6
TOTAL ⁽⁶⁾	79.8	8,155	10⁽⁷⁾	64,999	100.0

Notes:

- (1) The weighted average percentage interest share of Established Reserves acquired by the Corporation from the Additional Properties Vendor before the deduction of royalties payable to others (other than the Trust).
- (2) Based on Established Reserves as derived from the McDaniel Report.
- (3) Utilizing escalating cost and price assumptions.
- (4) Discounted at 10%, before general and administrative expenses, interest costs, taxes, site restoration and abandonment costs.
- (5) Net of capital expenditures. Does not include the value of the Undeveloped Lands.
- (6) Columns may not add due to rounding.
- (7) Average of Economic Life column.

Incremental Exploitation and Development Potential

Management of the Corporation has identified several opportunities to take advantage of possible development potential and increase existing production in the Additional Properties which are supplemental to the future development projects included in the determination of the Reserve Values contained in the McDaniel Report. Opportunities being considered include:

- additional in-fill drilling potential exists at Hayter using shorter horizontal wells (200-300 metres in length), spaced at 20-25 metres to access reserves currently not being effectively depleted through existing wells. In 2001 and 2002, the operator of the property drilled several 20 metre inter-well distance wells at the "toe" of existing horizontal wells. Initial results from these wells are promising, with the original recoverable proved reserves estimated by McDaniel at 90 Mbbls per well;
- at Hayter, forecast ultimate recovery of 19% of the OOIP in the McDaniel Report is relatively low when compared to other pools of this type and quality;
- the Hayter property has fluid handling limitations, which can be reduced through gathering and processing facility de-bottlenecking; and
- at West Provost, there may be an opportunity to selectively drill horizontal wells within structurally high areas in the pool as well as an opportunity to employ cost reduction practices to improve netbacks and ultimate recovery.

Neither the capital costs nor the potential incremental production associated with these opportunities are reflected in the McDaniel Report.

The Corporation may also identify additional development projects and other opportunities to optimize production from the Additional Properties and implement operational efficiencies to lower operating expenses from those forecasted in the McDaniel Report once it has enhanced its understanding of the operations of the Additional Properties subsequent to gaining control of such operations.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells located on the Additional Properties as at August 1, 2002 in which the Corporation acquired an interest pursuant to the Additional Properties Agreement which are producing wells or which the McDaniel Report considers to be capable of production.

	Producing ⁽¹⁾⁽⁵⁾⁽⁶⁾				Shut-in ⁽¹⁾⁽²⁾			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross Wells ⁽³⁾	Net Wells ⁽⁴⁾	Gross Wells ⁽³⁾	Net Wells ⁽⁴⁾	Gross Wells ⁽³⁾	Net Wells ⁽⁴⁾	Gross Wells ⁽³⁾	Net Wells ⁽⁴⁾
Hayter	149	141.5	–	–	33	31.3	1	1.0
West Provost	114	42.7	15	5.6	13	4.9	1	0.4
TOTAL	263	184.2	15	5.6	46	36.2	2	1.4

Notes:

- (1) Based on information contained in the McDaniel Report.
- (2) "Shut-in Wells" means wells which are not producing but which the McDaniel Report considers to be capable of production. Shut-in Wells in which the Corporation acquired an interest are located within a reasonable distance from or are already tied into gathering systems, pipelines or other means of transportation.
- (3) "Gross Wells" are defined as the total number of wells in which the Corporation acquired a working interest.
- (4) "Net Wells" are defined as the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest acquired therein.
- (5) Royalty interest wells have been assigned a net number of zero.
- (6) Not all wells in which the Corporation acquired an interest have been assigned reserves in the McDaniel Report or are included in this table. See "Description of the Trust – Reclamation Fund".

Production History

The sales volumes of crude oil, natural gas, and natural gas liquids attributable to the Additional Properties, before deduction of royalties, for the periods indicated are summarized below. Average production for the month of September, 2002 was approximately 6,630 BOE/d.

	6 Month Period Ended June 30, 2002 ⁽¹⁾ (unaudited)	Year Ended December 31, ⁽¹⁾		
		2001 (unaudited)	2000 (unaudited)	1999 (unaudited)
Crude oil and natural gas liquids (Mbbbls)	1,284	2,873	2,404	2,077
Average daily production (Bbls/d)	7,098	7,872	6,587	5,689
Natural gas sales (Mmcf)	92	218	90	137
Average daily sales (Mcf/d)	507	596	246	374
Total oil equivalent (MBOE)	1,300	2,909	2,419	2,099
Average daily production (BOE/d)	7,182	7,971	6,628	5,750

Note:

- (1) Based on information provided to the Corporation by the Additional Properties Vendor.

Drilling History

The following table sets forth the gross and net exploratory and development wells in respect of the Additional Properties in which the Additional Properties Vendor participated during the periods indicated. The Additional Properties Vendor did not participate in any exploratory wells during such periods.

	Year Ended December 31, ⁽⁴⁾					
	2001		2000		1999	
	Gross Wells ⁽¹⁾	Net Wells ⁽²⁾⁽³⁾	Gross Wells ⁽¹⁾	Net Wells ⁽²⁾⁽³⁾	Gross Wells ⁽¹⁾	Net Wells ⁽²⁾⁽³⁾
Development						
Oil	21	19.6	26	23.4	10	9.1
Natural Gas	-	-	-	-	-	-
Dry	-	-	-	-	-	-
TOTAL	21	19.6	26	23.4	10	9.1

Notes:

- (1) "Gross Wells" means the number of wells in which the Corporation acquired a working interest.
- (2) "Net Wells" means the aggregate of the numbers obtained by multiplying each gross well by the percentage working interest acquired by the Corporation therein.
- (3) Royalty interest wells have been assigned a net number of zero.
- (4) Based on information provided to the Corporation by the Additional Properties Vendor.

Capital Expenditures

The following table summarizes capital expenditures made by the Additional Properties Vendor on acquisitions, development drilling and production facilities and other equipment in respect of the Additional Properties for the periods indicated.

	Year Ended December 31, ⁽¹⁾		
	2001	2000	1999
	(unaudited) (\$000's)	(unaudited) (\$000's)	(unaudited) (\$000's)
Property acquisitions ⁽²⁾	-	54	-
Development expenditures ⁽³⁾	12,373	14,941	5,095
Production equipment ⁽⁴⁾	4,518	3,915	521
TOTAL	16,891	18,910	5,616

Notes:

- (1) Based on information provided to the Corporation by the Additional Properties Vendor.
- (2) Property acquisitions include production lease/royalty purchases and property exchanges of lease and royalty interests.
- (3) Development expenditures include development drilling and miscellaneous intangible expenditures.
- (4) Production equipment includes production and facility equipment and miscellaneous tangible assets.

Direct Revenue and Operating Expenses

The following table sets forth revenue and operating expenses directly attributable to the Additional Properties for the periods indicated.

	6 Month	Year Ended December 31, ⁽¹⁾		
	Period Ended	2001	2000	1999
	June 30, 2002 ⁽¹⁾	2001	2000	1999
	(\$000's)	(\$000's)	(\$000's)	(\$000's)
	(unaudited)			
Revenue:				
Petroleum and natural gas sales ⁽²⁾	33,227	57,615	72,026	42,693
Royalties	6,474	11,340	14,465	7,268
Operating expenses	6,838	12,832	8,800	7,453
Operating Income	19,915	33,443	48,761	27,972

Notes:

- (1) See "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation Years ended December 31, 2001, 2000 and 1999" included in this prospectus.
- (2) Average product prices received: 2002 - \$25.56/BOE; 2001 - \$19.80/BOE; 2000 - \$29.77/BOE; and 1999 - \$20.34/BOE, based on information provided to the Corporation by the Additional Properties Vendor.

SELECTED PRO FORMA INFORMATION

The following pro forma information reflects combined information related to the Initial Properties and the Additional Properties. See "Initial Properties", "Additional Properties", "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Balance Sheet Harvest Energy Trust As at July 10, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at July 10, 2002 and for the six months ended June 30, 2002 and year ended December 31, 2001" included in this prospectus for a description of each group of properties and their related reserve information, production information and direct revenue and operating expenses.

Pro Forma Description of Properties

The Initial Properties and the Additional Properties are located in the same general area in east central Alberta near Lloydminster. The Initial Properties and the Additional Properties include interests in the following major oilfields: Hayter, Thompson Lake, David North, West Provost, Bellshill Lake and Metiskow. See "Initial Properties" and "Additional Properties".

The Initial Properties and the Additional Properties are operated by the Corporation. The Corporation has approximately a 99% working interest in the Initial Properties and a 95% and 37.5% working interest in the Hayter properties and the West Provost properties, respectively, included in the Additional Properties. The Corporation has Established Reserves (according to the McDaniel Report using escalating price and cost assumptions), before deduction of royalties, of 5,141 Mbbls of medium gravity crude oil, 7,203 Mbbls of heavy gravity crude oil, 82 Mbbls of natural gas liquids and 1,816 Mmcf of natural gas.

Associated with these Initial Properties and Additional Properties are 15,382 net acres of Undeveloped Land, 451 net producing oil wells, 6 net producing natural gas wells, 87 net shut-in oil wells and 1.4 net shut-in natural gas wells.

This portfolio of Properties has the following characteristics:

- (a) **Predictable Production Performance:** The production from the Initial Properties and Additional Properties is derived from several hundred wells, which in aggregate have demonstrated a stable and predictable production history.
- (b) **Operated:** If the Corporation is successful in replacing the Additional Properties Vendor as operator of the Additional Properties, the Corporation will be able to exercise management and operating control to enhance the value of the Properties for the benefit of the Trust. See "Information Respecting the Corporation – Operating Strategies".
- (c) **Concentrated:** The Initial Properties and Additional Properties are concentrated in a relatively small area in east central Alberta. Management of the Corporation believes this will enable the Corporation to gain benefits from economies of scale in managing the Initial Properties and Additional Properties and also enable the Corporation to effectively enhance the value of the Initial Properties and Additional Properties by applying experience gained from one property to the balance of the Properties.
- (d) **Development Potential:** The Initial Properties and Additional Properties have been operated by senior oil and natural gas producers in the past. Although the Initial Properties and Additional Properties have been subject to extensive drilling and development programs, management of the Corporation believes that there are opportunities to improve the production from and to further develop the Reserves associated with these Properties. See "Selected Pro Forma Information – Pro Forma Reserve Information" and "Selected Pro Forma Information – Pro Forma Incremental Exploitation and Development Potential".

Pro Forma Reserve Information

McDaniel has prepared the McDaniel Report dated August 21, 2002, evaluating as at August 1, 2002 the crude oil, natural gas and natural gas liquids reserves attributable to the Initial Properties and the Initial Direct Royalties and evaluating as at June 1, 2002, with a mechanical update only to August 1, 2002, the crude oil, natural gas and natural gas liquids reserves attributable to the Additional Properties and the Additional Direct Royalties. **The McDaniel Report evaluates the crude**

oil, natural gas and natural gas liquids reserves attributable to the Initial Properties and the Additional Properties prior to provision for income taxes, interest costs (including Debt Service Charges), general and administrative expenses (including General and Administrative Costs), facility site restoration, well abandonment and well site restoration costs, but after providing for estimated royalties, operating costs and future capital expenditures. The probable reserves and the present worth value of such reserves as set forth in the tables below have been reduced by 50% to reflect the degree of risk associated with recovery of such reserves. It should not be assumed that the discounted future net cash flows estimated by McDaniel represent the fair market value of these reserves. Additional assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes following the tables.

**Pro Forma Petroleum and Natural Gas
Reserves and Pre-Tax Net Cash Flows
Escalating Cost and Price Case**

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows (\$000's) ⁽¹⁾⁽²⁾ Discounted at			
	Gross ⁽¹⁾⁽²⁾	Net ⁽¹⁾⁽²⁾	Gross ⁽¹⁾⁽²⁾	Net ⁽¹⁾⁽²⁾	0%	10%	15%	20%
	Proved Reserves ⁽²⁾							
Producing Reserves ⁽²⁾	9,251	8,225	1,348.3	1,078.8	99,174	83,660	77,911	73,079
Non-Producing Reserves ⁽²⁾	1,903	1,565	298.1	232.9	18,378	14,416	12,882	11,567
Total Proved Reserves ⁽²⁾	11,154	9,790	1,646.4	1,311.7	117,552	98,076	90,793	84,646
Risked Probable Reserves ⁽²⁾	1,272	1,113	169.9	133.1	15,200	10,439	8,927	7,763
Established Reserves ⁽²⁾	12,426	10,903	1,816.2	1,444.8	132,752	108,515	99,720	92,409

Notes:

- (1) Columns may not add due to rounding.
- (2) See Notes (2) through (11) to "Initial Properties – Oil and Natural Gas Reserves" and Note 3 to "Additional Properties – Oil and Natural Gas Reserves".

**Pro Forma Petroleum and Natural Gas
Reserves and Pre-Tax Net Cash Flows
Constant Cost and Price Case**

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows (\$000's) ⁽¹⁾⁽²⁾ Discounted at			
	Gross ⁽¹⁾⁽²⁾	Net ⁽¹⁾⁽²⁾	Gross ⁽¹⁾⁽²⁾	Net ⁽¹⁾⁽²⁾	0%	10%	15%	20%
	Proved Reserves ⁽²⁾							
Producing Reserves ⁽²⁾	9,254	8,218	1,349.0	1,079.4	127,416	104,243	95,835	88,860
Non-Producing Reserves ⁽²⁾	1,903	1,564	298.1	232.9	22,139	17,376	15,544	13,978
Total Proved Reserves ⁽²⁾	11,157	9,782	1,647.1	1,312.3	149,555	121,619	111,379	102,838
Risked Probable Reserves ⁽²⁾	1,272	1,112	169.9	133.1	19,508	13,092	11,075	9,534
Established Reserves ⁽²⁾	12,429	10,893	1,817.0	1,445.4	169,063	134,711	122,454	112,372

Notes:

- (1) Columns may not add due to rounding.
- (2) See Notes (2) through (11) to "Initial Properties – Oil and Natural Gas Reserves" and Note 3 to "Additional Properties – Oil and Natural Gas Reserves".

**Estimated Pre-Tax Net Cash Flows – Established Reserves of Pro Forma Properties
Escalating Cost and Price Case ⁽¹⁾
(Dollar amounts in thousands)**

Year	Annual Production (MBOE)	Company Interest Revenue	Royalty Burdens ⁽²⁾	Operating Expenses	Other Income	Net Operating Income	Net Capital Investment	Net Cash Flow ⁽³⁾⁽⁴⁾
2002	1,326.0	\$ 36,774	\$ 5,551	\$ 8,950	\$ 22	\$ 22,296	\$ 9,046	\$ 13,250
2003	3,283.7	86,530	13,593	22,086	36	50,886	3,701	47,186
2004	2,365.1	55,833	7,706	21,897	32	26,262	5	26,257

<u>Year</u>	<u>Annual Production (MBOE)</u>	<u>Company Interest Revenue</u>	<u>Royalty Burdens ⁽²⁾</u>	<u>Operating Expenses</u>	<u>Other Income</u>	<u>Net Operating Income</u>	<u>Net Capital Investment</u>	<u>Net Cash Flow ^{(3) (4)}</u>
2005	1,791.0	42,877	5,398	21,187	29	16,321	5	16,316
2006	1,338.0	32,567	3,804	18,206	25	10,582	—	10,582
2007	956.5	24,357	2,620	14,171	—	7,566	—	7,566
2008	697.2	18,366	1,872	11,290	—	5,204	—	5,204
2009	489.8	13,187	1,314	8,454	—	3,419	—	3,419
2010	261.1	7,152	716	4,836	—	1,600	—	1,600
2011	160.3	4,485	454	3,164	—	866	—	866
2012	38.7	1,204	87	804	—	313	—	313
2013	12.7	409	31	241	—	138	—	138
2014	2.8	92	14	52	—	26	—	26
2015	1.8	59	12	34	—	14	—	14
2016	1.6	54	11	34	—	8	—	8
Remainder	<u>2.3</u>	<u>58</u>	<u>12</u>	<u>36</u>	<u>—</u>	<u>10</u>	<u>—</u>	<u>9</u>
Total	<u>12,728.7</u>	<u>\$ 324,003</u>	<u>\$ 43,197</u>	<u>\$ 135,441</u>	<u>\$ 144</u>	<u>\$ 145,510</u>	<u>\$ 12,757</u>	<u>\$ 132,752</u>

Notes:

- (1) Numbers may not agree with the McDaniel Report and columns may not add due to rounding.
- (2) Includes mineral taxes.
- (3) Undiscounted.
- (4) Net cash flow before income taxes, interest, general and administrative expenses and estimated site restoration and abandonment costs.

Pro Forma Incremental Exploitation and Development Potential

Management of the Corporation has identified several opportunities to take advantage of possible development potential and increase existing production in the Initial Properties and the Additional Properties which are supplemental to the future development projects included in the determination of the Reserve Value contained in the McDaniel Report. A summary of the opportunities being considered are noted below. See "Initial Properties – Incremental Exploitation and Development Potential" and "Additional Properties – Incremental Exploitation and Development Potential" for a more detailed discussion of these opportunities.

- **Hayter:** Drilling additional in-fill wells using shorter horizontal wells (200-300 metres in length), spaced at 20-25 metres to access reserves currently not being effectively depleted through existing wells.
- **West Provost:** Potential opportunity to selectively drill horizontal wells within structurally high areas in the pool.
- **Thompson Lake:** Drilling 10 additional development locations.
- **David North:** Undertaking 20 well re-completions to convert wells which have been producing in the Lloydminster and/or Dina zones to oil producers from the Cummings and Sparky formations.
- **Bellshill Lake:** Drilling additional horizontal wells which have been identified through a review of 3-D seismic data.

Neither the capital costs nor the potential incremental production associated with these opportunities are reflected in the McDaniel Report.

The Corporation may also identify further development projects and other opportunities to optimize production from the Initial Properties and the Additional Properties and implement operational efficiencies to lower operating expenses from those forecasted in the McDaniel Report as it enhances its understanding of the operations of the Initial Properties and the Additional Properties.

Selected Pro Forma Production Information

The sales volumes of crude oil, natural gas, and natural gas liquids attributable to the Initial Properties and the Additional Properties, before deduction of royalties, for the periods indicated are summarized below. Average production for the month of September, 2002 was approximately 9,380 BOE/d.

	6 Month Period Ended June 30, 2002⁽¹⁾ (unaudited)	Year Ended December 31, ⁽¹⁾		
		2001 (unaudited)	2000 (unaudited)	1999 (unaudited)
Crude oil and natural gas liquids (Mbbbls)	1,768	3,938	3,642	3,326
Average daily production (Bbbls/d)	9,771	10,789	9,980	9,112
Natural gas sales (Mmcf)	203	481	345	381
Average daily sales (Mcf/d)	1,118	1,315	946	1,042
Total oil equivalent (MBOE)	1,802	4,018	3,700	3,389
Average daily production (BOE/d)	9,957	11,008	10,138	9,284

Notes:

- (1) Based on information provided to the Corporation by the Initial Properties Vendors in respect of the Initial Properties and the Additional Properties Vendor in respect of the Additional Properties.
- (2) See Notes to "Initial Properties – Production History" and "Additional Properties – Production History".

Pro Forma Direct Revenue and Operating Expenses

The following table sets forth revenue and operating expenses directly attributable to the Initial Properties and the Additional Properties for the periods indicated.

	6 Month Period Ended June 30, 2002⁽¹⁾ (unaudited)	Year Ended December 31, ⁽¹⁾⁽²⁾		
		2001 (unaudited)	2000 (unaudited)	1999 (unaudited)
Revenue:				
Petroleum and natural gas sales ⁽¹⁾	47,162	88,290	118,422	73,199
Royalties	7,685	14,132	18,872	10,253
Operating expenses	11,888	24,419	18,133	14,719
Operating Income	<u>27,589</u>	<u>49,739</u>	<u>81,417</u>	<u>48,227</u>

Notes:

- (1) See "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Balance Sheet Harvest Energy Trust As at July 10, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at July 10, 2002 and for the six months ended June 30, 2002 and year ended December 31, 2001" included in this prospectus.
- (2) See Notes to "Initial Properties – Direct Revenue and Operating Expenses" and "Additional Properties – Direct Revenue and Operating Expenses".

Pro Forma Cash Available For Distribution

The following is a summary of selected pro forma financial information for the oil and natural gas assets owned, directly or indirectly, by the Corporation for the period indicated.

Management of the Corporation have provided the following analysis to assist the Trust in analyzing the income of the Trust and the amounts of Cash Available For Distribution that would be available to the Trust for distribution to Unitholders had the Trust been in existence for the six month period ended June 30, 2002. This analysis was prepared on the assumption that the acquisition of the Initial Properties and the Additional Properties and any Direct Royalties associated with such Properties, had all been completed at the beginning of such period. Although firm commitments do not exist for all of the general and administrative expenses and, accordingly, the financial effect of the inclusion of all necessary general and administrative expenses is not at present determinable, management of the Corporation has, based upon their review of the amounts of these expenses in similar circumstances, estimated that these expenses would not deviate materially from the amount shown below.

The pro forma information is not a forecast or a projection of future results. The actual results of operations of the Trust for any period following completion of the Offering will vary from the amount set forth in the following analysis, and such variation may be material.

	Six Months Ended June 30, 2002		
	Initial Properties ⁽³⁾	(unaudited) Additional Properties ⁽⁴⁾	Total Pro Forma ⁽⁵⁾
Revenue (\$000 except per Unit)			
Oil and natural gas ⁽⁹⁾	\$ 13,935	\$ 33,227	\$ 47,162
less: Royalties	(1,211)	(6,474)	(7,685)
			<u>39,477</u>
Expenses			
Operating Expense	5,050	6,838	11,888
General and Administrative Expense			1,622
Interest Expense ⁽⁶⁾			1,534
Amortization of Deferred Charges			812
Depletion, Depreciation and Site Restoration			12,972
Total Expenses			<u>28,828</u>
Income Before Taxes			10,649
Capital Taxes			95
Net Income for Period			10,554
Net Income Per Unit			\$1.21 per Trust Unit
Add back (deduct)			
Amortization of Deferred Charges			812
Depletion, Depreciation and Amortization			12,972
Contribution to Reclamation Fund ⁽⁷⁾			(750)
Cash Available For Distribution			<u>23,588</u>
Increase in Capital Fund ⁽⁸⁾			<u>(11,794)</u>
Distributable Cash			11,794
Number of Units Outstanding			8,750,000
Distributable Cash per Trust Unit			\$1.35 per Trust Unit

Notes:

- (1) Cash Available For Distribution is not an earnings measure recognized by Canadian generally accepted accounting principles and is not necessarily comparable to the measurement of Cash Available For Distribution in other energy trust entities.
- (2) This pro forma financial information is based on production of 9,957 BOE/d being derived from the Initial Properties and the Additional Properties, based on information provided by the Initial Properties Vendors and the Additional Properties Vendor. McDaniel estimates the average production associated with the Established Reserves at 8,667 BOE/d for the period August 1, 2002 to December 31, 2002 and 8,996 for the 12 months ending December 31, 2003.
- (3) See "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999" included in this prospectus.
- (4) See "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation Years ended December 31, 2001, 2000 and 1999" included in this prospectus.
- (5) See "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Balance Sheet Harvest Energy Trust As at July 10, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at July 10, 2002 and for the six months ended June 30, 2002 and year ended December 31, 2001" included in this prospectus.
- (6) Assumes amounts outstanding under the Current Bank Facility of \$52.5 million. The Trust intends to use approximately \$23.4 million from the net proceeds of the Offering to repay the Interim Loan (including accrued interest) and approximately \$4.2 million from the net proceeds of the Offering to partially repay the advance made under the Current Bank Facility which was

used to partially fund the Additional Properties Acquisition. The resulting amount outstanding under the Current Bank Facility following closing of the Offering will result in a pro forma interest expense similar to that reflected in the table above. See "Use of Proceeds", "Additional Properties", "Risk Factors", "Description of the Trust – Interim Loan", "Information Respecting the Corporation – Borrowing", "Capitalization of the Trust" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at July 10, 2002 and for the six months ended June 30, 2002 and year ended December 31, 2001" included in this prospectus.

- (7) Based on an assumed \$1.5 million contribution to the Reclamation Fund in the first year of operations following Closing of the Offering. See "Description of the Trust – Reclamation Fund".
- (8) For purposes of this pro forma estimate of Distributable Cash, 50% of estimated Cash Available for Distribution has been assumed to have been retained in the Capital Fund. See "Description of the Trust – Capital Fund".
- (9) The oil and natural gas revenue does not reflect the impact of the Corporation's existing commodity hedges (see "Information Respecting the Corporation – Commodity Hedging"), or the physical contract for delivery of crude oil entered into on closing of the Additional Properties Acquisition (see "Additional Properties – Marketing Arrangements").

The information set forth is provided for illustrative purposes only and should not be construed as a forecast or projection. No assurance can be given that the Cash Available For Distribution shown in this analysis will ever be available or realized or that the assumptions of fact made are the most likely to occur. There can be no assurance that the oil production, oil prices, royalty rates, operating expenses and other costs recorded by the Trust will be as assumed.

DESCRIPTION OF THE TRUST

General

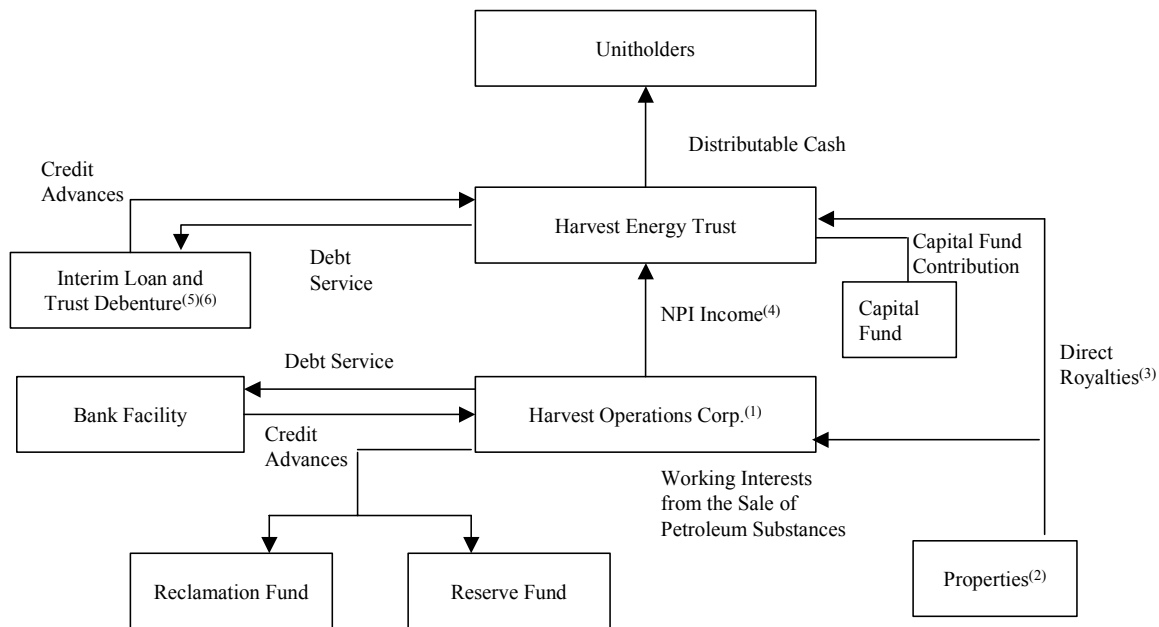
The Trust is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta and created pursuant to the Trust Indenture. The head and principal office of the Trust is located at Suite 2400, 500 - 4th Avenue S.W., Calgary, Alberta, T2P 2V6. The Trust is not managed 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 Direct Royalties (including the Initial Direct Royalties and the Additional Direct Royalties);
- (b) making payments to the Corporation pursuant to the Deferred Purchase Price Obligation under the NPI Agreement;
- (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.

Structure of the Trust

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



Notes:

- (1) A wholly-owned subsidiary of the Trust. See "Information Respecting the Corporation".
- (2) The Corporation owns the Initial Properties and the Additional Properties and may acquire or dispose of other Properties from time to time. See "Acquisition of NPI", "Initial Properties" and "Additional Properties".
- (3) In addition to the NPI, the Trust holds the Initial Direct Royalties and the Additional Direct Royalties. See "Description of the Trust – NPI and Direct Royalties", "Acquisition of NPI", "Initial Properties" and "Additional Properties". Direct Royalties are also anticipated to include other royalty interests acquired by the Trust from time to time.
- (4) Pursuant to the NPI Agreement, the Corporation will make regular monthly payments to the Trust in the amount of NPI Income. See "Description of the Trust – NPI and Direct Royalties".
- (5) The Trust intends to use approximately \$23.4 million from the net proceeds of the Offering to repay the Interim Loan (including accrued interest) and approximately \$4.2 million from the net proceeds of the Offering to partially repay the advance made under the Current Bank Facility which was used to partially fund the Additional Properties Acquisition. See "Description of the Trust – Interim Loan", "Information Respecting the Corporation – Borrowing", "Capitalization of the Trust", "Use of Proceeds" and "Interests of Management and Others in Material Transactions".
- (6) An aggregate of 5,000,000 Trust Units may be issuable upon settlement of the Trust Debenture. See "Description of the Trust – Trust Debenture", "Description of the Trust – Warrants", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".
- (7) The Trust intends to retain up to 50% of the Cash Available For Distribution in its Capital Fund to finance future acquisitions and development of the Properties.

NPI and Direct Royalties

Overview

The Corporation and the Trust have entered into the NPI Agreement, pursuant to which the Corporation has granted and set out to the Trust the right to receive the NPI Income on Properties held by the Corporation from time to time, including the Initial Properties and the Additional Properties.

The NPI consists of the right to receive a monthly payment from the Corporation equal to the NPI Income, which in respect of any period for which NPI Income is calculated, means 99% of production revenues from the Properties less 99% of the amount by which all NPI Deductions for such period exceeds Future Acquisition Costs paid with the proceeds from the sale of Properties, withdrawals from the Reserve Fund or Reclamation Fund to fund payment of NPI Deductions and advances made pursuant to the Credit Facilities to fund the payment of NPI Deductions. NPI Deductions paid as part of the Deferred Purchase Price Obligation are credited to the NPI Deductions.

Pursuant to the NPI Agreement substantially all of the economic benefit derived from the assets of the Corporation accrues to the benefit of the Trust and ultimately to the Unitholders. The term of the NPI Agreement will be for so long as there are Petroleum and Natural Gas Rights to which the NPI Agreement applies.

The residual 1% share of gross proceeds from the sale of Production which does not form part of NPI Income and is retained by the Corporation, together with any income of the Corporation 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), will be used to defray certain expenses and capital expenditures of the Corporation.

Pursuant to the NPI Agreement, the Corporation will be required to pay the Trust NPI Income received by the Corporation from the Properties during the month on or before the 15th day of the next calendar month. In calculating the NPI Income, the Corporation will deduct, among other costs and expenses, any amounts paid into the Reserve Fund and the Reclamation Fund. See "Description of the Trust – Reserve Fund" and "Description of the Trust – Reclamation Fund".

As consideration for granting the NPI, the Trust must pay to the Corporation 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.

If the Corporation wishes to dispose of any Properties which will result in proceeds in excess of \$10 million, the Harvest Board is required to approve such disposition, however, if the disposition represents all or substantially all of the Properties, such disposition must be approved by a Special Resolution of the Unitholders.

The Initial Properties and Additional Properties include working interests in a number of oil treating, natural gas gathering, natural gas compression and natural gas processing facilities. There may be opportunities for the Corporation to provide services to third parties with regard to the Corporation's available capacity in those facilities. Any income from providing any of these processing, gathering, disposal or treating services will not be included in the calculation of NPI Income but will be used to defray certain expenses and capital expenditures of the Corporation.

The Trust will reimburse the Corporation for Crown royalties and other Crown charges payable by the Corporation in respect of production from or ownership of the Properties. The Corporation will at all times be entitled to set off its right to be so reimbursed against its obligation to pay the NPI.

Pursuant to the Trust Indenture, all substantive amendments to the NPI Agreement must be approved by Special Resolution of the Unitholders.

In addition to the NPI, the Trust owns a beneficial interest in the Initial Direct Royalties and the Additional Direct Royalties and may acquire additional Direct Royalties in the future. These royalties consist of direct petroleum and natural gas royalty interests acquired by the Trust from time to time.

Deferred Purchase Price Obligation

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

- (a) the portion of Future Acquisition Costs incurred by the Corporation from time to time and after the date of the NPI Agreement which are attributable to Canadian resource property payable at the time of incurring such Future Acquisition Costs, plus
- (b) certain designated drilling, completion, equipping and other costs in respect of the Properties payable at the time of incurring such expenditures, plus
- (c) the portion of indebtedness incurred in respect of such Future Acquisition Costs and capital expenditures payable at the time of satisfaction by the Corporation of such indebtedness. To satisfy the Deferred Purchase Price Obligation, pursuant to the NPI Agreement, 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 or 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 NPI Income, and therefore will not reduce payments of NPI Income to the Trust or distributions to Unitholders;
- (b) the Trust will be obliged to pay to the Corporation ninety-nine (99%) percent 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 gas property expenditures account ("COGPE") of the Trust, thus creating additional tax deductions (see "Canadian Federal Income Tax Considerations"); and
- (d) the additional revenue generated from the additional Properties acquired by the designated expenditure will be added to the revenues used to calculate NPI Income thereby potentially increasing the amount payable to the Trust under the NPI Agreement.

Acquisitions

The Corporation may acquire additional Properties from time to time pursuant to the NPI Agreement and is entitled to fund such acquisitions from Residual Revenues, the Deferred Purchase Price Obligation, borrowings, or working capital of the Corporation.

Dispositions

Pursuant to the NPI Agreement, to the extent that Properties are disposed of by the Corporation, the Trust will be entitled to 99% of the net proceeds of disposition of the Canadian resource property component thereof after retiring any borrowing which relates to such component in consideration for the release of the NPI from such Properties. The Corporation will be entitled to reinvest such proceeds on behalf of the Trust pursuant to the Deferred Purchase Price Obligation.

The proceeds from the disposition by the Corporation of any of the Properties that are not attributable to Canadian resource properties will not be included in NPI Income. Management of the Corporation intends to use such proceeds, together with the residual 1% of the net proceeds received by the Corporation from sales of the Canadian resource property components of the Properties, to defray certain costs and expenses and capital expenditures of the Corporation as described above or to purchase additional Properties which will be subject to the NPI.

In connection with the sale of any interests in the Direct Royalties in accordance with the Administration Agreement, the Corporation will determine whether the net proceeds of the sale should be distributed to Unitholders or reinvested in additional Properties including additional Direct Royalties.

Farmouts

Pursuant to the NPI Agreement, the Corporation is permitted to Farmout any of the Properties if the farmee agrees to incur and pay capital expenditures for purposes of exploiting such Properties and in consideration thereof earns an interest in such Properties. Any such Farmout shall also be a Farmout of the NPI on the same terms such that that portion of the Properties, which has been farmed out, shall terminate.

Alberta Royalty Tax Credits

The Trust will be entitled to claim ARTC in respect of amounts reimbursed by it to the Corporation for Alberta Crown Royalties and other Alberta Crown charges in respect of Properties owned by the Corporation provided that the Properties (or any portion thereof) are not considered "restricted resource properties" within the meaning of the *Alberta Corporate Tax Act*.

All of the Initial Properties and Additional Properties are considered "restricted resource properties" and are not eligible for ATRC. However, the Trust will be entitled to claim ARTC in respect of amounts reimbursed by it to the Corporation for Alberta Crown royalties and other Alberta Crown charges in respect of the production from new wells drilled on the Initial Properties and the Additional Properties and from additional Properties acquired by the Corporation which are not "restricted resource properties" up to a maximum of \$2,000,000 of allowable Crown royalties and other charges. See "Canadian Federal Income Tax Considerations – Entitlement to Alberta Royalty Credits".

Non-Deductible Crown Royalties

Pursuant to the NPI Agreement, the Trust is required to reimburse the Corporation for 99% of all Non-Deductible Crown Royalties paid by the Corporation in respect of the Properties and the Corporation is entitled to set-off such amounts against payments otherwise required to be made to the Trust.

Reserve Fund

Under the NPI Agreement, the Corporation is entitled to pay such amounts of the revenues received from Production and any Residual Revenues 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 credited to NPI Deductions in calculating NPI Income.

Reclamation Fund

The Corporation will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the Properties upon abandonment. In connection with the acquisition of the Initial Properties and the potential acquisition of the Additional Properties, the Corporation hired engineering consultants and conducted an environmental assessment to estimate reclamation and abandonment liabilities for all wells and facilities associated with the Properties. The Corporation's staff also conducted field visits on all major properties and reviewed every major battery, as well as all natural gas processing and compressor facilities. Well abandonment and reclamation costs were determined taking into account the well type, depth, zone, and topographical considerations. Surface facilities were reviewed for soil and groundwater contamination problems. Government records and the records of the applicable Vendor were reviewed to determine whether or not there were any extraordinary environmental concerns. Cost estimates were determined based upon average actual historical costs for similar projects.

Ongoing environmental obligations are expected to be funded out of cash flow. Those obligations will reduce the amount of NPI Income that is payable to the Trust. The Corporation currently estimates that the future environmental and reclamation obligations, after salvage recovery costs, in respect of the Initial Properties and the Additional Properties will aggregate approximately \$4.3 million and \$5.4 million, respectively, over the life of the Initial Properties and the Additional Properties as the case may be.

Pursuant to the NPI Agreement, the Corporation is required to establish a reclamation fund to which it makes annual contributions, commencing in 2002 which will provide for the ultimate site restoration and well and facility abandonment expenditures on an appropriate basis over the Economic Life of the relevant reserves. Contributions to the Reclamation Fund may be adjusted by the Corporation from time to time based on its assessment of its share of expected environmental and final site reclamation costs. Contributions made by the Corporation to the Reclamation Fund may not be currently deductible for income tax purposes and may therefore reduce Cash Available For Distribution without an offsetting tax deduction. To the extent that funds are drawn from the Reclamation Fund and used for site restoration and well and facility abandonment expenditures such amounts will be credited to NPI Deductions in calculating NPI Income.

In addition to the identified producing wells and wells capable of production, the Initial Properties include interests in 43 gross (42 net) active injection, disposal or service wells and 52 gross (51 net) suspended or shut-in wells and the Additional Properties include interests in 17 gross (10 net) active injection, disposal or service wells and 48 gross (38 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. **The estimates of reserves associated with the Initial Properties and the Additional**

Properties and the present worth of future net cash flows from such reserves contained in the McDaniel Report are stated before providing for estimated facility site restoration, well abandonment and well site restoration costs.

Insurance

The Corporation carries insurance policies to provide protection for its working interest in the Properties at or above industry standards. Insurance policies cover property damage, general liability and, for certain properties, business interruption. The ongoing level, type and maintenance of insurance will be determined by the Corporation based upon the availability and cost of such insurance and the Corporation's perception of the risk of loss. The cost of insurance reduces the amount of NPI Income payable to the Trust. See "Risk Factors – Environmental Concerns".

Cash Available For Distribution

Cash Available For Distribution will consist 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 Corporation, dividends on the shares of the Corporation or any other dividends on securities of the Corporation less all expenses and liabilities of the Trust, including Debt Service Charges, which are due or accrued and which are chargeable to income shall be deducted in computing the Cash Available For Distribution.

Pursuant to the Trust Indenture and the Administration Agreement, the Corporation will calculate the NPI Income for each calendar month and will arrange for payment of certain direct expenses of the Trust from the NPI.

The actual amount of Cash Available For Distribution will depend on, among other things, the quantity of crude oil, natural gas and natural gas liquids produced, prices received for such production, direct expenses of the Trust, taxes, operating costs, Capital Expenditures, Debt Service Charges, Crown and other royalties, other Crown charges, net contributions to the Corporation's Reclamation Fund and Reserve Fund and General and Administrative costs of the Trust and the Corporation. See "Risk Factors".

The Corporation will 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 Corporation 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 intends to retain 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.

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 will be distributed to Unitholders.

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.

Income Tax Treatment

Any amounts paid by the Trust in respect of Future Acquisition Costs and the Deferred Purchase Price Obligation will be Canadian oil and gas property expense ("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 Cash Available To Be Distributed 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 4 individuals. Pursuant to the Trust Indenture, Unitholders will be entitled to cause the election of the Board of Directors. The Corporation will have an annual meeting each year, commencing in 2003. 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".

Decision Making

Under the NPI Agreement, the Corporation has the exclusive control and authority over development of, and recovery of petroleum substances 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) establishment of credit facilities will be made by the Board of Directors.

The Board of Directors intends to hold regularly scheduled meetings to review the business and affairs of the Corporation and the Trust and make any necessary decisions relating thereto.

Management of the Trust

Pursuant to the Trust Indenture and the Administration Agreement, the Corporation is required, among other things, to:

- (a) administer and manage the day-to-day operations of the Trust, to act as agent for the Trust, to execute documents on behalf of the Trust and to make executive decisions which conform to general policies and general principles set forth in the Trust Indenture;
- (b) keep and maintain at its offices in Calgary, Alberta at all times books, records and accounts relating to the Trust Fund and prepare all returns, filings and documents and make all determinations necessary for the discharge of the Trustee's obligations under the Trust Indenture;
- (c) monitor the tax status of the Trust and provide information to the Trustee regarding the taxable portions of distributions and submit all income tax returns and filings to the Trustee so that the Trustee has a reasonable opportunity to review them, approve them, execute them and return them and arrange for their filing within the time required by applicable tax law;
- (d) provide advice with respect to the Trust's obligations as a reporting issuer and ensure compliance by the Trust with continuous disclosure obligations under applicable securities legislation including the preparation and filing of reports and other documents with all applicable regulatory authorities;
- (e) provide investor relations services to the Trust including assisting with communications with Unitholders;

- (f) at the request and under the direction of the Trustee, call and hold all annual and/or special meetings of the Unitholders pursuant to the Trust Indenture, prepare all materials (including notices of meetings and information circulars) in respect thereof and submit all such materials to the Trustee in sufficient time prior to the dates upon which they must be mailed, filed or otherwise relied upon so that the Trustee has a reasonable opportunity to review them, approve them, execute them and return them to the Corporation for filing or mailing or otherwise;
- (g) provide office space, equipment and personnel including all accounting, clerical, secretarial, corporate and administrative services as may be reasonably necessary to perform its obligations under the Administration Agreement;
- (h) provide or cause to be provided such audit, accounting, engineering, legal, insurance and other professional services as are reasonably required or desirable for the purposes of the Trust including, without limitation, administration of the Direct Royalties, from time to time and provide or cause to be provided such legal, engineering, financial and other advice and analysis as the Trustee may require or desire to permit it to make informed decisions in connection with the discharge by it of its responsibilities as Trustee, to the extent such advice and analysis can be reasonably provided or arranged by the Corporation;
- (i) provide assistance in negotiating the terms of any financing required by the Trust or otherwise in connection with the Trust Fund;
- (j) take all actions reasonably necessary in connection with, or in relation to, the banking activities of the Trustee, the redemption of Trust Units pursuant to the Trust Indenture and the voting rights on any investments in the Trust Fund or any Subsequent Investments;
- (k) take all actions reasonably necessary in connection with, or in relation to, directly or indirectly, the borrowing of money from or incurring indebtedness by the Trust to any person and in connection therewith, to cause the Trust 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 (as defined in the *Securities Act* (Alberta) 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;
- (l) take all actions reasonably necessary in connection with, or in relation to, the guarantee by the Trust of obligations of the Corporation or any other affiliate of the Trust pursuant to any debt for borrowed money or obligations resulting or arising from hedging instruments incurred by the Corporation or any such affiliate, as the case may be, and pledging securities issued by the Corporation or the affiliate, as the case may be, as security for such guarantee provided that such guarantee is incidental to the Trust's direct or indirect investment in the Corporation or any such affiliate or the business and affairs (existing or proposed) of the Corporation or any such affiliate, and each such guarantee entered into by the Trustee shall be binding upon, and enforceable in accordance with its terms against, the Trust;
- (m) take all actions reasonably necessary in connection with, or in relation to, the Trust providing indemnities for the directors and officers of the Corporation and any affiliates;
- (n) provide or cause to be provided to the Trustee any services reasonably necessary for the Trustee to be able to consider any future acquisitions or divestitures by the Trustee of any portion of the Trust Fund;
- (o) provide advice to the Trustee with respect to determining the timing and terms of future offerings of Units, if any;
- (p) administer all of the records and documents relating to the Trust Fund other than maintenance of a register of Unitholders;
- (q) provide advice and, at the request and under the direction of the Trustee, direction to the transfer agent of the Trust;
- (r) provide advice and assistance to the Trustee with respect to the performance of the obligations of the Trust and the enforcement of the rights of the Trust under all agreements entered into by the Trust;

- (s) monitor the status of the Units as eligible investments for registered retirement savings plans, registered retirement income funds, and deferred profit sharing plans (all within the meaning of the Tax Act) and immediately provide the Trustee with written notice when the Corporation reasonably foresees that such Units may cease to have such status, or, if not reasonably foreseen, when the Units cease to have such status;
- (t) provide such additional administrative and support services pertaining to the Trust, the Trust Fund and the Units and matters incidental thereto as may be reasonably requested by the Trustee from time to time;
- (u) administer all matters relating to the Direct Royalties and the Trust, including: (i) determining the total amounts owing to Unitholders and arranging for cash distributions of Cash Available For Distribution; (ii) providing Unitholders with periodic reports on the NPI, the Direct Royalties and the Properties; and (iii) providing Unitholders with financial reports and tax information relating to the Properties, the NPI and the Direct Royalties;
- (v) in the event that withholding taxes are exigible on any distributions or redemption amounts distributed under the Trust Indenture or any other agreement, the Corporation shall withhold the withholding taxes required and shall promptly remit such taxes to the appropriate taxing authority. In the event that withholding taxes are exigible on any distributions or redemption amounts distributed under the Trust Indenture or any other agreement and the Corporation is, or was, unable to withhold taxes from a particular distribution to a Unitholder or has not otherwise withheld taxes on past distributions to a Unitholder, the Corporation shall be permitted to withhold amounts from other distributions to satisfy the Corporation's withholding tax obligations;
- (w) provide management services for the economic and efficient exploitation of the Properties and the Direct Royalties; and
- (x) recommend, carry out and monitor property acquisitions and dispositions and exploitation and development programs for the Trust.

In exercising its powers and discharging its duties under the Administration Agreement, the Corporation shall 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 shall be 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 objective, the Corporation will employ prudent oil and natural gas business practices. All of the Corporation's business will be conducted in accordance with applicable laws with a view to the best interests of the Unitholders and the Trust.

The Harvest Board will review on an ongoing basis both the nature and extent of the services required of the Corporation to the Trust and the costs of providing the same.

General and Administrative Costs are deducted from production revenues in computing NPI Income 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 will generally be 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 Initial Properties Vendors and the Additional Properties Vendor to the Corporation of ownership, management and operatorship of the Initial Properties and the Additional Properties. To the extent that such costs have been incurred to date, they have been paid by the Corporation by drawdowns under a prior credit facility and the Interim Loan.

Trust Debenture

The Trust Debenture was issued on August 15, 2002 by the Trust in exchange for \$5,000,000 in cash. The Trust Debenture bears interest at 2.25%, is unsecured and is due December 31, 2002. Principal and outstanding interest under the Trust Debenture will be settled in either cash or Trust Units, at the option of the holder. If settled in Trust Units, the dollar amount outstanding will be converted to Trust Units at a fixed price of \$1 per Trust Unit. Outstanding amounts due under the Trust Debenture become due and payable on the earlier of December 31, 2002 and the date on which the Trust qualifies as a mutual fund trust through the listing of the Trust Units on a recognized Canadian stock exchange. It is anticipated that upon Closing, the Trust will so qualify, and that the holder of the Trust Debenture will elect to receive 5,000,000 Trust Units in settlement of the Trust Debenture.

It is anticipated that the holder of the Trust Debenture will settle the Management Group Debentures with the 5,000,000 Trust Units it elects to receive from the Trust on settlement of the Trust Debenture. The Management Group holds the Management Group Debentures. **The issuance of Trust Units to the Management Group pursuant to settlement of the Trust Debenture and the Management Group Debentures will result in dilution to the purchasers of Trust Units pursuant to the Offering.** See "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".

As a condition to completion of the Offering, certain members of the Management Group holding an aggregate \$4,042,500 principal amount of the Management Group Debentures have agreed to execute 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 currently held by such holder or such holder's spouse, directly or indirectly, at any time until the date two years following the date of issue of a final receipt for this prospectus. See "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".

Interim Loan

The Trust has entered into two loan agreements dated July 10, 2002 and July 30, 2002, with Caribou. The first interim loan agreement provides for up to \$13 million of debt to the Trust, and the second interim loan agreement provides for up to \$30 million of debt. Each loan agreement making up the Interim Loan includes the following terms: (a) interest is payable at 20% per annum on the outstanding balance; and (b) the loans mature on July 31, 2003 and are secured by all of the assets of the Trust, including the NPI, but are not secured against the Properties of the Corporation.

Under the terms of the loan agreement dated July 30, 2002, the Trust has committed to pay a fee to Caribou of 150,000 Warrants to purchase an equivalent number of Trust Units for \$1.00 each. See "Description of the Trust – Warrants". The interest payable under this loan agreement may be received in cash or Trust Units, at the election of Caribou. Trust Units would be issued based on the most recent five-day weighted average trading price of the Trust Units on the TSX.

Upon closing of the Additional Properties Acquisition, the Trust had borrowed \$23.2 million under the Interim Loan. The Interim Loan bears interest at 20% per annum and was provided by Caribou, which is controlled by M. Bruce Chernoff, a director of the Corporation. The loan is secured by all of the assets of the Trust, including the NPI, but is not secured by the Properties of the Corporation. The Trust paid these amounts to the Corporation to purchase the NPI and the Initial Direct Royalties from the Corporation and to finance the Deferred Purchase Price Obligation in respect of the Additional Properties Acquisition. See "Acquisition of the NPI", "Initial Properties" and "Additional Properties". The Corporation used these amounts to partially finance the acquisitions of the Initial Properties and the Additional Properties. The Trust will use approximately \$23.4 million from the net proceeds of the Offering to repay the Interim Loan (including accrued interest) and approximately \$4.2 million from the net proceeds of the Offering to partially repay the advance made under the Current Bank Facility which was used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan", "Capitalization of the Trust" and "Use of Proceeds".

Warrants

Pursuant to the Interim Loan, Caribou has been granted 150,000 Warrants by the Trust to purchase an equivalent number of Trust Units at \$1.00 each. The Warrants are exercisable upon completion of the Offering and will expire on July 31, 2003. The Warrants were issued as a commitment fee pursuant to the Interim Loan. See "Interim Loan". M. Bruce Chernoff, a director of the Corporation, controls Caribou. **The issuance of Trust Units to Caribou pursuant to the exercise of the Warrants will result in dilution to the purchasers of Trust Units pursuant to the Offering.** See "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".

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.". The head and principal office of the Corporation is located at Suite 2400, 500 - 4th Avenue S.W., Calgary, Alberta, T2P 2V6 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, a wholly-owned subsidiary of the Trust, was incorporated on May 14, 2002 to carry on oil and natural gas acquisition, development and production activities. See "Background to the Offering", "Acquisition of NPI", "Initial Properties" and "Additional Properties".

Pursuant to the Trust Indenture and the Administration Agreement, the Corporation manages and administers 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, and the Corporation has a staff of 21 people 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 substances.

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 operating expense reduction;
- (c) identifying upside opportunities in acquired Properties;
- (d) acquiring other assets within existing operating areas to achieve operating and development efficiencies;
- (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:

- maximizing 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 existing Properties and acquiring additional Properties.

Acquisition Strategy:

In order to grow the asset base of the Corporation and offset natural production declines from existing Properties, the Corporation may acquire producing properties and/or participate in development activities that are considered to be of a low risk nature in the oil and natural gas industry. The Corporation may also from time to time present proposals for the acquisition by the Trust of additional Direct Royalties. The Corporation's acquisition strategy will target individual properties, or groups of properties, that generally comply with the following guidelines which have been established by the Harvest Board:

- each acquisition of a property, or group of properties, for a purchase price in excess of \$5 million, will be based on engineering in an independent engineering report, unless specifically approved by the Board of Directors, which may be modified to incorporate the Corporation's views of the engineering analysis contained in the report;
- mature producing properties that are in geographic proximity to the Properties or other properties which management of the Corporation considers that it has particular expertise to effectively extract value potential; and
- not more than 25% of the total Reserve Value of a property, or group of properties, will be attributable to a single well.

The Corporation may introduce its own technical views and may modify the independent engineering evaluation associated with Properties being acquired. The Corporation may also take into consideration the continuation of current field development activities being pursued beyond the operator's existing plans, reflecting identified opportunities for further drilling, production enhancements and lower operating costs through field and facility optimization. The Corporation may also incorporate modest fixed operating cost reductions once production from individual properties falls below a certain level to reflect expected facility rationalization.

The Corporation may acquire properties with a relatively low reserve life if the Board of Directors believes, after evaluating development and optimization opportunities associated with such properties, that the future net cash flows adequately justify the initial purchase price plus planned incremental capital investments.

These criteria will serve as guidelines for the Corporation management in presenting acquisitions for approval by the Harvest Board. The Board of Directors may vary these criteria for any particular acquisition based on management's recommendations and consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.

Operating Strategy:

A primary objective of the Corporation is the maximization of operating cash flows, oil and natural gas production and reserves recovery from the Properties. This objective will be accomplished through an intensive oil and natural gas field management program. The senior management of the Corporation possess extensive experience in the operation of mature oil and natural gas fields. A key feature of the Corporation's structure and management is the operatorship of the majority of the Properties.

The field management of an oil and natural gas property is delegated by the working interest owners to an operator, usually the largest working or unit interest percentage participant. The operator of a property generally originates the plans and makes the decisions regarding the development and operation of the property, including the level and timing of capital expenditures. Accordingly, the Corporation believes that it is advantageous for it to become operator wherever possible. The Initial Properties Vendors and the Additional Properties Vendor operated 100% of the production from the Initial Properties and the Additional Properties and the Corporation has replaced the Initial Properties Vendors and the Additional Properties Vendor as the successor operator of each of the Initial Properties and the Additional Properties. In evaluating acquisitions of additional Properties, the Corporation will attempt to purchase Properties where it can assume operatorship.

The Corporation believes that operatorship will generally result in the following advantages for Unitholders:

- the operator's control of operations provides opportunities to enhance production from the Properties and to positively influence netbacks through operating cost controls and marketing arrangements;
- the operator is in the best position to control the scope and timing of development activities and capital expenditures to initiate production from Proved Non-Producing Reserves, Probable Reserves and Undeveloped Lands;
- operatorship provides opportunities to enhance the value of the Properties through the application of local operating and technical knowledge and the application of new technologies;
- control of operations facilitates the management of risks associated with the Properties. The operator is directly in charge of environmental and safety loss prevention programs;

- the operator receives direct payment from the purchaser of Petroleum Substances produced from a Property without delays in cash flows that might otherwise occur; and
- the operator will acquire information and greater technical understanding about an area that may be used to pursue the development or acquisition of properties in the area or properties in adjacent areas.

Oil and Natural Gas Field Exploitation Strategy:

A key tactic in optimizing the value extraction from the Properties will be an active program of oil and natural gas field exploitation. In addition to their extensive operating experience, the Corporation's senior management team have a broad base of experience in the development and exploitation of mature oil and natural gas assets.

Field exploitation of the Initial Properties and the Additional Properties by management is anticipated to result in the following advantages for Unitholders:

- typical development and exploitation activities require relatively low amounts of capital and can provide an attractive annualized rate of return;
- incremental production can often be processed through existing facilities at only the variable operating cost rates. This may improve the net cash received from new production and can assist in defraying fixed costs for existing production;
- optimization of production transportation systems and production processing facilities may increase production levels and reduce operating costs, thereby increasing ultimate reserve recovery;
- amortizing the fixed costs of existing operations over the incremental production being developed can significantly extend the economic life of existing wells and thereby enhance reserve recovery; and
- rigorous geological and technical analysis of oil and natural gas reserves that cannot be produced from existing wells may reveal pockets of incremental reserves. Low risk development drilling typically provides low cost production and reserve additions that extend the economic life of an oil and natural gas field. See "Description of Initial Properties – Incremental Exploitation and Development Potential" and "Description of Additional Properties – Incremental Exploitation and Development Potential".

Risk Management Strategy:

The Corporation intends to employ the following strategies to manage risk:

- commodity price risk will be managed with a hedging program utilizing swaps, collars and options. See "Information Respecting the Corporation – Commodity Hedging". Any contracts will be entered into with large, stable counter parties and, to the extent possible, the Corporation will avoid concentrating significant risk with any one counter party;
- production volume risk will be managed through a program of preventative ongoing well and facility maintenance, property and business interruption insurance, as long as the cost of such insurance is economically justifiable, and minimizing production concentration to the extent possible;
- reserve risk will be attempted to be minimized by acquiring additional Properties in mature, stable pools, with a history of predictable production levels;
- environmental, health and safety risk will be addressed through a facility and well maintenance program as described above along with strict adherence to applicable regulations and best industry practice; and
- financial risk will be minimized through cost control, maximizing efficiency of operations and prudently managing debt levels.

Subsequent Acquisitions

The Corporation may acquire Properties and fund such acquisitions from production revenues, the proceeds of the Deferred Purchase Price Obligation (which will be financed by the Trust issuing additional Trust Units or from the proceeds of disposition of the NPI in respect of Properties which are disposed of, the proceeds of disposition of Direct Royalties or borrowings), borrowings, Farmouts or with working capital of the Corporation. See "Information Respecting the Corporation – Capital Expenditures".

Dispositions

The Corporation may sell any of its interests in Properties and the Trust may release the NPI therefrom if the Corporation and the Trust determine that such sale and release would be in the best interests of the Unitholders. The Trust may sell any of its interests in the Direct Royalties if it determines that such sale would be in the best interests of the Unitholders. The Trust Indenture and the NPI Agreement permit the Trust and the Corporation to effect such sales and releases provided that the sale is approved by a Special Resolution of the Unitholders in the event the interests in the Properties being sold constitute all or substantially all of the Properties unless the sale is to an Affiliate of the Corporation and provided such sale is approved by the Harvest Board for sales of Properties for proceeds in excess of \$5 million. See "Description of the Trust – Decision Making". The proceeds of a disposition of an interest in the Properties owned by the Corporation to the extent related to Canadian resource properties will be allocated 99% to the Trust after retiring any borrowing which relates to the Canadian resource property component of such interest in consideration for the release of the NPI from such Properties. The proceeds of disposition of interests in the Properties owned by the Corporation that are not attributable to interests in Canadian resource properties will be used to defray certain costs and expenses and capital expenditures of the Corporation or to purchase additional Properties which will be subject to the NPI. The Trust will receive all of the proceeds of disposition of interests in Direct Royalties.

In connection with the sale of any such interests in the Properties, the Corporation will determine whether the net proceeds of the sale should be reinvested on behalf of the Trust pursuant to the Deferred Purchase Price Obligation. Otherwise such proceeds will be paid to the Trust and form part of the Cash Available For Distribution which will be distributed to Unitholders unless retained by the Trust in the Capital Fund.

Capital Expenditures

The Corporation may approve future capital expenditures or Farmouts under the terms of the NPI Agreement. Future capital expenditures on the Properties will generally be of the type which are intended to maintain or improve production from the Properties. The Corporation may finance capital expenditures from production revenues, the proceeds of the Deferred Purchase Price Obligation (which will be financed by the Trust issuing additional Trust Units, from the proceeds of disposition of the NPI in respect of Properties which are disposed of by the Corporation, from proceeds of disposition of Direct Royalties or from borrowings by the Trust), by drawing amounts from the Capital Fund, borrowings, Farmouts or with working capital of the Corporation. **Capital expenditures, which are funded from production revenues, may have a negative short-term effect on the Trust's cash flow and Cash Available For Distribution.** The Corporation will not ordinarily initiate any exploratory drilling or participate in exploratory drilling initiated by the operator of a property but may do so where, in the opinion of the Corporation, to do so would be in the best interests of the Trust.

Although the current Direct Royalties are not subject to capital spending obligations as those are the responsibility of the lessee and the operator under each lease, the Trust may invest capital to acquire additional Direct Royalties. Pursuant to the Trust Indenture, all such acquisitions will be made by the Corporation, on behalf of the Trust.

The Trust intends to implement a distribution strategy whereby it will retain as much as 50% of Cash Available For Distribution in a particular year in the Capital Fund, to finance future acquisitions and development of the Properties. See "Description of the Trust – Capital Fund". Management of the Corporation believes this will assist in maintaining distributions for a longer period than would otherwise be the case if all Cash Available For Distribution was immediately distributed to the Unitholders. See "Risk Factors".

Borrowing

The Corporation and the Trust are permitted to incur indebtedness to finance the purchase of Properties, capital expenditures or other financial obligations or expenditures in respect of the Properties or for working capital purposes. Indebtedness of the Corporation 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 Corporation: (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 Charges 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 NPI Income and income from Direct Royalties for such 12 month period, unless specifically approved by the Board of Directors. The Corporation will be entitled to grant security in priority to the NPI and the Trust will be 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 Corporation. All borrowings of the Trust require approval by the Board of Directors.

Debt Service Charges of the Corporation will be deducted in computing NPI Income and Debt Service Charges of the Trust will be deducted in computing Cash Available For Distribution. Debt repayment by the Corporation will be scheduled to minimize, to the extent possible, any income tax payable by the Corporation.

The Corporation has negotiated the Current Bank Facility with the Current Lender for US\$60 million for the purpose of funding general operating requirements and the acquisition of oil and natural gas properties. The initial borrowing base under the Current Bank Facility is US \$38 million. The outstanding principal amount of the Current Bank Facility is to bear interest at rates which vary depending upon the outstanding principal amount of the Current Bank Facility in relation to the then current borrowing base and the type of advance drawn. For direct advances, the interest rate is based on the Current Lender's prime rate (for U.S. dollar advances) and a money rate service screen rate plus .5% (for Canadian dollar advances) (the "CDOR Rate") plus a margin of 1.125% per annum or 1.875% per annum. For Eurodollar loans and advances by way of bankers' acceptances, the interest rate is based on the rates offer to specified banks in the London interbank market (for Eurodollar loans) or the discount rates applicable to each lender (being its own rate if it is a lender which accepts bankers' acceptances or the CDOR Rate for others) plus in each case a margin of 2.125% per annum or 2.875% per annum. In either case, the higher margin is applied when amounts outstanding under the Current Bank Facility exceed 75% of the borrowing base. The Current Bank Facility is secured by a first floating charge over all of the Corporation's assets and a fixed charge over specified oil and gas reserves. The Current Bank Facility revolves until April 30, 2004 at which time it is due and payable in full. Dividends and other distributions by the Corporation are prohibited during a default, event of default or an unremedied borrowing base shortfall 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 specifically subordinate to the Current Bank Facility pursuant to a subordination agreement between the Current Lender, the Trustee and the Corporation dated November 14, 2002. This 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 limit the Cash Available For Distribution during a default, event of default or an unremedied borrowing base shortfall under the Current Bank Facility.

The Corporation must meet certain minimum commodity price hedging levels and ongoing financial covenants under the Current Bank Facility and is subject to customary restrictions on its operations and activities, including restrictions on incurring indebtedness, granting of security, the issuance of incremental debt and the sale of its assets. During such time as any lender comprising the Current Lender is not a Canadian resident, payments under the Current Bank Facility to such lender will be subject to certain withholding taxes which the Corporation has agreed to assume and which may increase the effective interest rate paid by the Corporation.

The Corporation's indebtedness under the Current Bank Facility is approximately \$56.7 million, of which approximately \$12.3 million was used to repay all outstanding indebtedness under the prior credit facility, approximately \$38.6 million was used to partially fund the Additional Properties Acquisition, approximately \$2.3 million was paid in respect of fees and expenses to establish the Current Bank Facility, with approximately \$2.3 million committed to cover current expenditures and \$1.2 million committed to collateralize outstanding letters of credit. The Corporation has pledged cash collateral for the issuance of approximately \$1.2 million of letters of credit to third parties, on behalf of the Corporation, to secure utility services on the Properties. See "Initial Properties" and "Use of Proceeds".

Commodity Hedging

The Corporation has entered into the following oil price financial hedging contracts with various counterparties, including the Corporation's prior lender:

Swaps:

1,200 Bbls/d	September through December 2002	Cdn \$39.31
1,000 Bbls/d	January through March 2003	Cdn \$38.30
1,000 Bbls/d	April through June 2003	Cdn \$37.59
1,000 Bbls/d	July through September 2003	Cdn \$37.10
1,000 Bbls/d	October through December 2003	Cdn \$36.63
200 Bbls/d	January through March 2003	U.S. \$24.95
200 Bbls/d	April through June 2003	U.S. \$24.39
1,510 Bbls/d	January through March 2004	U.S. \$23.23
1,430 Bbls/d	April through June 2004	U.S. \$22.93
1,380 Bbls/d	July through September 2004	U.S. \$22.70
1,325 Bbls/d	October through December 2004	U.S. \$22.54
1,100 Bbls/d	January through March 2005	U.S. \$22.38
1,030 Bbls/d	April through June 2005	U.S. \$22.18

Collars:

500 Bbls/d	September through December 2002	Cdn \$36.50 – 41.67
500 Bbls/d	January through March 2003	Cdn \$35.00 – 41.30
500 Bbls/d	April through June 2003	Cdn \$35.00 – 39.60
500 Bbls/d	July through September 2003	Cdn \$35.40 – 38.40
500 Bbls/d	October through December 2003	Cdn \$35.50 – 37.35

On closing the Additional Properties Acquisition, the Corporation entered into a physical contract to deliver 6,000 Bbls/d of Lloydminster blend crude oil to the Additional Properties Vendor at Hardisty, Alberta until December 31, 2003. This requires the Corporation to purchase approximately 1,000 Bbls/d of diluent to blend with its production to meet the oil quality requirements at the delivery point. Under the contract, the Corporation will be paid a price equal to the NYMEX calendar WTI price less a fixed differential of U.S. \$8.233 per Bbl, such price not to be less than U.S.\$14.40 per Bbl or greater than U.S.\$17.244 per Bbl. In effect, this contract applies a fixed differential to a WTI price collar between U.S. \$22.633 and U.S.\$25.477 per Bbl. This contract is effective until December 31, 2003. See "Additional Properties – Marketing Arrangements". In addition, pursuant to the Current Bank Facility, the Corporation is required to maintain commodity hedging agreements in effect from time to time with respect to not less than 66 2/3% of its production profile.

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	Principal Occupation
John A. Brussa ⁽¹⁾⁽³⁾⁽⁶⁾ Calgary, Alberta	Director	Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP (a law firm).

Name and Municipality of Residence	Position with the Corporation	Principal Occupation
M. Bruce Chernoff ⁽²⁾⁽³⁾⁽⁷⁾ Calgary, Alberta	Director, Chairman	Professional Engineer; Chairman and acting Chief Financial Officer 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.
Verne G. Johnson ⁽¹⁾⁽²⁾⁽⁸⁾ Calgary, Alberta	Director	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 ⁽¹⁾⁽³⁾⁽⁹⁾ Calgary, Alberta	Director	Independent businessman and Director of Hunting PLC (a UK based public oil and natural gas company); formerly, President, Midstream Division, Alberta Energy Company Ltd. (a public oil and natural gas company).
Jacob Roorda ⁽¹⁰⁾ Calgary, Alberta	President	Professional Engineer, President and Chief Executive Officer 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 (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 ⁽¹¹⁾ Calgary, Alberta	Vice President, Operations	Vice President, Operations of the Corporation; from 1996 to 2002, Manager, Production of Penn West (a public oil and natural gas company).
David M. Fisher ⁽¹²⁾ Calgary, Alberta	Vice President, Finance	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 (a private oil and natural gas corporation); from April 1995 to July 1998, Vice President, Finance and Chief Financial Officer of Canrise (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.

Name and Municipality of Residence	Position with the Corporation	Principal Occupation
David J. Rain ⁽¹³⁾ Calgary, Alberta	Corporate Secretary	Chartered Accountant; 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) Member of the Audit and Corporate Governance Committee.
- (2) Member of the Reserves, Safety and Environment Committee.
- (3) Member of the Compensation Committee.
- (4) The Corporation does not have an executive committee.
- (5) The terms of office of all of the directors will expire at the next annual shareholders' meeting of the Corporation.
- (6) Mr. Brussa beneficially owns \$165,000 principal amount of Management Group Debentures which may be settled in 165,000 Trust Units in accordance with the terms of the Management Group Debentures. See "Description of the Trust – Trust Debenture", "Interests of Management and Others in Material Transactions", "Capitalization of the Trust" and "Risk Factors – Dilution".
- (7) Mr. Chernoff and his spouse beneficially own \$3,400,000 principal amount of Management Group Debentures which may be settled in 3,400,000 Trust Units in accordance with the terms of the Management Group Debentures. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution". Pursuant to the Interim Loan, the Trust has also issued 150,000 Warrants to Caribou, a company controlled by Mr. Chernoff, to purchase an equivalent number of Trust Units for \$1.00 each. These Warrants are exercisable until July 31, 2003. See "Description of the Trust – Warrants".
- (8) Mr. Johnson and his spouse beneficially own \$10,000 principal amount of Management Group Debentures which may be settled in 10,000 Trust Units in accordance with the terms of the Management Group Debentures. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".
- (9) Mr. McFadyen and his spouse beneficially own \$10,000 principal amount of Management Group Debentures which may be settled in 10,000 Trust Units in accordance with the terms of the Management Group Debentures. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".
- (10) Mr. Roorda and his spouse beneficially own \$75,000 principal amount of Management Group Debentures which may be settled in 75,000 Trust Units in accordance with the terms of the Management Group Debentures. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".
- (11) Mr. Ralston and his spouse beneficially own \$75,000 principal amount of Management Group Debentures which may be settled in 75,000 Trust Units in accordance with the terms of the Management Group Debentures. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".
- (12) Mr. Fisher beneficially owns \$35,000 principal amount of Management Group Debentures which may be settled in 35,000 Trust Units in accordance with the terms of the Management Group Debentures. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".
- (13) Mr. Rain and his spouse beneficially own \$77,500 principal amount of Management Group Debentures which may be settled in 77,500 Trust Units in accordance with the terms of the Management Group Debentures. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".

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 Queens 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 Petroleum ("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. Penn West's production included approximately 9,000 Bbls/d of 16° heavy oil in Saskatchewan and Alberta.

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 employment included 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 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

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 carry out investments in oil and natural gas and real estate. 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. Mr. Chernoff is also a director of several other public companies.

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 joined the Enerplus Resources Group in 2000, becoming Senior Vice President of Funds Management. In February 2002, he left the Enerplus Resources Group and remains as President of his private family company, KristErin Resources Ltd.

Hector J. McFadyen, Director

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

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

Mr. McFadyen began work for Alberta Energy Company Ltd. ("AEC"), presently known as EnCana Corporation ("EnCana"), in 1976. EnCana is the largest independent oil and natural gas producer in North America. Mr. McFadyen assumed positions of increasing responsibility, serving as a Vice President since 1981, and retiring as of June 2002.

Mr. McFadyen developed a number of significant business units within AEC, developing experience in a broad range of businesses and disciplines, and which have 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 since 1981, 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, was recently appointed to the board of directors of Hunting PLC ("Hunting"), a UK-based public corporation engaged in oil and natural gas, oilfield service, and oil and natural gas marketing and distribution activities. Hunting carries on its oil and natural gas marketing and distribution activities through its majority owned subsidiary, Gibson Energy Ltd. See "Interests of Management and Others in Material Transactions".

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 articulated at KPMG LLP Chartered Accountants and left as a Manager in their audit group 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.

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 Corporation 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 10 years preceding the date of this prospectus, 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.

Other Reporting Issuer Experience

The following table sets out the directors and officers of the Corporation that are, or have been within the last five years, directors or officers of other reporting issuers, their position with such issuers and the period of their involvement with such issuers:

Name	Name of Reporting Issuer	Position	From	To
John Brussa	Allied Oil & Gas Corp.	Director	02 1998	11 2001
	Antrim Energy Inc.	Director	09 1999	10 2002
	Applied Terravision Systems Inc.	Director	03 2001	03 2002
	Ascot Energy Resources Ltd.	Director	11 1999	05 2002
	Aventura Energy Inc.	Director	09 1999	03 2002
	Barrington Petroleum Ltd.	Director	06 1996	09 1998
	Baytex Energy Ltd.	Director	08 1997	Present
	Brooklyn Energy Corporation	Director	11 2001	Present
	Campion Resources Ltd.	Director	05 2000	07 2002
	Chain Energy Ltd.	Director	11 2000	03 2002
	Collicutt Hanover Services Ltd.	Director	01 1999	Present
	Dorset Exploration Ltd.	Director	06 1990	09 1997
	Direct Energy	Director	10 1996	08 2000
	Edge Energy Inc.	Director	01 1998	08 2000
	Endev Energy Inc.	Director	01 2002	Present
	Focus Energy Ltd.	Director	08 2002	Present
	High Point Energy Corp.	Director	06 2002	Present
	IEI Energy Inc.	Director / Officer	03 2002	Present
	Imperial Metals Corporation	Director	06 1994	01 2002
	Interaction Resources Ltd.	Director	10 1997	05 2000
	Magin Energy Inc.	Director	06 1996	06 2001
	Meota Resources Corp.	Director	12 1997	10 2002
	Mill City International Inc.	Director	10 2002	Present
	NCE Energy Corporation	Director	11 1996	06 2002
	Penn West Petroleum Ltd.	Director	04 1995	Present
	Petrobank Energy and Resources Ltd.	Director	03 2000	Present

Name	Name of Reporting Issuer	Position	From	To
	Progress Energy Ltd.	Director	11 2000	Present
	Rio Alto Exploration Ltd.	Director	06 1992	07 2002
	Rio Alto International Inc.	Director	07 2002	Present
	Southpoint Resources Ltd.	Director	08 2002	Present
	Storm Energy Inc.	Director	10 1997	08 2002
	Storm Energy Ltd.	Director	08 2002	Present
	Tanganyika Oil Company Ltd.	Director	06 1997	09 2001
	Navigo Energy Inc. (formerly Ventus Energy Ltd.)	Director	08 1998	Present
	Westpoint Energy Inc. (formerly Slade Energy Inc.)	Director	01 1998	05 2000
M. Bruce Chernoff	Brooklyn Energy Inc.	Director	11 2001	Present
	Canadian Talon	Director	05 1997	05 1999
	International Datashare Corp.	Director	01 2000	Present
	Navigo Energy Inc.	Director	12 1996	Present
	Petrobank Energy & Resources Ltd.	Director	03 2000	Present
	Edge Energy Inc.	Director	12 1997	08 2000
	Pacalta Resources Ltd.	Director and Senior Officer	1988	05 1999
Verne Johnson	Alta Quest Energy Corporation	Director & President	04 1998	12 1999
	Blue Mountain Energy Ltd.	Director	05 2002	Present
	Elan Energy Inc.	Director & President	12 1989	09 1997
	Fort Chicago Energy Management Ltd.	Director	10 1997	Present
	Southward Energy Ltd.	Director	12 1997	Present
Hector McFadyen	Alberta Energy Company Ltd.	Senior Officer	09 1981	04 2002
	AEC Pipelines, L.P.	Senior Officer / Director	04 1997	09 2000
	Hunting PLC	Director	09 2002	Present
David Rain	International Datashare Corporation	Director	11 2000	Present
	Pacalta Resources Ltd.	Treasurer / Corp. Controller	05 1997	05 1999
	Petrobank Energy & Resources Ltd.	V.P. Finance & CFO	10 2001	Present
	Petrobank Energy & Resources Ltd.	Director, Corp. Finance	04 2000	09 2001
	Trican Well Service Ltd.	CFO	10 1996	05 1997
Jacob Roorda	Prime West Energy Inc.	Vice President & Director	10 1996	04 1999
David Fisher	Canrise Resources Ltd.	V.P. Finance & CFO	04 1995	07 1998

Remuneration of Directors and Officers

The directors of the Corporation may receive cash compensation for acting as directors of the Corporation and will be entitled to reimbursement for expenses incurred in acting as directors. The directors are entitled to participate in the Trust's Unit Incentive Plan. See "Trust Unit Incentive Plan".

The Corporation currently has three executive officers who receive annual salaries of \$125,000, \$100,000 and \$100,000, respectively. Such officers are eligible to receive non-transferable rights to purchase Trust Units in the future in accordance with the Trust's Unit Incentive Plan. See "Trust Unit Incentive Plan". The Corporation intends to enter into employment agreements with each of these two officers, and any additional senior officers, and such agreements are expected to contain industry standard severance and change of control provisions.

Capitalization

The following table sets forth the capitalization of the Corporation as at June 30, 2002, and as at such date after giving effect to the Current Bank Facility, the acquisition of the Initial Properties, the Additional Properties Acquisition and the Offering.

Designation	Authorized	Outstanding as at June 30, 2002	Outstanding as at June 30, 2002 after giving effect to the Current Bank Facility, the Interim Loan, the acquisition of the Initial Properties and the Additional Properties Acquisition	Outstanding as at June 30, 2002 after giving effect to the Current Bank Facility, the Interim Loan, the acquisition of the Initial Properties, the Additional Properties Acquisition and the Offering
Current Bank Facility ⁽¹⁾⁽²⁾⁽³⁾	US\$60 million	\$Nil	\$56,500,000	\$52,300,000
NPI ⁽⁴⁾	N/A	\$Nil	\$22,200,000	\$22,200,000
Common Shares ⁽⁵⁾	unlimited	\$100 (one hundred shares)	\$100 (one hundred shares)	\$100 (one hundred shares)

Notes:

- (1) Effective June 30, 2002, the Corporation had a borrowing base credit facility with an initial borrowing base of \$18 million with a Canadian chartered bank. The Corporation had drawn \$12 million on this credit facility for purposes of closing the acquisition of the Initial Properties and to finance \$3.0 million of the non-refundable deposit under the Additional Properties Agreement. On November 15, 2002, this facility was repaid in full through an advance made under the Current Bank Facility. See "Initial Properties", "Additional Properties" and "Information Respecting the Corporation – Borrowing".
- (2) In connection with the Additional Properties Acquisition, the Corporation entered into the Current Bank Facility. The Corporation's current indebtedness under the Current Bank Facility is approximately \$56.7 million, of which approximately \$12.3 million was used to repay all outstanding indebtedness under a previous credit facility, approximately \$38.6 million was used to partially fund the Additional Properties Acquisition, approximately \$2.3 million was paid in respect of fees and expenses to establish the Current Bank Facility, with approximately \$2.3 million committed to cover current expenditures and \$1.2 million committed to collateralize outstanding letters of credit. See "Initial Properties", "Additional Properties", "Information Respecting the Corporation – Borrowing" and "Use of Proceeds".
- (3) The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional \$5.7 million adjustment to the Additional Properties Acquisition Cost should be made in favour of the Additional Properties Vendor. This dispute relates to whether or not the value of a hedging contract held by the Additional Properties Vendor impacts the net proceeds from the Additional Properties from the effective date of the Additional Properties Acquisition of June 1, 2002 to the closing date of November 15, 2002. The Additional Properties Vendor has indicated its intent to charge the Corporation the additional \$5.7 million as an interim adjustment within 90 days of the closing of the Additional Properties Acquisition. Management of the Corporation believes that such amount is not owing to the Additional Property Vendor. This dispute is expected to be resolved through an arbitration process established in the Additional Properties Agreement. However, if this amount is not recoverable, the amount will be paid through an additional advance under the Current Bank Facility. See "Additional Properties" and "Risk Factors".
- (4) The NPI represents the obligations of the Corporation under the NPI Agreement to pay NPI Income to the Trust.
- (5) Held by the Trustee for and on behalf of the Trust.

Share Capital of the Corporation

The share capital of the Corporation consists of an unlimited number of common shares. As at the date hereof, only one hundred common shares 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 "The Trust Indenture – Exercise of Voting Rights Attached to Shares of the Corporation".

THE TRUST INDENTURE

The following is a summary only 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. Each Trust Unit shall entitle 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") and to one vote at all meetings of Unitholders for each Trust Unit held. See "Risk Factors – Nature of 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 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 which debentures, notes or other evidences of indebtedness may be created and issued 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 Charges incurred by the Trust will be 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 lawful money of Canada 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, provides representative fair market value price 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 to carry out such intentions. If at any time the Trust becomes aware that the beneficial owners of 49% or more of the Trust Units then outstanding 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" below), 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 – Management of the Trust". 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 or the NPI Agreement 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, willful 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 takeover 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 by the offeror.

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 money 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 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 shall be December 31. The Trust will be subject to the continuous disclosure obligations under all applicable securities legislation.

TRUST UNIT INCENTIVE PLAN

Subject to regulatory approval, the Trust has adopted a unit incentive plan (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.

The Harvest Board will administer the Unit Incentive Plan and determine 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 will be 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.

Subject to applicable regulatory approval, the Trust has reserved Trust Units equal to 10% of the number of Trust Units outstanding following the Closing for issuance under the Unit Incentive Plan. The number of Trust Units reserved for issuance under the Unit Incentive Plan may only be increased with Unitholders' approval and any necessary regulatory approval. The Unit Incentive Plan contains provisions for adjustments to the number of Trust Units issuable thereunder and the Exercise Price of the Incentive Rights in the event of a subdivision, consolidation, re-division or change to the Trust Units. The Unit Incentive Plan further provides for accelerated vesting of Incentive Rights if there is a change of control of the Trust or the Corporation (including a sale of assets representing at least 75% of the Corporation's total assets and the termination of the Trust).

At or upon Closing, the Trust intends to have issued Incentive Rights to purchase up to an aggregate of 750,000 Trust Units at the Offering Price per Trust Unit, expiring five years from the date of issuance, to various employees, officers, certain directors of or consultants to the Corporation.

DRIP PLAN

The Trust has authorized a Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP Plan") which will be implemented upon receipt of applicable regulatory approvals. **The DRIP Plan will not be 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 the Distributable Cash received by them. At the discretion of the Corporation, Trust Units will either be acquired at prevailing market rates or issued from treasury at 95% of the market price of the Trust Units. The issue of new Trust Units from treasury under the DRIP Plan will not be available until applicable regulatory approvals have been obtained. Subject to receipt of applicable regulatory approvals, participants in the DRIP Plan will also be

permitted to purchase additional Trust Units at the market price by investing additional sums within the limits established under the DRIP Plan.

CAPITALIZATION OF THE TRUST

The following table sets forth the consolidated capitalization of the Trust as at July 10, 2002, and as at such date after giving effect to the Current Bank Facility, the acquisition of the Initial Properties, the Additional Properties Acquisition and this Offering:

Designation	Authorized	Outstanding as at July 10, 2002	Outstanding as at July 10, 2002 after giving effect to the Current Bank Facility, the Acquisition of the Initial Properties and the Additional Properties Acquisition	Outstanding as at July 10, 2002 after giving effect to the Current Bank Facility, the Acquisition of the Initial Properties, the Additional Properties Acquisition and this Offering ⁽⁶⁾
Current Bank Facility ⁽¹⁾⁽²⁾⁽³⁾	US\$60,000,000	\$Nil	\$56,500,000	\$52,300,000
Trust Debenture ^{(4) (9)}	\$5,000,000	\$Nil	\$5,000,000	\$Nil
Interim Loan ⁽⁵⁾	\$43,000,000	\$Nil	\$23,400,000	\$Nil
Trust Units ⁽⁴⁾⁽⁵⁾⁽⁶⁾⁽⁷⁾⁽⁸⁾⁽⁹⁾	Unlimited	\$100 (one hundred Trust Units)	\$100 (one hundred Trust Units)	\$32,600,000 (8,750,000 Trust Units)

Notes:

- (1) Effective June 30, 2002, the Corporation had a borrowing base credit facility with an initial borrowing base of \$18 million with a Canadian chartered bank. The Corporation had drawn \$12 million on this credit facility for purposes of closing the acquisition of the Initial Properties and to finance \$3.0 million of the non-refundable deposit under the Additional Properties Agreement. On November 15, 2002, this facility was repaid in full through an advance made under the Current Bank Facility. See "Initial Properties", "Additional Properties" and "Information Respecting the Corporation – Borrowing".
- (2) In connection with the Additional Properties Acquisition, the Corporation entered into the Current Bank Facility. The Corporation's current indebtedness under the Current Bank Facility is approximately \$56.7 million, of which approximately \$12.3 million was used to repay all outstanding indebtedness under a previous credit facility, approximately \$38.6 million was used to partially fund the Additional Properties Acquisition, approximately \$2.3 million was paid in respect of fees and expenses to establish the Current Bank Facility, with approximately \$2.3 million committed to cover current expenditures and \$1.2 million committed to collateralize outstanding letters of credit. See "Initial Properties", "Additional Properties", "Information Respecting the Corporation – Borrowing" and "Use of Proceeds".
- (3) The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional \$5.7 million adjustment to the Additional Properties Acquisition Cost should be made in favour of the Additional Properties Vendor. This dispute relates to whether or not the value of a hedging contract held by the Additional Properties Vendor impacts the net proceeds from the Additional Properties from the effective date of the Additional Properties Acquisition of June 1, 2002 to the closing date of November 15, 2002. The Additional Properties Vendor has indicated its intent to charge the Corporation the additional \$5.7 million as an interim adjustment within 90 days of the closing of the Additional Properties Acquisition. Management of the Corporation believes that such amount is not owing to the Additional Property Vendor. This dispute is expected to be resolved through an arbitration process established in the Additional Properties Agreement. However, if this amount is not recoverable, the amount will be paid through an additional advance under the Current Bank Facility. See "Additional Properties" and "Risk Factors".
- (4) The Trust Debenture was issued effective as of August 15, 2002 by the Trust in exchange for \$5,000,000 in cash. The Trust Debenture bears interest at 2.25%, is unsecured and is due December 31, 2002. Principal and outstanding interest under the Trust Debenture will be settled in either cash or Trust Units, at the option of the holder. If settled in Trust Units, the dollar amount outstanding will be converted to Trust Units at a fixed price of \$1.00 per Trust Unit. Outstanding amounts due under the Trust Debenture become due and payable on the earlier of the maturity date and the date on which the Trust qualifies as a mutual fund trust through the listing of the Trust Units on a recognized Canadian stock exchange. For purposes of the table above, it is assumed that the Trust Debenture is settled for 5 million Trust Units on completion of the Offering. See "Description of the Trust – Trust Debenture", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".
- (5) Upon closing of the Additional Properties Acquisition, the Trust had borrowed \$22.2 million under the Interim Loan. The Interim Loan bears interest at 20% per annum and was provided by Caribou, which is controlled by M. Bruce Chernoff, a director of the Corporation. The loan is secured by all of the assets of the Trust, including the NPI, but is not secured by the Properties of the

Corporation. The Trust paid these amounts to the Corporation to purchase the NPI and the Initial Direct Royalties from the Corporation and to finance the Deferred Purchase Price Obligation in respect of the Additional Properties Acquisition. See "Acquisition of the NPI", "Initial Properties" and "Additional Properties". The Corporation used these amounts to partially finance the acquisitions of the Initial Properties and the Additional Properties. The Trust will use approximately \$23.4 million from the net proceeds of the Offering to repay the Interim Loan (including accrued interest) and approximately \$4.2 million to partially repay the advance made under the Current Bank Facility which was used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan" and "Use of Proceeds".

- (6) See "Acquisition of the NPI", "Initial Properties" and "Additional Properties". The Trust will use approximately \$23.4 million from the net proceeds of the Offering to repay the Interim Loan (including accrued interest) and approximately \$4.2 million from the net proceeds of the Offering to partially repay the advance made under the Current Bank Facility which was used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan", "Capitalization of the Trust" and "Use of Proceeds".
- (7) The amount outstanding after giving effect to the Offering gives effect to the net proceeds of the Offering of \$27.6 million (\$31.83 million if the Over-allotment Option is exercised) after expenses of the Offering of \$600,000. If the Over-allotment Option is fully exercised, the Trust Units would be \$36,830,000 (9,462,500 Trust Units) and the Current Bank Facility would be reduced to \$48,270,000.
- (8) The initial 100 Trust Units issued to settle the Trust will be cancelled at the closing of the closing of the Offering.
- (9) Pursuant to the Interim Loan, the Trust has issued 150,000 Warrants to Caribou to purchase an equivalent number of Trust Units for \$1.00 each. These Warrants are exercisable until July 31, 2003. See "Description of the Trust – Warrants", "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".

DETAILS OF THE OFFERING

The total Offering consists of 3,750,000 Trust Units and up to an additional 562,500 Trust Units if the Over-allotment Option is exercised in full. The Trust Units are offered hereunder at a price of \$8.00 per Trust Unit.

An unlimited number of Trust Units may be issued pursuant to the Trust Indenture. The Trust may offer additional Trust Units or rights to additional Trust Units at such times and on such terms as the Harvest Board may determine. The Trust Units represent equal undivided beneficial interests in the Trust. All Trust Units share equally in all distributions from the Trust and all Trust Units carry equal voting rights at meetings of Unitholders. No Unitholder is liable to pay any further calls or assessments in respect of Trust Units. No conversion or pre-emptive rights attach to the Trust Units.

The Trust Indenture and the Administration Agreement provides for, among other things, the calling of meetings of Unitholders, the conduct of business thereof, notice provisions, the appointment and removal of the trustee of the Trust and the form of Trust Unit certificates. The Trust Indenture and the Administration Agreement may be amended from time to time. Substantive amendments to the Trust Indenture, including early termination of the Trust and the sale or transfer of the property of the Trust as an entirety or substantially as an entirety, require the approval by a majority of not less than 66 2/3% of the votes cast, either in person or by proxy, at a special meeting of Unitholders or approval in writing by holders of not less than 66 2/3% of the outstanding Trust Units.

Unitholders of record on the last business day of each month are entitled to receive cash distributions of Distributable Cash of the Trust in respect of that month. Such distributions are made on or about the 15th day of the following month. See "Distributions to Unitholders".

PLAN OF DISTRIBUTION

Pursuant to an agreement (the "Underwriting Agreement") dated November 27, 2002, among the Trust, the Corporation and the Underwriters, the Trust has agreed to sell and the Underwriters have severally agreed to purchase on December 5, 2002, or on such later date as may be agreed upon, but in any event not later than December 20, 2002, an aggregate of 3,750,000 Trust Units at a purchase price of \$8.00 per Trust Unit, for an aggregate consideration of \$30 million, payable to the Trust by the Underwriters against delivery of the Trust Units. In consideration of the services provided in connection with this Offering, the Trust will pay the Underwriters a fee of \$0.48 per Trust Unit for an aggregate fee of \$1.8 million.

The obligations of the Underwriters under the Underwriting Agreement are conditional and may be terminated at their discretion on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. The Underwriters are, however, obligated to take up and pay for all of the Trust Units if any of such Trust Units are purchased under the Underwriting Agreement. Each of the Trust and the Corporation has agreed to indemnify the Underwriters and their shareholders, directors, officers, employees, partners, advisors and Underwriters against certain liabilities, including civil liabilities under Canadian, provincial and territorial securities legislation, or to contribute to any payments the Underwriters may be required to make in respect thereof.

Subscriptions for Trust Units will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice.

The Trust has granted to the Underwriters the Over-allotment Option, exercisable until 60 days from the closing of the Offering, to purchase up to an additional 562,500 Trust Units at the Offering Price to cover over-allotments, if any, and for market stabilization purposes. If the Underwriters exercise the Over-allotment Option in full, the Trust will be obligated to issue such Trust Units and will receive a net total of an additional \$4.23 million after deducting fees to the Underwriters of \$270,000. This prospectus also qualifies for distribution of any Trust Units that are issued pursuant to the exercise of the Over-allotment Option.

Pursuant to policy statements of the Ontario Securities Commission and the Commission des valeurs mobilières du Québec, the Underwriters may not, throughout the period of distribution under this prospectus, bid for or purchase Trust Units. The foregoing restriction is subject to certain exceptions, as long as the bid or purchase is not engaged in for the purpose of creating actual or apparent active trading in or raising the price of such securities. These exceptions include a bid or purchase permitted under the by-laws and rules of the TSX relating to market stabilization and passive market making activities and a bid or purchase made for and on behalf of a customer where the order was not solicited during the period of distribution. Subject to the foregoing and applicable laws, the Underwriters may, in connection with the Offering, over-allot or effect transactions which stabilize or maintain the market price of the Trust Units at levels other than those which otherwise might prevail on the open market. Such transactions, if commenced, may be discontinued at any time.

The Trust Units have not been and will not be registered under the United States *Securities Act of 1933*, as amended, or any state securities laws, and the Underwriting Agreement does not contemplate that the Trust Units will be offered or sold within the United States or to U.S. residents.

The TSX has conditionally approved the listing of the Trust Units distributed under this prospectus. Listing will be subject to the Trust fulfilling all of the listing requirements of the TSX on or before February 18, 2003, including distribution of the Trust Units to a minimum number of public Unitholders.

There is currently no market through which the Trust Units may be sold. Accordingly, the terms of the distribution, including the Offering Price of the Trust Units, were determined by negotiation between the Corporation, on behalf of the Trust, and the Underwriters.

The Trust has agreed that it will not, without the prior consent of FirstEnergy Capital Corp. pursuant to the Underwriting Agreement, which consent may not be unreasonably withheld, directly or indirectly, issue, sell, offer to sell, grant any option for the sale of or otherwise dispose of any Trust Units or securities convertible or exercisable into Trust Units or announce the intention to do so, other than pursuant to the Over-allotment Option, the Unit Incentive Plan, the DRIP Plan and as may be required to be issued in settlement of the Trust Debenture, at any time prior to the date which is 180 days following the Closing of the Offering.

As a condition to completion of the Offering, certain members of the Management Group holding an aggregate \$4,042,500 principal amount of the Management Group Debentures have agreed to execute 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 currently held by such holder or such holder's spouse, directly or indirectly, at any time until the date two years following the date of issue of a final receipt for this prospectus. See also "Interests of Management and Others in Material Transactions" and "Risk Factors – Dilution".

M. Bruce Chernoff has agreed to purchase, and the Trust has agreed to sell to Mr. Chernoff or his nominee, up to 625,000 Trust Units at the Offering Price, conditional upon closing of the Offering. The remaining directors and officers of the Corporation have also agreed to purchase up to an aggregate of 224,125 Trust Units. See also "Interests of Management and Others in Material Transactions".

USE OF PROCEEDS

The net proceeds to the Trust from the Offering are estimated to be \$27.6 million, after deducting the fees payable to the Underwriters and the expenses of the Offering (\$31.83 million, if the Over-allotment Option is fully exercised). The Trust

will use approximately \$23.4 million from the net proceeds of the Offering to repay the Interim Loan (including accrued interest) and the balance to partially repay the advance made under the Current Bank Facility which was used to partially fund the Additional Properties Acquisition. as indicated in the table below.

	Assuming Completion of the Offering	Assuming Completion of the Offering with the Exercise of the Over-allotment Option by the Underwriters⁽¹⁾
Repayment of Interim Loan ⁽²⁾	\$23,400,000	\$23,400,000
Partial repayment of the Current Bank Facility ⁽³⁾	\$4,200,000	\$8,430,000
Total	\$27,600,000	\$31,830,000

Notes:

- (1) The Trust has granted to the Underwriters the Over-allotment Option, exercisable for a period of 60 days from the Closing, to purchase up to an additional 562,500 Trust Units at the Offering Price to cover over-allotments, if any, and for market stabilization purposes.
- (2) Repayment of principal and accrued interest. See "Additional Properties", "Description of the Trust – Interim Loan", "Interests of Management and Others in Material Transactions", "Information Respecting the Corporation – Borrowing" and "Use of Proceeds".
- (3) See "Additional Properties", "Interests of Management and Others in Material Transactions", "Information Respecting the Corporation – Borrowing" and "Use of Proceeds".

PRINCIPAL UNITHOLDERS

To the knowledge of the directors and officers of the Corporation, no person or company will beneficially own, directly or indirectly, or exercise control or direction over, in excess of 10% of the Trust Units on a fully-diluted basis on the completion of this Offering other than Mr. Bruce Chernoff who will own or control approximately 4,175,000 Trust Units of 8,900,000 Trust Units outstanding (9,462,500 if the Over-allotment Option is fully exercised by the Underwriters) on completion of the Offering and subsequent settlement of the Trust Debenture and the Management Group Debentures with Trust Units (assuming the payment of interest in cash) and the exercise of the Warrants.

CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Burnet, Duckworth & Palmer LLP, counsel to the Trust, and Blake, Cassels & Graydon LLP, counsel to the Underwriters (collectively referred to herein as "Counsel"), the following summary fairly describes the principal Canadian federal income tax considerations pursuant to the Tax Act generally applicable to a Unitholder who acquires Trust Units pursuant to this Offering and who, for purposes of the Tax Act, is resident in Canada, holds the Trust Units as capital property and deals at arm's length with the Trust and the Underwriters. Generally speaking, Trust Units will be considered to be capital property to a Unitholder provided the Unitholder does not hold the Trust Units in the course of carrying on a business and has not acquired them in one or more transactions considered to be an adventure in the nature of trade. Certain Unitholders who might not otherwise be considered to hold their Trust Units as capital property may, in certain circumstances, be entitled to have them treated as capital property by making the election permitted by subsection 39(4) of the Tax Act. This summary is not applicable to a Unitholder that is a "financial institution", as defined in the Tax Act for purposes of the mark-to-market rules or to a Unitholder an interest in which would be a "tax shelter investment" as defined in the Tax Act and any such Unitholder should consult its own tax advisor with respect to an investment in Trust Units

This summary is based upon the provisions of the Tax Act, the Income Tax Regulations (the "Regulations") in force as of the date hereof, all specific proposals to amend the Tax Act and the Regulations that have been publicly announced prior to the date hereof (the "Proposed Amendments") in the Alberta Corporate Tax Act (the "Alberta Act") and Counsels' understanding of the current administrative policies of the Canada Customs and Revenue Agency ("CCRA"). No advance income tax ruling has been requested in respect of this Offering.

This summary is not exhaustive of all possible Canadian federal income tax considerations and, except for the Proposed Amendments, does not take into account or anticipate any changes in the law, whether by legislative, governmental or judicial action, nor does it take into account provincial (except for certain provisions of the Alberta Act), territorial or foreign tax considerations, which may differ significantly from those discussed herein.

This summary is of a general nature only and is not intended to be legal or tax advice to any prospective purchaser of Trust Units. Consequently, prospective Unitholders should consult their own tax advisors with respect to their particular circumstances.

Status of the Trust

In the opinion of Counsel, the Trust qualifies as a "unit trust" as defined by the Tax Act, and this summary assumes that the Trust will also qualify on Closing, and will continue to qualify thereafter, as a "mutual fund trust" as defined in the Tax Act. The qualification of the Trust as a mutual fund trust requires that certain factual conditions be met throughout its existence. Firstly, in order for the Trust to qualify as a mutual fund trust, it must meet certain criteria with respect to the nature of its assets and it must not be established nor must it at any time be maintained primarily for the benefit of non-residents. Although these facts have been assumed for the purposes of this opinion, Counsel is of the view that such assumption is reasonable in light of the restrictions on the nature of the Trust's investments and on the intention of the Trust to limit ownership of Trust Units by non-resident persons. Secondly, in order for the Trust to continue to qualify as a mutual fund trust, there must be at least 150 Unitholders each of whom owns not less than one "block" of Trust Units having a fair market value of not less than \$500. A "block" of Trust Units means 100 Trust Units if the fair market value of one Trust Unit is less than \$25. It is intended that these requirements will be satisfied so that the Trust will continue to so qualify as a mutual fund trust, but in the event the Trust were not to so qualify, the income tax considerations would in some respects be materially different from those described below. The Trust intends to make an election in order that it will qualify as a mutual fund trust from the commencement of its first taxation year.

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

If the Trust ceases to qualify as a mutual fund trust, the Trust will be required to pay a tax under Part XII.2 of the Tax Act in respect of designated income distributed by the Trust. The payment of Part XII.2 tax by the Trust may have adverse income tax consequences for certain Unitholders including certain non-resident persons, and certain Exempt Plans that acquire an interest in the Trust directly or indirectly from another Unitholder.

Income of the Trust

The Trust will be required to include in computing its income for a taxation year (which will be the calendar year) all amounts that it receives in that year in respect of the NPI and the Direct Royalties, including any amounts subject to set off, and including any amounts paid by it to the Corporation in that year in respect of reimbursed Crown charges in respect of the NPI or in respect of any freehold mineral tax payable in respect of the Direct Royalties. The Trust will also be required to include in its income any interest which accrues to it on unexpended funds or in respect of loans which are made to the Corporation. Any repayments of amounts advanced to the Corporation will not be included in the Trust's income. Any interest expense or other financing expenses incurred by the Trust in respect of borrowing funds to carry out its activities will be deductible by the Trust in the year incurred, to the extent and in the manner prescribed by the Tax Act. Costs incurred in the issuance of Trust Units may generally be deducted by the Trust over a six year period. The Trust will be entitled to deduct reasonable current expenses incurred in its ongoing operation as well as annual deductions in respect of cumulative Canadian oil and natural gas property expense ("COGPE") and resource allowance as described below.

The cost to the Trust of the Direct Royalties and the NPI, including any amount paid under the Deferred Purchase Price Obligation will, when incurred, be added to the Trust's cumulative COGPE account. Any amount which is receivable by the Trust from the sale of Direct Royalties or the release of the NPI will be deducted from the Trust's cumulative COGPE account (see "Deferred Purchase Price Obligation and the Release of the NPI on Certain Properties"). The Trust may deduct, in computing its income from all sources for a taxation year, an amount not exceeding 10%, on a declining basis, proportionately reduced for taxation years of less than 365 days, of any positive balance of its cumulative COGPE account at the end of that year. If the balance of the cumulative COGPE account of the Trust at the end of a particular taxation year after all additions and deductions for that year have been made would otherwise be a negative amount, the negative amount will be included in the Trust's income for the purposes of the Tax Act for that year.

The Trust's resource allowance is computed as being 25% of its adjusted resource profits, calculated in accordance with the Regulations. Generally, the Trust's adjusted resource profits will include its income from the NPI prior to any deduction in respect of its cumulative COGPE and any amount deducted in respect of distributions to Unitholders, as described below. The Trust may not deduct Crown charges reimbursed by it to the Corporation during the year. Resource allowance may only be claimed in respect of the Direct Royalties to the extent that such royalties bear freehold mineral taxes.

The Tax Act requires the Trust to compute its income or loss for a taxation year as though it were an individual resident in Canada. The taxation year of the Trust is the calendar year. To the extent that the Trust has any income for a taxation year after the inclusions and deductions outlined above, the Trust will be permitted to deduct all amounts which are payable by it to Unitholders in the year and any amounts which constitute the excess, if any, of Crown charges reimbursed by the Trust to the Corporation or mineral taxes paid by the Trust over the resource allowance deductible by the Trust for that year, to the extent that such excess amounts are designated to the Unitholders for that year. See "The Unitholders – Income from Trust Units", below. The Trustee has agreed to designate the full amount of any such excess amounts annually in favour of the Unitholders. Accordingly, it is anticipated that the Trust will generally not have any taxable income for the purposes of the Tax Act, however, no assurances can be given in this regard. The Trust may, at its discretion, claim a deduction in computing income for a taxation year in an amount less than its income for the year that becomes payable to Unitholders in the year in order to utilize losses from prior taxation years.

Deferred Purchase Price Obligation and the Release of the NPI on Certain Properties

Where as a result of a sale of a Property by the Corporation and the release of the NPI relating to that Property, an amount becomes receivable by the Trust in a taxation year such amount will be required to be deducted from the balance of the Trust's cumulative COGPE account otherwise determined at the end of that year. If all or a portion of the consideration receivable in a taxation year upon the release of the NPI relating to a Property is used pursuant to the Deferred Purchase Price Obligation to acquire in that year one or more replacement Canadian resource properties, the amount so used will be added, in that year, to the cumulative COGPE account of the Trust to the extent of its share of the portion of the consideration that is so used.

Entitlement to Alberta Royalty Credits

The Trust is entitled to claim ARTC with respect to amounts reimbursed by it to the Corporation for Alberta Crown royalties and other Crown charges which, under the Alberta Act, do not relate to a restricted resource property. Generally, a restricted resource property is an Alberta resource property relating to a completed oil and natural gas well which is disposed of by a person who, either alone or together with persons with which it is associated, receives maximum ARTC for the year prior to the sale of such Alberta resource property. ARTC is based on a price-sensitive formula linked to crude oil prices. Credits vary from a high of 75% of eligible Alberta Crown Royalties when the price of oil falls below U.S. \$15 per barrel, to a low of 25% of Alberta Crown Royalties when the price of oil rises above U.S. \$30 per barrel. The maximum Alberta Crown Royalty to which the rate applies annually is \$2,000,000 per applicant or associated group of applicants. **The Trust will not be required to include any amount of ARTC in its income. Counsel has been advised that the producing wells acquired as part of the Initial Properties from the Initial Properties Vendors are restricted resource properties such that no ARTC will accrue to the Trust thereon.**

The Unitholders

Income from Trust Units

Each Unitholder is required to include in computing income for a particular taxation year the Unitholder's pro rata share of the Trust's income for tax purposes that was payable in that year by the Trust to that Unitholder whether such amounts are paid in the form of additional Trust Units, or constitute cash distributions reinvested in additional Trust Units, and whether the amount was actually paid to the Unitholder in that year, together with all amounts designated to the Unitholder as reimbursed Crown charges in excess of the resource allowance deducted in computing the Trust's income. An amount will be considered to be payable to the Unitholders in a taxation year if it is paid in the year by the Trust or the Unitholder is entitled in that year to enforce payment of the amount. In certain limited cases, such as where the Trust uses income of the Trust to repay the principal amount of Trust borrowings or to purchase additional Direct Royalties, it is possible that such Trust income may be paid to Unitholders through the issuance of Trust Units. Generally income of a Unitholder from the Trust Units will be considered to be income from property and not business income or income from production for purposes of the Tax Act. Any loss of the Trust for purposes of the Tax Act cannot be allocated to and treated as a loss of the Unitholders.

Adjusted Cost Base of Trust Units

The adjusted cost base of a Unitholder of a Trust Unit will include all amounts paid or payable by the Unitholder for a Trust Unit. Any additional Trust Units acquired by a Unitholder on a reinvestment of a distribution by the Trust or a distribution of additional Trust Units will have an initial cost to the Unitholder equal to the amount of the distribution so reinvested or distributed, subject to the averaging provisions of the Tax Act. Amounts distributed by the Trust to a Unitholder in respect of a Trust Unit (including amounts in respect of ARTC, if any) will reduce the Unitholder's adjusted cost base of the Trust Unit to the extent that the amount distributed is in excess of the Trust's income for the purposes of the Tax Act computed prior to any deduction for amounts distributed to Unitholders. To the extent that the adjusted cost base to a holder of Trust Units would otherwise be less than zero, the negative amount will be treated as a capital gain from the disposition of such Trust Units.

Disposition of Trust Units

An actual or deemed disposition of Trust Units (other than in a tax-deferred transaction) will give rise to a capital gain (or capital loss) equal to the amount by which the proceeds of disposition are greater than (or less than) the adjusted cost base to the holder of such Trust Units plus reasonable costs associated with the disposition. In computing income, a taxpayer must include one-half of the amount by which the taxpayer's capital gains for the taxation year exceed his capital losses for that year. Capital gains realized by an individual may give rise to alternative minimum tax.

Unitholders who realize capital losses upon the disposition of Trust Units in a taxation year may deduct such losses from any capital gains realized in that year. Capital losses not applied to reduce capital gains in this manner may be applied against the amount by which capital gains exceed capital losses for each of the three previous or any subsequent taxation year.

Interest on Funds Borrowed to Acquire Units

Reasonable amounts of interest which are paid or payable pursuant to a legal obligation by a Unitholder on borrowed money used to acquire Trust Units will generally be deductible in computing the Unitholder's income for the period during which the person holds the Trust Units. Interest on funds used directly or indirectly to make a contribution to a RRSP is not deductible.

INDUSTRY CONDITIONS

Canadian Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect the operations of the Trust in a manner materially different than they would affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Trust is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing — Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding 1 year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board ("NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

Pricing and Marketing — Natural Gas

In Canada, the price of natural gas sold in interprovincial and international trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³ /day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity

requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

The government of Alberta also regulates the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement ("NAFTA")

On January 1, 1994, NAFTA became effective among the governments of Canada, the United States of America and Mexico. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the United States of America or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period), (ii) impose an export price higher than the domestic price, and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

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

Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties or net profits or net carried interests.

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

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing oil reserves in Alberta. Oil produced from horizontal extensions commenced at least 5 years after the well was originally spudded may also qualify for a royalty reduction. A 24 month, 8,000 cubic metre exemption is available to production from a well that has not produced for a 12 month period, if resuming production after February 1, 1993. As well, oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30, 1992 is entitled to a 12 month royalty exemption (to a maximum of \$1 million). Oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

The Alberta government has also introduced a third tier royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

In the Province of Alberta, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying exploratory natural gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 is eligible for a royalty exemption for a period of 12 months, up to a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible natural gas wells spudded or deepened to a depth below 2,500 meters is also subject to a royalty exemption, the amount of which depends on the depth of the well.

In Alberta, a producer of oil or natural gas is entitled to a credit on qualified oil and natural gas production against the royalties payable to the Crown by virtue of the ARTC program. The ARTC program is based on a price-sensitive formula,

and the ARTC rate varies between 75%, at prices for oil below \$100 per cubic metre, and 25%, at prices above \$210 per m³. The ARTC rate is applied to a maximum of \$2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from corporations claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

On December 22, 1997, the Alberta government announced that it was conducting a review of the ARTC program with the objective of setting out better targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than \$10,000 in royalties per year and non-corporate entities from qualifying for the program.

Oil and natural gas royalty holidays and reductions for specific wells reduce the amount of Crown royalties paid to the provincial governments. In Alberta, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties. Both of these incentives have the effect of increasing the net income of oil and natural gas producers, and in this case, the Trust.

Land Tenure

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

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and natural gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines and penalties.

In Alberta, environmental compliance has been governed by the *Alberta Environmental Protection and Enhancement Act* (the "AEPEA") since September 1, 1993. In addition to replacing a variety of older statutes which related to environmental matters, AEPEA also imposes certain new environmental responsibilities on oil and natural gas operators in Alberta and in certain instances also imposes greater penalties for violations.

Competitive Environment

The oil and natural gas industry has been experiencing a large number of business combinations, involving companies of all sizes. This consolidation process has resulted in a number of asset rationalization programs pursuant to which assets have become available for acquisition. This same consolidation process has resulted in some industry participants, with whom the Trust will be competing for attractive large asset or share acquisitions becoming larger and more competitive, which may increase the demand for acquisitions.

Investors are becoming increasingly aware of the oil and natural gas royalty trust sector and the income trust sector ("Trust Sector"). Management of the Corporation believes that due to the nature of the assets held by royalty trusts, as well as their focus on development and exploitation rather than exploration, investor interest in the oil and natural gas sector has increased with the growing perception that royalty trusts offer an investment vehicle in the oil and natural gas industry that has less risk than more traditional oil and natural gas investments. Consequently, the Trust Sector has recently been able to access the capital markets more readily than traditional oil and natural gas companies. This access to capital has made the Trust Sector a competitor for oil and natural gas property and corporate acquisitions. The Trust Sector has an advantage over oil and natural gas companies in corporate taxation. A number of Canadian-based oil and natural gas companies are currently taxable, having depleted their accumulated tax pools, and therefore they generally assess the merits of potential acquisitions on an after-tax basis. Oil and natural gas royalty trusts and income trusts distribute income to their unitholders. Units of these royalty and income trusts are often held in tax sheltered vehicles such as registered retirement savings plan accounts, and distributions on the units held in such vehicles are thus generally sheltered from immediate taxation.

Non-Canadian companies have been investing heavily in the Canadian oil and natural gas industry by acquiring both property and companies. In particular, companies from the United States have been attracted to the Canadian market to acquire supplies of natural gas, in part by the weakness of the Canadian dollar relative to the United States dollar and the development of additional pipeline facilities for the efficient transmission of natural gas to the United States markets. Management of the Corporation believes this trend will continue to influence Canadian asset valuation parameters and will result in truly North American valuations for Canadian producers.

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 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.

EXPERTS

Certain legal matters relating to the Offering of Trust Units will be passed upon by Burnet, Duckworth & Palmer LLP on behalf of the Trust and the Corporation and by Blake, Cassels & Graydon LLP on behalf of the Underwriters.

Furthermore, the opinions contained under "Canadian Federal Income Tax Considerations" and "Eligibility for Investment" have been provided by Burnet, Duckworth & Palmer LLP and Blake, Cassels & Graydon LLP. John A. Brussa, a member of the Board of Directors of the Corporation, is a Partner of Burnet, Duckworth & Palmer LLP.

As at September 27, 2002, the partners and associates of Burnet, Duckworth & Palmer LLP and Blake, Cassels & Graydon LLP, as a group, beneficially owned, directly or indirectly, less than 1% of the outstanding Trust Units. On completion of the Offering, the partners and associates of Burnet, Duckworth & Palmer LLP as a group, are expected to beneficially own, directly or indirectly, less than 5% of the outstanding Trust Units (less than 5% if the Over-allotment Option is fully exercised by the Underwriters) and the partners and associates of Blake, Cassels & Graydon LLP, as a group, are expected to beneficially own, directly or indirectly, less than 1% of the outstanding Trust Units (less than 1% if the Over-allotment Option is fully exercised by the Underwriters).

LEGAL PROCEEDINGS

Management of the Corporation is not aware of any litigation outstanding, threatened or pending as of the date hereof or against the Trust or the Corporation or relating to the business of the Corporation which would be material to such business.

PROMOTERS

M. Bruce Chernoff and Kevin A. Bennett may be considered to be the promoters of the Trust by reason of their initiative in organizing the business and affairs of the Trust. See "Interests of Management and Others in Material Transactions".

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

M. Bruce Chernoff and Kevin A. Bennett took the initiative of founding and organizing the Corporation and the Trust and their respective businesses. See "Background to the Offering".

Hector J. McFadyen, a director of the Corporation, was recently appointed to the board of directors of Hunting PLC ("Hunting"), a UK-based public corporation engaged in oil and natural gas, oilfield service, and oil and natural gas marketing and distribution activities. Hunting carries on its oil and natural gas marketing and distribution activities through its majority owned subsidiary, Gibson Energy Ltd. ("Gibson"). The Corporation had previously entered into a number of oil price financial hedging contracts with Gibson as described in "Information Respecting the Corporation – Commodity Hedging." The contracts entered into with Gibson are the 2002 and 2003 Canadian dollar-based price swaps and all of the collars

described under that section of this prospectus. The Corporation may execute additional financial hedging contracts with Gibson in the future.

The Trust has issued the Trust Debenture and incurred the Interim Loan pursuant to financing the acquisition of the Initial Properties and the Additional Properties Acquisition. Other than pursuant to the Corporation's previous credit facility and the Current Bank Facility, the Management Group and Caribou have provided all of the financing to date for the Trust and the Corporation.

The Interim Loan was provided by Caribou, a company controlled by M. Bruce Chernoff, a director of the Corporation. To date \$22.2 million is owing under the Interim Loan, which bears interest at 20% per annum and is due on or before July 31, 2003. The Interim Loan is secured by all of the assets of the Trust, including the NPI, but is not secured by the Properties of the Corporation. The Trust intends to repay all amounts outstanding under the Interim Loan with net proceeds from the Offering. See "Capitalization of the Trust", and "Description of the Trust – Interim Loan" and "Use of Proceeds".

It is anticipated that upon completion of the Offering, the Trust Debenture will be settled with 5,000,000 Trust Units and that these Trust Units will be distributed to the Management Group in settlement of the Management Group Debentures. In addition, it is anticipated that the Warrants, issued to Caribou pursuant to the Interim Loan, will be exercised for 150,000 Trust Units on completion of the Offering. Caribou, which is controlled by M. Bruce Chernoff, a director of the Corporation, holds the Warrants. See "Capitalization of the Trust", "Description of the Trust – Trust Management Group Debentures" and "Description of the Trust – Warrants".

Upon completion of the Offering and subsequent settlement of the Trust Debenture and the Management Group Debentures with Trust Units (assuming the payment of interest in cash) and the exercise of the Warrants, the Management Group and Caribou will have acquired 5,150,000 Trust Units of a total of 8,900,000 Trust Units outstanding (9,462,500 if the Over-allotment Option is exercised in full) at a price of \$1.00 each, which is less than the Offering Price. **The possible issuance of these Trust Units to the Management Group and Caribou will result in dilution to the purchasers of Trust Units pursuant to the Offering.** See "Risk Factors – Dilution". Members of the Management Group may also subscribe for Trust Units at the Offering Price pursuant to the Offering.

As a condition to completion of the Offering, certain members of the Management Group holding an aggregate \$4,042,500 principal amount of the Management Group Debentures have agreed to execute 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 currently held by such holder or such holder's spouse, directly or indirectly, at any time until the date two years following the date of issue of a final receipt for this prospectus.

M. Bruce Chernoff has agreed to purchase, and the Trust has agreed to sell to Mr. Chernoff or his nominee, up to 625,000 Trust Units at the Offering Price, conditional upon closing of the Offering. The remaining directors and officers of the Corporation have also agreed to purchase up to an aggregate of 224,125 Trust Units.

RISK FACTORS

The following are certain factors relating to the business of the Trust which prospective investors should carefully consider before deciding whether to purchase Trust Units. 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 prospectus.

Dilution

The Trust has issued the Trust Debenture and the Warrants pursuant to financing the acquisition of the Initial Properties and the intended acquisition of Additional Properties. Other than pursuant to the Corporation's previous credit facility and the Current Bank Facility, the Management Group and Caribou have provided all of the financing to date for the Trust and the Corporation. It is anticipated that upon completion of the Offering, the Trust Debenture will be settled with 5,000,000 Trust Units and that these Trust Units will be distributed to the Management Group in settlement of the Management Group Debentures. Outstanding interest under the Management Group Debentures will be settled in either cash or Trust Units, at the option of the holder. In addition, it is anticipated that the Warrants will be exercised for 150,000 Trust Units on completion of the Offering. Caribou, which is controlled by M. Bruce Chernoff, a director of the Corporation, was issued the

Warrants pursuant to the Interim Loan. See "Capitalization of the Trust", "Description of the Trust – Trust Management Group Debentures" and "Description of the Trust – Warrants".

Upon completion of the Offering and subsequent settlement of the Trust Debenture and the Management Group Debentures with Trust Units (assuming the payment of interest in cash) and the exercise of the Warrants, the Management Group and Caribou will have acquired 5,150,000 Trust Units of a total of 8,900,000 Trust Units outstanding (9,462,500 if the Over-allotment Option is exercised in full) at a price of \$1.00 each, which is less than the Offering Price. **The possible issuance of these Trust Units to the Management Group and Caribou will result in dilution to the purchasers of Trust Units pursuant to the Offering.**

As a condition to completion of the Offering, certain members of the Management Group holding an aggregate \$4,042,500 principal amount of the Management Group Debentures have agreed to execute 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 currently held by such holder or such holder's spouse, directly or indirectly, at any time until the date two years following the date of issue of a final receipt for this prospectus.

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 Trust's Unit Incentive Plan and DRIP Plan. The possible issuance of these Trust Units could result in dilution to the purchasers of Trust Units pursuant to the Offering. See "The Trust Indenture – Issuance of Trust Units", "Trust Unit Incentive Plan" and "DRIP Plan".

Purchase of NPI, the Initial Properties and Initial Direct Royalties

The price paid for the purchase of the NPI, the Initial Properties and the Direct Royalties forming part of the Initial 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 Properties.

Acquisition of Additional Properties

The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional \$5.7 million adjustment to the Additional Properties Acquisition Cost should be made in favour of the Additional Properties Vendor. This dispute relates to whether or not the value of a hedging contract held by the Additional Properties Vendor impacts the net proceeds from the Additional Properties from the effective date of the Additional Properties Acquisition of June 1, 2002 to the closing date of November 15, 2002. The Additional Properties Vendor has indicated its intent to charge the Corporation the additional \$5.7 million as an interim adjustment within 90 days of the closing of the Additional Properties Acquisition. Management of the Corporation believes that such amount is not owing to the Additional Property Vendor. This dispute is expected to be resolved through an arbitration process established in the Additional Properties Agreement. Should the Corporation be unsuccessful in recovering this amount, it will increase the amount of debt outstanding under the Current Bank Facility. This would increase the Corporation's debt service obligations which would have a negative impact on Cash Available for Distribution.

Changes in Legislation

There can be no assurance that income 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 RRSPs, RRIFs and DPSPs ("Exempt Plans"). Where at the end of any month an Exempt Plan holds Trust Units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1% of the fair market value of the Trust Units at the time such Trust Units were acquired by the Exempt Plan. In addition, where a trust governed by an RRSP holds Trust Units that are not qualified investments, the trust will become taxable on its income attributable to the Trust Units 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 NPI Income.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although the Corporation operates the Initial Properties and believes it will become the operator of the Additional Properties, there is no guarantee that it will remain as operator or that the Corporation will operate the Additional Properties or any other Properties it may acquire in 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 the chain of title may not arise to defeat the claim of the Corporation to certain Properties. A reduction of the NPI Income 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 be greater or less than 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 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 Corporation will establish a Reclamation Fund for the purpose of funding its currently estimated future environmental and reclamation obligations based on its current knowledge, there can be no assurance that the Corporation will be able to satisfy its actual future environmental and reclamation obligations. See "Description of the Trust – Reclamation Fund". Should the Corporation be unable to fully fund the cost of remedying an environmental problem, the Corporation might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy. It is difficult to determine if the Canadian government will ratify the Kyoto Protocol and what, if any, impact this 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

The Corporation's indebtedness under the Current Bank Facility is approximately \$56.7 million, of which approximately \$12.3 million was used to repay all outstanding indebtedness under the Corporation's prior credit facility, approximately \$38.6 million was used to partially fund the Additional Properties Acquisition, approximately \$2.3 million was paid in fees and expenses to establish the Current Bank Facility, with approximately \$2.3 million committed to cover current expenditures and \$1.2 million committed to collateralize outstanding letters of credit. See "Initial Properties", "Additional

Properties" and "Use of Proceeds". In addition, the Trust has the Interim Loan outstanding in the aggregate amount of \$22.2 million and has issued the Trust Debenture in the amount of \$5 million. The Interim Loan was provided by Caribou, a company controlled by M. Bruce Chernoff, a director of the Corporation, bears interest at 20% per annum and is due on or before July 31, 2003. The Interim Loan is secured by all of the assets of the Trust, including the NPI, but is not secured against any of the Properties of the Corporation. See "Information Respecting the Corporation – Borrowing", "Information Respecting the Corporation – Capitalization", "Description of the Trust – Trust Debenture", "Description of the Trust – Interim Loan", "Interests of Management and Others in Material Transactions", "Risk Factors – Dilution" and "Use of Proceeds".

The Current Lender was provided with security over all of the assets of the Corporation. If the Corporation and the Trust become unable to pay the Debt Service Charges or otherwise commit an event of default such as declaring bankruptcy, the Current Lender may foreclose on or sell the Properties free from, or together with, the NPI. Pursuant to the Interim Loan, Caribou was provided with security over the assets of the Trust, including the NPI and the Direct Royalties. Should the Trust become unable to service the Interim Loan, or commit an event of default thereunder such as declaring bankruptcy, Caribou may foreclose on the NPI and/or the Direct Royalties.

Dividends and other distributions by the Corporation are prohibited during a default, event of default or an unremedied borrowing base shortfall 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 specifically subordinate to the Current Bank Facility pursuant to a subordination agreement between the Current Lender, the Trustee and the Corporation dated November 14, 2002. This 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 limit the Cash Available For Distribution during a default, event of default or an unremedied borrowing base shortfall under the Current Bank Facility.

The Corporation must meet certain ongoing hedging and financial covenants under the Current Bank Facility and is subject to customary restrictions on its operations and activities, including restrictions on incurring indebtedness, granting of security, the issuance of incremental debt and the sale of its assets. During such time as any lender comprising the Current Lender is not a Canadian resident, payments under the Current Bank Facility to such lender will be subject to certain withholding taxes which the Corporation has agreed to assume and which may increase the effective interest rate paid by the Corporation.

Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of the NPI and Cash Available For Distribution. The Corporation and the Trust may manage the risk associated with fluctuations in interest rates by entering into interest rate swap transactions from time to time. To the extent that the Corporation and the Trust engage in risk management activities, they will be subject to credit risks associated with counterparties with which they contract.

Debt Repayment

The Corporation and the Trust are permitted to borrow funds to finance the purchase of Properties, capital expenditures or other financial obligations or expenditures 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 pursuant to the Deferred Purchase Price Obligation. Debt Service Charges of the Corporation will be deducted in computing NPI Income and Debt Service Charges of the Trust will be deducted in computing Cash Available For Distribution. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of the NPI and Cash Available For Distribution. To the extent that advances under the Current 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 Current Bank Facility, thereby reducing the Cash Available For Distribution. See "Information Respecting the Corporation – Borrowing", "Information Respecting the Corporation – Capitalization" and "Information Respecting the Trust – Capitalization".

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 Corporation intends to retain a portion of the cash flows from the Properties in the Capital 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 Initial Properties or the Additional Properties and may not generate sufficient cash flows to allow the Corporation to generate sufficient NPI Income 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 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.

The average Economic Life of the Initial Properties is 8.3 years and the average Economic Life of the Additional Properties is 10 years. See "Initial Properties – Summary of Selected Reserve Information" and "Additional Properties – Summary of Selected Reserve Information". Economic Life is largely dependent on the accuracy of the reserves and changes in commodity prices, operating costs and royalty rates, all of which could impact the length of time that the reserves associated with the Initial Properties and the Additional Properties can be economically produced.

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 not yet made any distributions.

Impact of Future Capital Expenditures

The Reserve Value of the Initial Properties and the Additional Properties as estimated in the McDaniel Report 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 Initial Properties and the Additional Properties as estimated in the McDaniel Report will be reduced to the extent that such Capital Expenditures on the Initial Properties and the Additional Properties do not achieve the level of success assumed in the McDaniel Report.

Volatility of Commodity Prices

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 Substances production. Prices for Petroleum Substances 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 Substances prices and increases in differentials could have a material adverse effect on the Trust's operations, financial condition and the level of expenditures provided 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 forward 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 credit risks associated with counterparties with which it contracts. In addition, commodity hedge contracts may require, from time to time, margin payments 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 the Current Bank Facility. To the extent that commodity prices increase significantly, Cash Available for Distribution could be negatively affected. See "Information Respecting the Corporation – Commodity Hedging."

Crude Oil Differentials

The Corporation's crude oil production from the Initial Properties and the Additional Properties will be approximately 58% heavy oil and 42% medium oil. Processing medium oil and heavy oil is more expensive than processing conventional light oil, and it yields less valuable products compared to refining light oil; accordingly, producers of heavy oil or medium oil receive lower wellhead prices for their oil. The differential between light oil and heavy oil or medium oil has fluctuated widely during recent years and when considered with the fluctuations of prices for light oil, substantially increases the volatility of prices for heavy oil and medium oil. Any increase in the differential between light oil and heavy oil or medium oil could result in lower prices received for Petroleum Substances production and have a material adverse effect on the Trust's operations, financial condition and the level of expenditures provided 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 lands, reserves 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 Initial Properties acquired by the Corporation, the value of the Additional Properties and the Corporation's ability to close that acquisition, 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 Initial 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 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.

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. The principal investment of the Trust is the NPI Agreement which contains that provision. 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.

Absence of Prior Public Market

Prior to the Offering there has been no public market for the Trust Units. The Offering Price has been determined by negotiations between the Corporation and the Underwriters based on several factors and may bear no relationship to the price at which the Trust Units will trade in the public market subsequent to the Offering. See "Plan of Distribution".

There is presently no market through which the Trust Units may be sold and purchasers may not be able to resell the securities purchased under this prospectus. The Trust does not represent a traditional investment in the oil and natural gas sector.

Net Asset Value

The net asset value of the assets of the Trust from time to time 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 from time to time is also determined by a number of factors which are beyond the control of management and such trading prices may be greater than the net asset value of the Trust's assets.

AUDITORS, REGISTRAR AND TRANSFER AGENT

The auditors of the Trust are KPMG LLP, Chartered Accountants, Suite 1200, 205 – 5th Avenue, Calgary, Alberta, T2P 4B9.

Valiant Trust Company, at its principal office in Calgary, Alberta and through its co-agent, Equity Transfer Services Inc., at its principal office in Toronto, Ontario is the transfer agent and registrar for the Trust Units.

MATERIAL CONTRACTS

The only material contracts entered into by the Trust or by the Corporation during the past two years or to which any of them will become a party on or prior to the closing of this Offering, other than during the ordinary course of business, are as follows:

1. Trust Indenture referred to under "The Trust Indenture";
2. NPI Agreement referred to under "Description of the Trust – NPI and Direct Royalties";
3. Administration Agreement referred to under "Description of the Trust";
4. Current Bank Facility credit agreement referred to under "Information Respecting the Corporation – Borrowing";
5. the subordination agreement referred to under "Information Respecting the Corporation – Borrowing";
6. Underwriting Agreement referred to under "Plan of Distribution";
7. the Direct Royalties Sale Agreements referred to under "Initial Properties" and "Additional Properties";
8. the Trust Debenture referred to under "Description of the Trust – Trust Debenture";
9. the Interim Loan Agreements referred to under "Information Respecting the Corporation – Borrowing" and "Description of the Trust – Interim Loan";
10. the Sale Agreement referred to under "Initial Properties";
11. the Additional Properties Agreement referred to under "Additional Properties"; and
12. the management undertakings referred to under "Plan of Distribution" and "Interests of Insiders and Others in Material Transactions".

During the period of distribution of the Trust Units, copies of the foregoing documents may, following execution if not yet executed, be examined during normal business hours at the offices of Burnet, Duckworth & Palmer LLP, First Canadian Centre, 1400, 350 – 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain provinces and territories of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces and territories, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that such remedies for rescission or damages are exercised by the purchaser

within the time limit prescribed by the securities legislation of the purchaser's province or territory of residence. The purchaser should refer to any applicable provision of the securities legislation of the purchaser's province and territories for the particulars of these rights or consult with a legal advisor.

INDEX TO FINANCIAL STATEMENTS

1. Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999.
2. Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation Years ended December 31, 2001, 2000 and 1999.
3. Balance Sheet Harvest Energy Trust As at July 10, 2002.
4. Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at July 10, 2002 and for the six months ended June 30, 2002 and year ended December 31, 2001.



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		Years ended December 31,		
	June 30,		2001	2000	1999
	2002	2001			
	(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.

INITIAL PROPERTIES

Notes to Schedule of Revenue and Expenses for the Initial Properties

Years ended December 31, 2001, 2000 and 1999

(Information for the six months ended June 30, 2002 and 2001 is unaudited)

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 properties (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

	Six months ended		Years ended December 31,		
	June 30,		2001	2000	1999
	2002	2001			
	(unaudited)		(audited)		
Revenue	\$ 33,227,218	\$ 27,243,737	\$ 57,615,104	\$ 72,026,276	\$ 42,693,456
Royalties	(6,473,818)	(5,442,979)	(11,340,031)	(14,465,051)	(7,268,179)
	26,753,400	21,800,758	46,275,073	57,561,225	35,425,277
Operating costs	6,838,011	6,883,053	12,832,174	8,799,976	7,452,752
Operating income	\$ 19,915,389	\$ 14,917,705	\$ 33,442,899	\$ 48,761,249	\$ 27,972,525

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

ADDITIONAL PROPERTIES

Notes to Schedule of Revenue and Expenses for the Additional Properties

Years ended December 31, 2001, 2000 and 1999

(Information for the six months ended June 30, 2002 and 2001 is unaudited)

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 is expected to close by 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.



Balance Sheet

HARVEST ENERGY TRUST

As at July 10, 2002

AUDITORS' REPORT TO THE TRUSTEE OF HARVEST ENERGY TRUST AND THE DIRECTORS OF HARVEST OPERATIONS CORP.

We have audited the balance sheet of Harvest Energy Trust as at July 10, 2002. This balance sheet is the responsibility of the trust's management. Our responsibility is to express an opinion on this balance sheet based on our audit.

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

In our opinion, the balance sheet presents fairly, in all material respects, the financial position of the trust as at July 10, 2002 in accordance with Canadian generally accepted accounting principles.

(Signed) KPMG LLP

Chartered Accountants

Calgary, Canada
November 27, 2002

HARVEST ENERGY TRUST

Balance Sheet

As at July 10, 2002

Assets

Current assets:

Cash

\$ 100

Unitholders' Equity

Unitholders' equity (note 1)

\$ 100

Subsequent events (note 2)

See accompanying notes to balance sheet.

Approved on behalf of the Board of Directors:

(Signed) "John A. Brussa" _____
Director

(Signed) "Hector J. McFadyen" _____
Director

HARVEST ENERGY TRUST

Notes to Balance Sheet

As at July 10, 2002

1. Formation of the Trust:

Harvest Energy Trust (the "Trust") is an open-ended unincorporated investment trust established under the laws of the Province of Alberta. The Trust issued 100 Trust units on July 10, 2002 for cash proceeds of \$100.

2. Subsequent events:

(a) Bank loans:

Harvest Operations Corp. ("Harvest"), a wholly-owned subsidiary of the Trust, entered into a bank facility agreement with a Canadian bank on July 4, 2002 (the "Initial Facility"). The Initial Facility was a revolving term credit facility to a maximum of \$18 million, bearing interest at the lender's prime rate plus 0.25% per annum and secured by all of the assets of Harvest. Under the Initial Facility, quarterly principal repayments of \$1.5 million commencing September 30, 2002 were required, with an additional payment of \$1.5 million to be made prior to December 31, 2003. The Initial Facility was to revolve until May 31, 2003 at which time the facility was to be converted to a term facility, with the terms to be established by the lender at that time.

On November 14, 2002 Harvest entered into a new term borrowing base credit facility with a U.S. bank (the "New Facility") for U.S. \$60 million. This facility has an initial borrowing base of U.S. \$38 million, bears interest at the lender's prime rate plus an applicable margin in the case of a base rate loan, and at a LIBOR rate or Bankers Acceptance stamping fee plus an applicable margin in the case of a Eurodollar loan or Bankers Acceptance loan. The applicable margin is 1.125% or 1.875% for a base rate loan and 2.125% or 2.875% for a Eurodollar loan or Bankers Acceptance loan, depending on the amount of the borrowing base that is drawn. To secure the credit facility, Harvest granted the lender a first priority lien on all of its assets. Certain restrictive covenants and financial ratios are required to be maintained for the purpose of measuring Harvest's ability to meet its obligation under the credit agreement. The facility will revolve until April 30, 2004 at which time any outstanding principal and interest balances must be repaid. On November 15, 2002 Harvest borrowed \$56.5 million (U.S. \$35.8 million) to repay the Initial Facility and to partially finance the acquisition of the Additional Properties described in note 2(c).

Harvest paid fees totaling approximately \$2.3 million for the New Facility.

HARVEST ENERGY TRUST

Notes to Balance Sheet

As at July 10, 2002

2. Subsequent events (continued):

(b) Interim loan:

On July 10, 2002 and July 30, 2002, the Trust entered into loan agreements (the "Interim Loan") with Caribou Capital Corp. ("Caribou"), a company controlled by a director of Harvest. Caribou advanced \$12.7 million and \$10.0 million to the Trust to partially finance the acquisition of the Initial Properties and Additional Properties, respectively. The Interim Loan, which is to a maximum of \$43 million, bears interest at a rate of 20% per annum, is unsecured and matures on July 31, 2003. Caribou was granted warrants to purchase 150,000 Trust units at \$1.00 per unit as a fee for providing the Interim Loan. The warrants expire on July 31, 2003. The amount outstanding under the Interim Loan, including accrued interest of \$1.2 million, is to be repaid with the proceeds from the unit issue described in note 2(e).

(c) Property acquisitions:

On July 10, 2002 Harvest acquired the Initial Properties for approximately \$26.2 million. Harvest financed the acquisition by borrowing approximately \$13.6 million under the Initial Facility and \$12.7 million under the Interim Loan.

On August 1, 2002 Harvest entered into a purchase and sale agreement to acquire the Additional Properties for approximately \$71.8 million. The acquisition closed on November 15, 2002; cash to close was approximately \$53.2 million utilizing borrowings on the New Facility and Interim Loan. On closing, the vendor of the Additional Properties indicated its intent to charge Harvest an additional \$5.7 million for the Additional Properties. Management of Harvest believe that such amount is not owing to the Additional Properties vendor and accordingly, the additional amount is not included in the cost of the purchase of the Additional Properties. However, this dispute is expected to be resolved through an arbitration process established in the Additional Properties purchase and sale agreement and any amount paid and not recoverable will be funded through an additional advance under the New Facility.

(d) Trust debenture:

On August 15, 2002 the Trust issued a trust debenture (the "Trust Debenture") for proceeds totaling \$5.0 million, of which \$4,042,500 were to directors and officers of Harvest and their associates. The Trust Debenture bears interest at a rate of 2.25% per annum, is unsecured and is due on December 31, 2002. Principal and outstanding interest will be settled in either cash or Trust units, at the option of the holder. If settled in Trust units, the dollar amount outstanding will be converted to Trust units at a fixed price of \$1 per Trust unit.

HARVEST ENERGY TRUST

Notes to Balance Sheet

As at July 10, 2002

2. Subsequent events (continued):

(e) Unit issuance:

Pursuant to an underwriting agreement dated November 27, 2002, the Trust will issue 3,750,000 Trust units for \$27.6 million, net of a 6% underwriters' fee and issue costs, estimated to total approximately \$600,000 (the "Offering"). The net proceeds will be used to repay the Interim Loan and partially repay the New Facility. In addition, the Trust has granted the underwriters an option, exercisable for a period of 60 days from the closing of the Offering, to purchase up to an additional 562,500 Trust units at the Offering price.

In addition, upon the completion of the Offering, the Trust may be required to settle, at the option of the holder, the \$5,000,000 Trust Debenture and interest payable thereon with cash or through the issuance of 5,000,000 Trust units.

The Trust has 150,000 outstanding warrants to purchase Trust units at \$1.00 per unit, which will be exercisable on closing of the Offering.



Unaudited Pro Forma Consolidated Financial Statements of

HARVEST ENERGY TRUST

As at July 10, 2002 and for the six months ended June 30, 2002
and the year ended December 31, 2001

COMPILATION REPORT

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

We have reviewed, as to compilation only, the accompanying unaudited pro forma consolidated balance sheet of Harvest Energy Trust as at July 10, 2002 and the unaudited pro forma consolidated statements of earnings for the six months ended June 30, 2002 and the year ended December 31, 2001. These pro forma consolidated financial statements have been prepared for inclusion in the prospectus dated November 27, 2002.

In our opinion, the unaudited pro forma consolidated balance sheet as at July 10, 2002 and the unaudited pro forma consolidated statements of earnings for the six months ended June 30, 2002 and the year ended December 31, 2001 have been properly compiled to give effect to the assumptions and adjustments described in the notes thereto.

(Signed) KPMG LLP

Chartered Accountants

Calgary, Canada

November 27, 2002

HARVEST ENERGY TRUST

Pro Forma Consolidated Balance Sheet

As at July 10, 2002
(Unaudited)

	Harvest Energy Trust	Initial Properties Acquisition	Trust Debenture Issuance	Additional Properties Acquisition	Trust Unit Issuance	Pro Forma Consolidated
Assets						
Current asset:						
Cash	\$ 100	\$ -	\$ 5,000,000	\$ (3,027,000)	\$ 1,626,900	\$ 3,600,000
Capital assets	-	26,227,000	-	53,200,000	-	79,427,000
Deferred charges	-	-	-	2,300,000	-	2,300,000
	<u>\$ 100</u>	<u>\$ 26,227,000</u>	<u>\$ 5,000,000</u>	<u>\$ 52,473,000</u>	<u>\$ 1,626,900</u>	<u>\$ 85,327,000</u>
Liabilities and Unitholders' Equity						
Bank loans:						
New facility	\$ -	\$ -	\$ -	\$ 56,500,000	\$ (3,923,100)	\$ 52,576,900
Initial facility	-	13,577,000	-	(13,577,000)	-	-
	-	13,577,000	-	42,923,000	(3,923,100)	52,576,900
Trust debenture	-	-	5,000,000	-	(5,000,000)	-
Interim loan	-	12,650,000	-	9,550,000	(22,200,000)	-
	-	26,227,000	5,000,000	52,473,000	(31,123,100)	52,576,900
Unitholders' equity:						
Trust units	100	-	-	-	32,750,000	32,750,100
	<u>\$ 100</u>	<u>\$ 26,227,000</u>	<u>\$ 5,000,000</u>	<u>\$ 52,473,000</u>	<u>\$ 1,626,900</u>	<u>\$ 85,327,000</u>

See accompanying notes to pro forma consolidated financial statements.

HARVEST ENERGY TRUST

Pro Forma Consolidated Statement of Earnings

Six months ended June 30, 2002
(Unaudited)

	Initial Properties	Additional Properties	Adjustments	Notes	Pro Forma Consolidated
Revenue:					
Petroleum and natural gas	\$13,935,019	\$33,227,218	\$ —		\$47,162,237
Royalties	<u>(1,210,816)</u>	<u>(6,473,818)</u>	<u>—</u>		<u>(7,684,634)</u>
	12,724,203	26,753,400	—		39,477,603
Expenses:					
Operating	5,050,362	6,838,011	—		11,888,373
General and administrative	—	—	1,622,000	3(c)	1,622,000
Interest on bank loans	—	—	1,534,000	3(b)	1,534,000
Amortization of deferred charges	—	—	812,000	3(b)	812,000
Depletion, depreciation and site restoration	<u>—</u>	<u>—</u>	<u>12,972,000</u>	3(a)	<u>12,972,000</u>
	5,050,362	6,838,011	16,940,000		28,828,373
Earnings (loss) before taxes	7,673,841	19,915,389	(16,940,000)		10,649,230
Taxes:					
Current and other	—	—	(95,000)	3(d)	(95,000)
Net earnings (loss)	<u>\$ 7,673,841</u>	<u>\$19,915,389</u>	<u>\$ (17,035,000)</u>		<u>\$10,554,230</u>
Net earnings per unit:					
Basic				3(e)	<u>\$ 1.19</u>
Diluted					<u>\$ 1.19</u>

See accompanying notes to pro forma consolidated financial statements.

HARVEST ENERGY TRUST

Pro Forma Consolidated Statement of Earnings

Year ended December 31, 2001

(Unaudited)

	Initial Properties	Additional Properties	Adjustments	Notes	Pro Forma Consolidated
Revenue:					
Petroleum and natural gas	\$ 30,675,360	\$57,615,104	\$ -		\$88,290,464
Royalties	<u>(2,791,810)</u>	<u>(11,340,031)</u>	<u>-</u>		<u>(14,131,841)</u>
	27,883,550	46,275,073	-		74,158,623
Expenses:					
Operating	11,587,364	12,832,174	-		24,419,538
General and administrative	-	-	3,617,000	3(c)	3,617,000
Interest on bank loans	-	-	2,914,000	3(b)	2,914,000
Amortization of deferred charges	-	-	1,624,000	3(b)	1,624,000
Depletion, depreciation and site restoration	<u>-</u>	<u>-</u>	<u>22,309,000</u>	3(a)	<u>22,309,000</u>
	11,587,364	12,832,174	30,464,000		54,883,538
Earnings (loss) before taxes	16,296,186	33,442,899	(30,464,000)		19,275,085
Taxes:					
Current and other	-	-	(190,000)	3(d)	(190,000)
Net earnings (loss)	<u>\$ 16,296,186</u>	<u>33,442,899</u>	<u>\$ (30,654,000)</u>		<u>\$19,085,085</u>
Net earnings per unit:					
Basic				3(e)	<u>\$ 2.14</u>
Diluted					<u>\$ 2.14</u>

See accompanying notes to pro forma consolidated financial statements.

HARVEST ENERGY TRUST

Notes to Pro Forma Consolidated Financial Statements

As at July 10, 2002 and for the six months ended June 30, 2002 and year ended December 31, 2001
(Unaudited)

1. Basis of presentation:

The accompanying unaudited pro forma consolidated financial statements have been prepared by the management of Harvest Operations Corp. ("Harvest") in accordance with accounting principles generally accepted in Canada.

The unaudited pro forma consolidated balance sheet as at July 10, 2002 has been prepared from the audited balance sheet of Harvest Energy Trust (the "Trust") as at July 10, 2002. The unaudited pro forma consolidated statements of earnings for the six months ended June 30, 2002 and the year ended December 31, 2001 have been prepared from the unaudited schedules of revenue and expenses for the Initial Properties and the Additional Properties (collectively referred to as the "Properties") for the six months ended June 30, 2002 and the audited schedules of revenue and expenses for the Properties for the year ended December 31, 2001.

In the opinion of management, the pro forma consolidated financial statements include all material adjustments necessary for their fair presentation in accordance with generally accepted accounting principles in Canada.

The pro forma consolidated financial statements are 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.

It is the recommendation of management that this financial information should be read in conjunction with the financial statements and notes thereto included in this document.

2. Pro forma consolidated balance sheet assumptions and adjustments:

The unaudited pro forma consolidated balance sheet gives effect to the following proposed transactions and assumptions as if they had occurred on July 10, 2002 as follows:

(a) Trust formation:

On July 10, 2002 the Trust was established under the laws of the Province of Alberta as an open-ended unincorporated investment trust.

(b) Bank loans:

Harvest Operations Corp. ("Harvest"), a wholly owned subsidiary of the Trust, entered into a bank facility agreement with a Canadian bank on July 4, 2002 (the "Initial Facility"). The Initial Facility was a revolving term credit facility to a maximum of \$18 million, bearing interest at the lender's prime rate plus 0.25% per annum and secured by a first priority lien on all of the assets of Harvest. Under the Initial Facility, quarterly principal repayments of \$1.5 million commencing September 30, 2002 were required, with an additional payment of \$1.5 million to be made prior to December 31, 2003. The Initial Facility was to revolve until May 31, 2003 at which time the facility was to be converted to a term facility, with the terms to be established by the lender at that time.

HARVEST ENERGY TRUST

Notes to Pro Forma Consolidated Financial Statements, Page 2

As at July 10, 2002 and for the six months ended June 30, 2002 and year ended December 31, 2001
(Unaudited)

2. Pro forma consolidated balance sheet assumptions and adjustments (continued):

(b) Bank loans (continued):

On November 14, 2002 Harvest entered into a new term borrowing base credit facility with a U.S. bank (the "New Facility") for U.S. \$60 million. This facility has an initial borrowing base of U.S.\$38 million, bears interest at the lender's prime rate plus an applicable margin in the case of a base rate loan, and at a LIBOR rate or Bankers Acceptance stamping fee plus an applicable margin in the case of a Eurodollar loan or Bankers Acceptance loan. The applicable margin is 1.125% or 1.875% for a base rate loan and 2.125% or 2.875% for a Eurodollar loan or Bankers Acceptance loan, depending on the amount of the borrowing base that is drawn. To secure the credit facility, Harvest granted the lender a first priority lien on all of its assets. Certain restrictive covenants and financial ratios are required to be maintained for the purpose of measuring Harvest's ability to meet its obligation under the credit agreement. The facility will revolve until April 30, 2004 at which time any outstanding principal and interest balances must be repaid. On November 15, 2002 Harvest borrowed \$56.5 million (U.S. \$35.8 million) to repay the Initial Facility and to partially finance the acquisition of the Additional Properties described in note 2(e).

Harvest paid fees totaling approximately \$2.3 million for the New Facility.

(c) Interim loan:

On July 10, 2002 and July 30, 2002, the Trust entered into loan agreements (the "Interim Loan") with Caribou Capital Corp. ("Caribou"), a company controlled by a director of Harvest. Caribou advanced \$12.7 million and \$10.0 million to the Trust to partially finance the acquisition of the Initial Properties and Additional Properties, respectively. The Interim Loan, which is to a maximum of \$43 million, bears interest at 20% per annum, is unsecured and matures on July 31, 2003. Caribou was granted warrants to purchase 150,000 Trust units at \$1.00 per unit, as a fee for providing the Interim Loan (see note 2(g)). The warrants expire on July 31, 2003. The amount outstanding under the Interim Loan, including accrued interest of \$1.2 million, is to be repaid with the proceeds from the unit issuance described in note 2(g).

(d) Initial Properties acquisition:

On July 10, 2002 Harvest acquired the Initial Properties for approximately \$26.2 million. Harvest financed the acquisition by borrowing approximately \$13.6 million under the Initial Facility and approximately \$12.7 million under the Interim Loan.

HARVEST ENERGY TRUST

Notes to Pro Forma Consolidated Financial Statements, Page 3

As at July 10, 2002 and for the six months ended June 30, 2002 and year ended December 31, 2001
(Unaudited)

2. Pro forma consolidated balance sheet assumptions and adjustments (continued):

(e) Additional Properties acquisition:

On August 1, 2002 Harvest entered into a purchase and sale agreement to acquire the Additional Properties for approximately \$71.8 million. On November 15, 2002 Harvest acquired the Additional Properties for approximately \$53.2 million utilizing borrowings under the New Facility and the Interim Loan. On closing, the vendor of the Additional Properties indicated its intent to charge Harvest an additional \$5.7 million for the Additional Properties. Management of Harvest believe that such amount is not owing to the Additional Properties vendor and accordingly, the additional amount is not included in the cost of the purchase of the Additional Properties. However, this dispute is expected to be resolved through an arbitration process established in the Additional Properties purchase and sale agreement and any amount paid and not recoverable will be funded through an additional advance under the New Facility.

(f) Trust debenture:

On August 15, 2002 the Trust issued a trust debenture (the "Trust Debenture") for proceeds totaling \$5.0 million, of which \$4,042,500 were to directors and officers of Harvest and their associates. The Trust Debenture bears interest at 2.25% per annum, is unsecured and is due December 31, 2002. Principal and outstanding interest will be settled in either cash or Trust units, at the option of the holder. If settled in Trust units, the dollar amount outstanding will be converted to Trust units at a fixed price of \$1 per Trust unit.

(g) Unit Issuance:

Pursuant to an underwriting agreement dated November 27, 2002 the Trust will issue 3,750,000 Trust units for \$27.6 million, net of a 6% underwriters' fee and issue costs, estimated to be \$600,000 (the "Offering"). The net proceeds will be used to repay the Interim Loan and to partially repay the New Facility. In addition, the Trust has granted the underwriters an option, exercisable for a period of 60 days from the closing of the Offering, to purchase up to an additional 562,500 Trust units at the Offering price. The pro forma consolidated balance sheet assumes that this option will not be exercised.

In addition, upon completion of the Offering, the Trust may be required to settle, at the option of the holder, the \$5.0 million outstanding Trust Debenture with cash or through the issuance of 5,000,000 Trust units. The pro forma consolidated balance sheet assumes that the Trust Debenture will be settled through the issuance of 5,000,000 Trust units.

The Trust has 150,000 outstanding warrants to purchase Trust units at \$1.00 per unit, which will be exercisable on closing of the Offering. The pro forma consolidated balance sheet assumes these warrants will be exercised.

HARVEST ENERGY TRUST

Notes to Pro Forma Consolidated Financial Statements, Page 4

As at July 10, 2002 and for the six months ended June 30, 2002 and year ended December 31, 2001
(Unaudited)

3. Pro forma consolidated statements of earnings assumptions and adjustments:

The pro forma consolidated statements of earnings for the six months ended June 30, 2002 and the year ended December 31, 2001 have been prepared assuming that the transactions described in note 2 were completed on January 1, 2002 and January 1, 2001, respectively:

- (a) The pro forma consolidated statements of earnings reflect a provision for depletion, depreciation and site restoration using the full cost method of accounting based on the combined proved reserves and production volumes of the Properties and incorporating the acquisition costs.
- (b) The pro forma consolidated statements of earnings reflect an increase in financing charges as a result of bank borrowings on the acquisition of the Properties.

Interest charges have been determined assuming an effective interest rate of 6.125% per annum (based upon a lender's prime rate of 4.25% per annum and an applicable margin of 1.875% per annum). The U.S. dollar borrowings under the New Facility have been translated at an exchange rate of approximately \$1.58 Cdn to \$1.00 U.S. It has been assumed that there was no change in the Cdn to U.S. dollar exchange rate during the periods and therefore no adjustment to earnings was necessary for exchange rate changes.

The pro forma consolidated statements of earnings reflect the amortization of deferred charges, which will be amortized over the 17 month term of the New Facility.

- (c) The amounts included in the statements of earnings for general and administrative expenses have been determined on the basis of \$0.90 per barrel of oil equivalent of production from the Properties for the respective periods. General and administrative costs are considered corporate costs and are not allocated or assigned to particular properties, and are therefore not available on an historical basis for the Properties. General and administrative costs incurred by the vendors of these Properties are less relevant given the different nature of their operations to those which will be carried on by the Trust. Management of Harvest has reviewed the financial statements of four other public energy trusts which are similar in size to the Trust and has used the average of their per barrel of oil equivalent general and administrative expense for the six months ended June 30, 2002 for the purposes of determining the general and administrative expense included in the pro forma statements of earnings.

HARVEST ENERGY TRUST

Notes to Pro Forma Consolidated Financial Statements, Page 5

As at July 10, 2002 and for the six months ended June 30, 2002 and year ended December 31, 2001
(Unaudited)

3. Pro forma consolidated statements of earnings assumptions and adjustments (continued):

- (d) 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 remaining taxable income, if any, to the unitholders. Accordingly, no future income taxes have been included in the pro forma statements of earnings. Current and other taxes reflect a provision for capital taxes.
- (e) The net earnings per unit calculations give effect to the issuance of the Trust units as described in note 2(g) as if the units had been issued at the beginning of the respective periods.

CERTIFICATE OF THE TRUST AND PROMOTERS

Dated: November 27, 2002

The foregoing constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by Part 9 of the *Securities Act* (British Columbia), by Part 8 of the *Securities Act* (Alberta), by Part XI of the *Securities Act* (Saskatchewan), by Part VII of the *Securities Act* (Manitoba), by Part XV of the *Securities Act* (Ontario), by Section 13 of the *Security Frauds Prevention Act* (New Brunswick), by Section 64 of the *Securities Act* (Nova Scotia), by Part II of the *Securities Act* (Prince Edward Island), by Part XIV of the *Securities Act* (Newfoundland), by the *Securities Act* (Yukon), by the *Securities Act* (Northwest Territories) and by the *Securities Act* (Nunavut) and the respective regulations thereunder. This prospectus does not contain any misrepresentation that is likely to affect the value or the market price of the securities to be distributed within the meaning of the *Securities Act* (Québec) and the regulations thereunder.

HARVEST ENERGY TRUST

By: Harvest Operations Corp.

(Signed) "*Jacob Roorda*"
President and Chief Executive Officer

(Signed) "*M. Bruce Chernoff*"
Acting as Chief Financial Officer

On behalf of the Board of Directors

(Signed) "*Verne G. Johnson*"
Director

(Signed) "*Hector McFadyen*"
Director

PROMOTERS

(Signed) "*M. Bruce Chernoff*"

(Signed) "*Kevin A. Bennett*"

CERTIFICATE OF THE UNDERWRITERS

Dated: November 27, 2002

To the best of our knowledge, information and belief, the foregoing constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by Part 9 of the *Securities Act* (British Columbia), by Part 8 of the *Securities Act* (Alberta), by Part X1 of the *Securities Act* (Saskatchewan), by Part VII of the *Securities Act* (Manitoba), by Part XV of the *Securities Act* (Ontario), by Section 13 of the *Security Frauds Prevention Act* (New Brunswick), by Section 64 of the *Securities Act* (Nova Scotia), by Part II of the *Securities Act* (Prince Edward Island), by Part XIV of the *Securities Act* (Newfoundland), by the *Securities Act* (Yukon), by the *Securities Act* (Northwest Territories) and by the *Securities Act* (Nunavut) and the respective regulations thereunder. This prospectus does not contain any misrepresentation that is likely to affect the value or the market price of the securities to be distributed within the meaning of the *Securities Act* (Québec) and the regulations thereunder.

FirstEnergy Capital Corp.

By: (signed) "*John S. Chambers*"

Haywood Securities Inc.

By: (signed) "*Fabio M. Banducci*"