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. These securities have not been and will not be registered under the United States Securities Act of 1933, as amended. Accordingly, except to the extent exempt from such registration requirements, these securities may not be offered or sold in the United States and this prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of these securities within the United States. See "Plan of Distribution".

New Issue **March 7, 2003**

PROSPECTUS

1,500,000 Trust Units issuable

on exercise of 1,500,000 Special Warrants

Harvest Energy Trust (the "**Trust**") is hereby qualifying for distribution 1,500,000 Trust Units of the Trust (the "**Qualified Units**") issuable upon exercise of 1,500,000 issued and outstanding special warrants (the "**Special Warrants**"). The Special Warrants were issued on February 4, 2003 (the "**Closing Date**") pursuant to the Special Warrant Indenture (as defined herein) and sold to purchasers in the provinces of Alberta, British Columbia and Ontario (collectively, the "**Filing Provinces**") on a private placement basis pursuant to prospectus exemptions under applicable securities legislation through FirstEnergy Capital Corp. and Haywood Securities Inc. (collectively, the "**Underwriters**"). The Special Warrants are not available for purchase pursuant to this prospectus. See "Plan of Distribution".

The issue price of $10.00 per Special Warrant was determined by negotiation between Harvest Operations Corp. ("**Harvest**" or the "**Corporation**"), a wholly-owned subsidiary of and manager of the Trust, on behalf of the Trust, and the Underwriters. No commission or fee will be payable to the Underwriters by the Trust in connection with the distribution of the Qualified Units upon the exercise of the Special Warrants.

	Offering Price	**Underwriters' Fee** (1)	**Net Proceeds** (2)
Per Special Warrant	$ 10.00	$ 0.50	$ 9.50
Total	$ 15,000,000	$ 750,000	$ 14,250,000

Notes:

(1) The Trust paid a fee of 5% to the Underwriters in connection with the sale of the Special Warrants. No commission or fee is payable to the Underwriters in connection with the distribution of the Qualified Units upon the exercise of the Special Warrants.

(2) Before deducting the expenses in connection with the issuance of the Special Warrants and qualification for distribution of the Qualified Units estimated to be $200,000.

Each Special Warrant entitles the holder to acquire, subject to adjustment, at no additional cost, one Qualified Unit at any time until 5:00 p.m. (Calgary time) on the earlier of: (i) five (5) Business Days (as defined herein) after the Final Receipt Date (as defined herein); and (ii) the first anniversary of the Closing Date (the first of such events to occur is hereinafter referred to as the "**Expiry Time**").

In the event that a Final MRRS decision document (as defined herein) is not obtained by the Trust on or prior to the Qualification Deadline (as defined herein) on behalf of the Canadian securities regulatory authority in each of the Filing Provinces, then each holder of Special Warrants in each of the Filing Provinces on whose behalf a Final MRRS decision document has not been obtained (or, if a Final MRRS decision document has not been obtained on behalf of the Province of Alberta, all holders wherever resident) shall be entitled after the Qualification Deadline to receive on the exercise or deemed exercise of the Special Warrants an additional 0.09 of a Trust Unit for each such Special Warrant so exercised without additional payment. Special Warrants not previously exercised by the holders thereof shall be deemed to be exercised immediately prior to the Expiry Time without further action on the part of the holder. The Trust will continue to use its best efforts to obtain a Final MRRS decision document on behalf of the Canadian securities regulatory authority in each Filing Province where a Final MRRS decision document is not obtained on or before the Qualification Deadline until February 4, 2004.

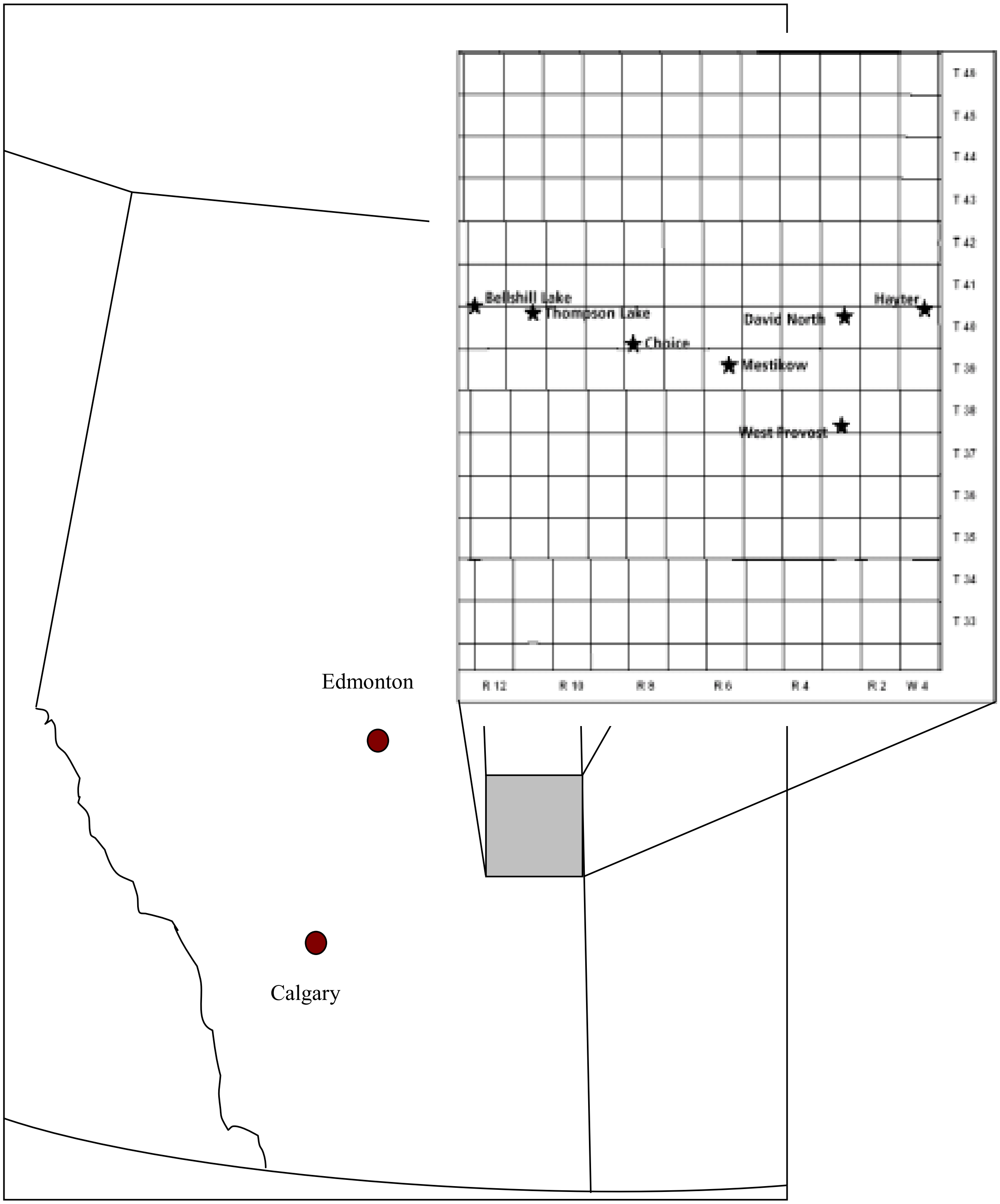
Any Trust Units issued upon the exercise of Special Warrants prior to the Final Receipt Date will be subject to relevant hold periods under applicable securities legislation.

An investment in the Qualified Units is highly speculative due to a number of risks, including: (i) the volatility of oil, natural gas and natural gas product prices; (ii) 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. See "Risk Factors".

The Trust Units are listed and posted for trading on the Toronto Stock Exchange (the "**TSX**") under the trading symbol "HTE". The TSX has conditionally approved the listing of the Qualified Units subject to the Trust fulfilling all of the requirements of such exchange. On January 16, 2003, being the day of negotiation of the issue price of the Special Warrants, the closing price of the Trust Units on the TSX was $10.75. On March 6, 2003, being the last day on which the Trust Units traded prior to the date of this prospectus, the closing price of the Trust Units on the TSX was $11.45. See "Price Range and Trading Volume".

Certificates for the Trust Units will be available for delivery within five (5) Business Days from the date of the exercise or deemed exercise of the Special Warrants. Certain legal matters in connection with this offering will be reviewed on behalf of the Trust and the Corporation by Burnet, Duckworth & Palmer LLP, and on behalf of the Underwriters by Blake, Cassels & Graydon LLP.

PROPERTIES OF THE TRUST



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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

The Trust is hereby providing cautionary statements identifying important factors that could cause the Trust's actual results to differ materially from those projected in forward-looking statements made in this 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 funds that the Trust retains from the Cash Available For Distribution to finance future acquisitions and development of the Properties less amounts paid in respect of acquisitions and development of the Properties. Capital Fund retentions may range from 0% to 50% of the annual Cash Available For Distribution.

"Caribou" means Caribou Capital Corp.

"Cash Available For Distribution" means, for any particular period, the 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 Date" means February 4, 2003, being the date on which the Trust issued the Special Warrants.

"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.

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

"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.

"Expiry Date" means, the earlier of: (i) five (5) Business Days after the Final Receipt Date; and (ii) the first anniversary of the Closing Date.

"Expiry Time" means 5:00 p.m. (Calgary time) on the Expiry Date.

"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.

"**Filing Provinces**" means, collectively, the provinces of Alberta, British Columbia and Ontario.

"**Final MRRS decision document**" means the document issued by the principal regulator under the Mutual Reliance Procedures that evidences that final receipts of the Securities Commission have been issued for the Final Prospectus.

"**Final Prospectus**" means the final prospectus of the Trust which qualifies the distribution of the Trust Units issuable upon the exercise of the Special Warrants.

"**Final Receipt Date**" means the latest date on which a Final MRRS decision document for the Final Prospectus is issued by the Alberta Securities Commission, as principal regulator of the Trust under the Mutual Reliance Procedures, on behalf of Canadian securities regulatory authorities in each of the Filing Provinces.

"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 The 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 $26.1 million.

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

"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 the production costs under the NPI Agreement 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, which were repaid in full from the proceeds of the Initial Public Offering. See "Description of the Trust – Interim Loan".

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

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

"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).

"Mutual Reliance Procedures" means the mutual reliance review system procedures provided under National Policy 43-201, Mutual Reliance Review System for Prospectuses and Annual Information Forms, of the Canadian Securities Administrators.

"Non-Deductible Crown Royalties" means Crown royalties which are: (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 issuable by the Corporation in series pursuant to a note indenture to be redeemed in consideration for a portion of the NPI, having a fair market value equal to such principal amount, and being subject to the following terms and conditions:

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

(b) being subordinate to all senior indebtedness which includes all indebtedness for borrowed money or owing in respect of property purchases on any default in payment of any such senior indebtedness, and to all trade debt of the Corporation or any subsidiary of the Corporation or the Trust on any creditor proceedings such as bankruptcy, liquidation or insolvency;

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

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

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

"NPI" means 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 includes, without limitation, those costs 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 the NPI Income is calculated means 99% of production revenues from the Properties less 99% of the amount by which all the NPI Deductions for such period exceeds the aggregate, without duplication, for such period of: (A) acquisition costs associated with an acquisition of certain rights and other interests under the NPI Agreement paid with the proceeds from the sale of Properties; (B) withdrawals from the Reserve Fund or Reclamation Fund to fund payment of the NPI Deductions; and (C) advances made pursuant to the Credit Facilities to fund the payment of the NPI Deductions less 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 is not a Permitted Investment if it:

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

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

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

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

"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 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 from time to time by the Corporation (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.

"Qualification Deadline" means 5:00 p.m. (Calgary time) on May 5, 2003.

"Qualified Units" means the Trust Units issuable upon exercise of the Special Warrants and which are being qualified for distribution by the Final Prospectus.

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

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

"Reserve Fund" means the cumulative amount of production 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 the 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 revenues used to calculate the NPI Income or the net proceeds of a disposition of the Petroleum and Natural Gas Rights subject to the NPI and includes, without limitation, net revenues relating to the 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, the 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.

"Securities Commission" means, collectively, the applicable securities commissions or similar securities regulatory authorities in the Filing Provinces.

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

"Special Warrant Indenture" means the special warrant indenture entered into between the Trust, the Corporation and the Warrant Trustee dated effective as of the Closing Date governing the terms and conditions of the Special Warrants.

"Special Warrants" means the 1,500,000 special warrants of the Trust created and issued pursuant to the Special Warrant Indenture entitling the holders thereof to acquire, subject to adjustment, one Qualified Unit for each Special Warrant.

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

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

(b) 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 Trust Debenture was settled on closing of the Initial Public Offering with the issuance of 5,000,000 Trust Units. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust" and "Interests of Management and Others in Material Transactions".

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

(a) the amount paid to settle the Trust;

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

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

(d) all rights in respect of and income generated under the NPI Agreement, 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.

"Underwriting Agreement" means the underwriting agreement entered into between the Trust and the Underwriters dated effective February 4, 2003, with respect to the sale of the Special Warrants.

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

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

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

"Warrant Trustee" means Valiant Trust Company, in its capacity as trustee under the Special Warrant Indenture.

"Warrants" means 150,000 warrants to purchase 150,000 Trust Units at $1.00 per Trust Unit issued in connection with the Interim Loan which were exercised by the holder thereof on January 23, 2003. See "Description of the Trust – Warrants", "Capitalization of the Trust" and "Interests of Management and Others in Material Transactions".

"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		Natural Gas	
Bbl	Barrel	Mcf	thousand cubic feet
Bbls	Barrels	Mmcf	million cubic feet
Mbbls	thousand barrels	Bcf	billion cubic feet
Bbls/d	barrels per day	Mcf/d	thousand cubic feet per day
Mmbbls	million barrels	Mmcf/d	million cubic feet per day
NGLs	natural gas liquids	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.
ºAPI	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
MW	megawatts of electricity.

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

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

PROSPECTUS SUMMARY

The following is a summary of the principal features of this distribution 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

The Trust: The Trust is a publicly traded oil and natural gas energy trust engaged, through its wholly-owned subsidiary, Harvest, in the exploration for, and the acquisition, development and production of, oil and natural gas reserves primarily in the Province of Alberta. See "Description of the Trust" and "Information Respecting the Corporation".

The Offering: 1,500,000 Qualified Units issuable on the exercise or deemed exercise of 1,500,000 issued and outstanding Special Warrants. See "Plan of Distribution".

Price: Each Special Warrant entitles the holder thereof to acquire, at no additional cost, one Qualified Unit of the Trust at any time until 5:00 p.m. (Calgary time) on the earlier of five (5) Days after the after the Final Receipt Date and the first anniversary of the Closing Date. The Special Warrants were issued on the Closing Date pursuant to prospectus exemptions under applicable securities legislation at a price of $10.00 per Special Warrant. The offering price of the Special Warrants was determined by negotiation between Harvest, on behalf of the Trust, and the Underwriters.

Qualified Units: 1,500,000 Trust Units issuable upon exercise of 1,500,000 outstanding Special Warrants which were issued on the Closing Date pursuant to prospectus exemptions under applicable securities legislation at a price of $10.00 per Special Warrant resulting gross proceeds of $15,000,000. This prospectus is hereby qualifying for distribution the Trust Units issuable upon exercise of the Special Warrants.

Exercise Details: Each Special Warrant entitles the holder thereof to acquire, subject to adjustment, at no additional cost, one Qualified Unit at any time until 5:00 p.m. (Calgary time) on the earlier of: (i) five (5) Business Days after the Final Receipt Date; and (ii) the first anniversary of the Closing Date. Any Trust Unit issued upon the exercise of Special Warrants prior to the Final Receipt Date will be subject to relevant hold periods under applicable securities legislation. Any Special Warrants not previously exercised by holders thereof shall be deemed to have been exercised immediately prior to the Expiry Time. As at the date hereof, none of the Special Warrants have been exercised.

In the event that a Final MRRS decision document is not obtained by the Trust on or prior to the Qualification Deadline on behalf of the Canadian securities regulatory authority in each of the Filing Provinces, then each holder of Special Warrants in each of the Filing Provinces on whose behalf a Final MRRS decision document has not been obtained (or, if a Final MRRS decision document has not been obtained on behalf of the Province of Alberta, all holders wherever resident) shall be entitled after the Qualification Deadline to receive on the exercise or deemed exercise of the Special Warrants an additional 0.09 of a Trust Unit for each such Special Warrant so exercised without additional payment. Special Warrants not previously exercised by the holders thereof shall be deemed to be exercised immediately prior to the Expiry Time without further action on the part of the holder. The Trust will continue to use its best efforts to obtain a Final MRRS decision document on behalf of the Canadian securities regulatory authority in each Filing Province where a Final MRRS decision document is not obtained on or before the Qualification Deadline until February 4, 2004.

Use of Proceeds: The gross proceeds realized by the Trust from the issuance of the Special Warrants was $15,000,000 (before deducting the Underwriters' fee of $750,000 and the expenses in connection with the issuance of the Special Warrants and the qualification for distribution of the Qualified Units, estimated to be $200,000, which will be paid out of the general funds of the Trust) which were used by the Trust to partially repay the advance made under the Current Bank Facility which was used previously to partially fund the Additional Properties Acquisition and for working capital. See "Use of Proceeds".

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, and if such date of payment is not a Business Day then such payment will be made on the next Business Day. Holders of Special Warrants of record on a Record Date will be entitled to receive monthly cash distributions of Distributable Cash in accordance with the terms of the Special Warrant Indenture. See "Plan of Distribution".

The Trust retains 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".

Recent Developments

The Corporation was incorporated on May 14, 2002 to carry on oil and natural gas acquisition, development and production activities. 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 to meet its objectives. 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 the Initial Properties Vendors on July 10, 2002. See "Acquisition of the 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 now 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 the 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 the Additional Properties Vendor 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.

On December 5, 2002, the Trust completed the Initial Public Offering, which resulted in aggregate gross proceeds of $34,500,000. Approximately $22.2 million from the net proceeds of the Initial Public Offering was used to repay the Interim Loan (including accrued interest) and approximately $5.4 million from the net proceeds of the Initial Public Offering was used to partially repay the advance made under the Current Bank Facility which had been used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan" and "Capitalization of the Trust".

On December 17, 2002, the Trust issued 562,500 Trust Units to the Underwriters as a result of the exercise by the Underwriters of an over-allotment option granted to them in connection with the Initial Public Offering. The $4.2 million in net proceeds from the sale of such Trust Units were used to partially repay the advance made under the Current Bank Facility which had been used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan" and "Capitalization of the Trust".

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 September 30, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at September 30, 2002 and for the nine months ended September 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, wellsite restoration costs and salvage recovery, 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(1)

	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								
Producing Reserves	9,251	8,225	1,348.3	1,078.8	99,174	83,660	77,911	73,079
Non-Producing Reserves	1,903	1,565	298.1	232.9	18,378	14,416	12,882	11,567
Total Proved Reserves	11,154	9,790	1,646.4	1,311.7	117,552	98,076	90,793	84,646
Risked Probable Reserves	1,272	1,113	169.9	133.1	15,200	10,439	8,927	7,763
Established Reserves	12,426	10,903	1,816.2	1,444.8	132,752	108,515	99,720	92,409

Notes:

(1) See Notes (2) through (11) to "Initial Properties – Oil and Natural Gas Reserves" and Note 3 to "Additional Properties – Oil and Natural Gas Reserves".

(2) Columns may not add due to rounding.

Pro Forma Petroleum and Natural Gas
Reserves and Pre-Tax Net Cash Flows
Constant Cost and Price Case(1)

	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)	Net (1)	Gross (1)	Net (1)	0%	10%	15%	20%
Proved Reserves								
Producing Reserves	9,254	8,218	1,349.0	1,079.4	127,416	104,243	95, 835	88,860
Non-Producing Reserves	1,903	1,564	298.1	232.9	22,139	17,376	15, 544	13,978
Total Proved Reserves	11,157	9,782	1,647.1	1,312.3	149,555	121,619	111, 379	102,838
Risked Probable Reserves	1,272	1,112	169.9	133.1	19,508	13,092	11, 075	9,534
Established Reserves	12,429	10,893	1,817.0	1,445.4	169,063	134,711	122,454	112,372

Notes:

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

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".

- **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.

	9 Month Period Ended September 30, 2002[2]	**Year Ended December 31,**[1]		
		2001	**2000**	**1999**
	(unaudited)	(unaudited)	(unaudited)	(unaudited)
Crude oil and natural gas liquids (Mbbls)	2,634	3,938	3,642	3,326
Average daily production (Bbls/d)	9,649	10,789	9,980	9,112
Natural gas sales (Mmcf)	323	481	345	381
Average daily sales (Mcf/d)	1,182	1,315	946	1,042
Total oil equivalent (MBOE)	2,688	4,018	3,700	3,389
Average daily production (BOE/d)	9,840	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) 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.
(3) 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.

	9 Month Period Ended September 30, 2002[(1)]	Year Ended December 31, [(1)(2)]		
		2001	2000	1999
	($000's) (unaudited)	($000's)	($000's)	($000's)
Revenue:				
Petroleum and natural gas sales [(1)]	79,536	88,290	118,422	73,199
Royalties	9,438	14,132	18,872	10,253
Operating expenses	20,299	24,419	18,133	14,719
Operating Income	49,799	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 September 30, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at September 30, 2002 and for the nine months ended September 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;

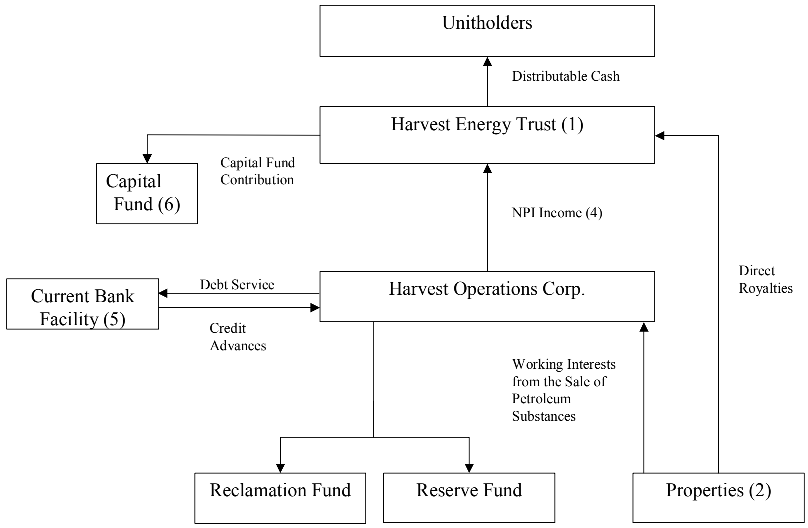
(d) disposing of any part of the Trust Fund, including, without limitation, any securities of the Corporation;

(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 Unit, 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 the 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 – the NPI and Direct Royalties", "Acquisition of the 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 makes regular monthly payments to the Trust in the amount of the NPI Income. See "Description of the Trust – the NPI and Direct Royalties".

(5) The gross proceeds realized by the Trust from the issuance of the Special Warrants of $15,000,000 (before deducting the Underwriters' fee of $750,000 and the expenses in connection with the issuance of the Special Warrants and the qualification for distribution of the Qualified Units, estimated to be $200,000, which will be paid out of the general funds of the Trust) were used by the Trust to partially repay the advance made under the Current Bank Facility which was used previously to partially fund the Additional Properties Acquisition. See "Information Respecting the Corporation – Borrowing", "Capitalization of the Trust" and "Use of Proceeds".

(6) The Trust retains 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 share equally in Distributable Cash paid to Unitholders 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 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. The Board of Directors then reviewed its strategic alternatives and based on such review determined that the formation of an energy royalty trust was the optimal structure. On July 10, 2002, the Trust was formed pursuant to the Trust Indenture. On the same date, the Corporation and the Trust entered into the NPI Agreement. See "Recent Developments".

The Corporation currently has a board of directors consisting of 5 individuals. Subject to the ability of the directors of the Corporation to appoint additional directors between meetings and to fill vacancies, 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 elect 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 37 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 are and will continue to be pursued on a balanced basis to enhance benefits to the Unitholders.

Risk Factors

An investment in the Trust Units is 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; (iii) depletion and recoverability of reserves; (iv) environmental concerns; (v) the Trust's and the Corporation's ability to service any outstanding debt; (vi) the Trust's and the Corporation's ability to obtain additional financing; (vii) changes in legislation; (viii) the nature of oil and natural gas operations; (ix) reliance on the Corporation; (x) any conflicts or potential conflicts of interest; (xi) investment eligibility; (xii) the nature of the Trust Unit form of security; and (xiii) any 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 retains 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 $5.8 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 $5.8 million as an interim adjustment within 90 days and in any event not later than 180 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 the arbitration process established in the Additional Properties Agreement. See "Risk Factors".

The Trust Indenture provides that Unitholders are not liable for or in respect of the obligations of the Trust and that any contracts entered into on behalf of the Trust are not to be personally binding on the Trustee, the Corporation or any Unitholder and any liability is 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 as a result of the development projects intended to be undertaken 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. Investors should carefully consider the information set forth under "Risk Factors" and the other information set forth herein.

RECENT DEVELOPMENTS

The Corporation was incorporated on May 14, 2002 to carry on oil and natural gas acquisition, development and production activities. The Board of Directors then reviewed its strategic alternatives and based on such review determined that the formation of an energy royalty trust was the optimal structure. On July 10, 2002, the Trust was formed pursuant to the Trust Indenture. On the same date, the Corporation and the Trust entered into the NPI Agreement. The Corporation's first transaction was the purchase of the Initial Properties and the Initial Direct Royalties from the Initial Properties Vendors on July 10, 2002. See "Acquisition of the 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 using 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 the NPI" and "Initial Properties – Acquisition of Initial Properties and Initial Direct Royalties".

The 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 the Additional Properties Vendor 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.

On December 5, 2002, the Trust completed the Initial Public Offering, which resulted in aggregate gross proceeds of $34,500,000. Approximately $22.9 million from the net proceeds of the Initial Public Offering was used to repay the Interim Loan (including accrued interest) and approximately $5.4 million from the net proceeds of the Initial Public Offering was used to partially repay the advance made under the Current Bank Facility which had been used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan" and "Capitalization of the Trust".

On December 17, 2002, the Trust issued 562,500 Trust Units to the Underwriters as a result of the exercise by the Underwriters of an over-allotment option granted to them in connection with the Initial Public Offering. The $4.2 million in net proceeds from the sale of such Trust Units were used to partially repay the advance made under the Current Bank Facility which had been used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan" and "Capitalization of the Trust".

ACQUISITION OF THE 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 "Description of the Trust – the 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 $26.1 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 475 (Mcf/d) net 33.

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 with an average working interest of 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 operates this area and has approximately a 99% working interest. Currently production is approximately 1,500 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 field contains 192 gross producing wells.

The wells produce from a thick lower Cretaceous channel sand that is underlain by an active aquifer. The majority of the wells are equipped with progressive cavity pumps to maximize fluid production. The Thompson Lake fluid production 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 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 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, currently producing approximately 800 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 assigned 1,036 MBOE of Established Reserves, before deduction of royalties, to this area. The field contains 54 gross producing wells.

The fluid production 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 Pipeline to the Hardisty terminal. Solution natural gas is conserved and processed at the Husky 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 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. Current production from this operated property is approximately 450 BOE/d of primarily 18° API oil, at a 98% water cut, from the Ellerslie "A" Pool and natural gas from the Glauconite "A" Pool. The McDaniel Report assigned 833 MBOE of Established Reserves, before deduction of royalties, to this area. The field contains 18 gross producing wells.

Production 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 are equipped with progressive cavity pumps to maximize fluid production. The Bellshill Lake fluid production 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 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 assigned 183 MBOE of Established Reserves, before deduction of royalties, to this area. The pool contains 5 gross producing wells.

The Metiskow fluid production 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 trucked from the battery 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 purchase of 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

Harvest has entered into physical swap and collar contracts with certain counter parties for certain of the production from the Initial Properties wherein it will deliver crude oil during 2003 and receive WTI pricing, as presented in the following table, less the appropriate quarterly and transportation adjustments.

Swaps:	Term	Price per Barrel
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
1,300 Bbls/d	January through March 2004	Cdn $24.33

Collars:	Term	Price per Barrel
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 $35.00 – 38.40
500 Bbls/d	October through December 2003	Cdn $35.00 – 37.35

The balance of production from the Initial Properties will be sold by way of evergreen contracts with 30 day cancellation notice provisions. David North, Thompson Lake and Bellshill Lake natural gas is sold on a spot market basis. See "Information Respecting the Corporation – Commodity Hedging".

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, well site restoration costs and salvage recovery, 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(1)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (6) (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (2)(7)(8)(11) Discounted at			
	Gross (4)	Net (3)	Gross (4)	Net (3)	0%	10%	15%	20%
Proved Reserves(4)								
Producing Reserves(4) (12)	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
Risked 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[(1) (9)]

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas [(6)] (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) [(2)(7)(8)(10)] Discounted at			
	Gross [(4)]	Net [(3)]	Gross [(4)]	Net [(3)]	0%	10%	15%	20%
Proved Reserves[(4)]								
Producing Reserves [(4) (12)]	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
Risked 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:

- (b) "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).
- (c) "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.
- (d) "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.
- (e) "Established Reserves" means the sum of 50% of Probable Reserves and 100% of Proved Reserves.
- (f) "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
- (g) "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 such 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, $5,000 and $5,000 of those capital expenditures estimated for the calendar years 2002, 2003, 2004 and 2005 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, $5,000 and $5,000 of those capital expenditures estimated for the calendar years 2002, 2003, 2004 and 2005 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/MMBTU

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	Heavy Crude Oil $/Bbl	Light Crude Oil WTI Cushing Oklahoma* $U.S./Bbl	Light Crude Oil Edmonton Par 40° API $/Bbl	Natural gas Liquids at Edmonton Propane $/Bbl	Natural gas Liquids at Edmonton Butane $/Bbl	Natural gas Liquids at Edmonton 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 $U.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, the date of the McDaniel Report.

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	7.0	20,765	47.7
Bellshill Lake	100	833	10.0	5,660	13.0
David North	100	1,036	10.0	14,664	33.7
Metiskow	100	183	7.5	1,500	3.5
Other	32	72	7.0	926	2.1
TOTAL (6) (7)	**99**	**4,573**	**8.3**	**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 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 September 30, 2002 in which the Corporation has an interest, and which are producing or which are considered by the Corporation to be capable of producing.

	Producing (4) (5)				Shut-in(1)			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)
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) "Shut-in" wells are wells which are not producing but which are considered by the Corporation to be capable of producing. 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.

(2) "Gross" wells are the total number of wells in which the Corporation has a working interest.

(3) "Net" wells means the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest acquired therein.

(4) Royalty interest wells have been assigned a net number of zero.

(5) Not all wells in which the Corporation has 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 and natural gas attributable to the Initial Properties, before deduction of royalties, for the periods indicated are summarized below.

	9 Month Period Ended September 30, 2002(1)	Year Ended December 31, (2)		
		2001	2000	1999
Crude oil and natural gas liquids (Mbbls)	679	1,065	1,238	1,249
Average daily production (Bbls/d)	2,488	2,917	3,393	3,423
Natural gas sales (Mmcf)	158	263	255	244
Average daily sales (Mcf/d)	578	719	700	668
Total oil equivalent (MBOE)	**706**	**1,109**	**1,281**	**1,290**
Average daily production (BOE/d)	**2,585**	**3,037**	**3,510**	**3,534**

Notes:

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

(2) Based on information provided to the Corporation by the Initial Properties Vendors and the Corporation's accounting records.

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. The Corporation has not participated in the drilling of any wells in respect of the Initial Properties since the acquisition of the Initial Properties.

	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)
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 and production 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.

	9 Month Period Ended September 30, 2002(1)	Year Ended December 31,(1)		
		2001	**2000**	**1999**
	($000's) (unaudited)	($000's)	($000's)	($000's)
Revenue:				
Petroleum and natural gas sales (2)	24,076	30,675	46,395	30,506
Royalties	2,114	2,792	4,407	2,985
Operating expenses	7,633	11,587	9,333	7,266
Operating Income	**14,329**	**16,296**	**32,655**	**20,255**

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 - $34.02/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 the Additional Properties Vendor 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 used approximately $22.9 million from the net proceeds of the Initial Public Offering to repay the Interim Loan (including accrued interest) and approximately $5.4 million from the net proceeds of the Initial Public 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" and "Capitalization of the Trust".

The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional $5.8 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 $5.8 million as an interim adjustment within 90 days and in any event not later than 180 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 the 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 major fields are Hayter and West Provost, both of which are operated by the Corporation. 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 assumed operatorship in this area. Currently production approximately 5,350 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 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 are equipped with progressive cavity pumps to maximize fluid production. The Hayter fluid production is gathered into one of two central batteries located at 8-35-40-1 W4M or 1-34-40-1 W4M in which the Corporation has a 95% working interest and is the operator. The batteries have a combined capacity of approximately 200,000 Bbls/d of fluid. Oil from the Hayter area is blended with condensate and shipped from the battery via the Gibson Provost pipeline to the Hardisty terminal. Solution natural gas is conserved and utilized as fuel gas at the batteries, with the remainder processed at the Husky North Hansman Gas Plant located at 8-14-39-03 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 assumed operatorship. Currently production is 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 to this area 952 MBOE of Established Reserves, before deduction of royalties. 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 acquired a 37.5% working interest. The battery has a capacity of approximately 115,000 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Provost pipeline to the Hardisty terminal. Solution and non-associated natural gas is conserved and processed at the Husky North, Hansman Lake Gas Plant at 8-14-39-03 W4M.

The 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 21,167 (7,427 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 $371,000 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:

Property	**Gross Area (Acres)**	**Net Area (Acres)**	**Assigned Value**
Hayter	8,142	3,342	$167,000
West Provost	13,025	4,085	$204,000
TOTAL	**21,167**	**7,427**	**$371,000**

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 the Additional Properties Vendor until December 31, 2003. To complete this contract the Corporation must 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 is 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 is effective until December 31, 2003. The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional $5.8 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 $5.8 million as an interim adjustment within 90 days and in any event not later than 180 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".

Produced solution natural gas 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, well site restoration costs, and salvage recovery, 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 (1)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas(2) (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (2)(3)(4) Discounted at			
	Gross (2)	Net (2)	Gross (2)	Net (2)	0%	10%	15%	20%
Proved Reserves(2)								
Producing Reserves (2) (6)	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 (1)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas(2) (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (2)(3)(5) Discounted at			
	Gross (2)	Net (2)	Gross (2)	Net (2)	0%	10%	15%	20%
Proved Reserves (2)								
Producing Reserves (2) (6)	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 (11) of "Initial Properties – Oil and Natural Gas Reserves".

(5) See Note (10) 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, the date of the McDaniel Report.

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)	Reserve Value (2)(3)(4)(5) %
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:

(a) 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;

(b) 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;

(c) the Hayter property has fluid handling limitations, which can be reduced through gathering and processing facility de-bottlenecking; and

(d) 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 September 30, 2002 in which the Corporation has an interest, and which are producing wells or which are considered by the Corporation to be capable of producing.

	Producing (4) (5)				Shut-in(1)			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)
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) "Shut-in Wells" means wells which are not producing but which are considered by the Corporation 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.
(2) "Gross Wells" means the total number of wells in which the Corporation acquired a working interest.
(3) "Net Wells" means the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest acquired therein.
(4) Royalty interest wells have been assigned a net number of zero.
(5) 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.

	9 Month Period Ended September 30, 2002 (2)	Year Ended December 31, (1)		
		2001	2000	1999
Crude oil and natural gas liquids (Mbbls)	1,955	2,873	2,404	2,077
Average daily production (Bbls/d)	7,160	7,872	6,587	5,689
Natural gas sales (Mmcf)	165	218	90	137
Average daily sales (Mcf/d)	605	596	246	374
Total oil equivalent (MBOE)	**1,982**	**2,909**	**2,419**	**2,099**
Average daily production (BOE/d)	**7,261**	**7,971**	**6,628**	**5,750**

Notes:

(1) Based on information provided to the Corporation by the Additional Properties Vendor.
(2) Based on information provided to the Corporation by the Additional Properties Vendor and the Corporation's accounting records.

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. The Corporation has not completed the drilling of any wells in respect of the Additional Properties since the acquisition of the Additional Properties. However, the Corporation as of February 4, 2003 has commenced a six well drilling program.

	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)
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 purchasers, and production 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.

	9 Month Period Ended September 30, 2002 (1)	Year Ended December 31, (1)		
		2001	2000	1999
	($000's) (unaudited)	($000's)	($000's)	($000's)
Revenue:				
Petroleum and natural gas sales (2)	55,460	57,615	72,026	42,693
Royalties	7,324	11,340	14,465	7,268
Operating expenses	12,666	12,832	8,800	7,453
Operating Income	**35,470**	**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 - $27.98/BOE; 2001 - $19.89/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 September 30, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at September 30, 2002 and for the nine months ended September 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. 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:** The Corporation, as operator of the Initial Properties and the Additional Properties, 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 Strategy".

(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 will 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, well site restoration costs and salvage recovery, 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 (1)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (2) Discounted at			
	Gross (2)	Net (2)	Gross (2)	Net (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 (1)

	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 (2)	Net (2)	Gross (2)	Net (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
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

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)
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	2.3	58	12	36	–	10	–	9
Total	**12,728.7**	**$ 324,003**	**$ 43,197**	**$ 135,441**	**$ 144**	**$ 145,510**	**$ 12,757**	**$ 132,752**

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.

	9 Month Period Ended September 30, 2002(2)(3)	Year Ended December 31, (1)(3) 2001	2000	1999
Crude oil and natural gas liquids (Mbbls)	2,634	3,938	3,642	3,326
Average daily production (Bbls/d)	9,649	10,789	9,980	9,112
Natural gas sales (Mmcf)	323	481	345	381
Average daily sales (Mcf/d)	1,182	1,315	946	1,042
Total oil equivalent (MBOE)	**2,688**	**4,018**	**3,700**	**3,389**
Average daily production (BOE/d)	**9,846**	**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) Based in part on information provided to the Corporation by the Initial Properties Vendors and the Additional Properties Vendor.
(3) 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.

	9 Month Period Ended September 30, 2002(1)	Year Ended December 31, (1)(2) 2001	2000	1999
	($000's) (unaudited)	($000's)	($000's)	($000's)
Revenue:				
Petroleum and natural gas sales (1)	79,536	88,290	118,422	73,199
Royalties	9,438	14,132	18,872	10,253
Operating expenses	20,299	24,419	18,133	14,719
Operating Income	**49,799**	**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 September 30, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust as at September 30, 2002 and for the nine months ended September 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

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 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;

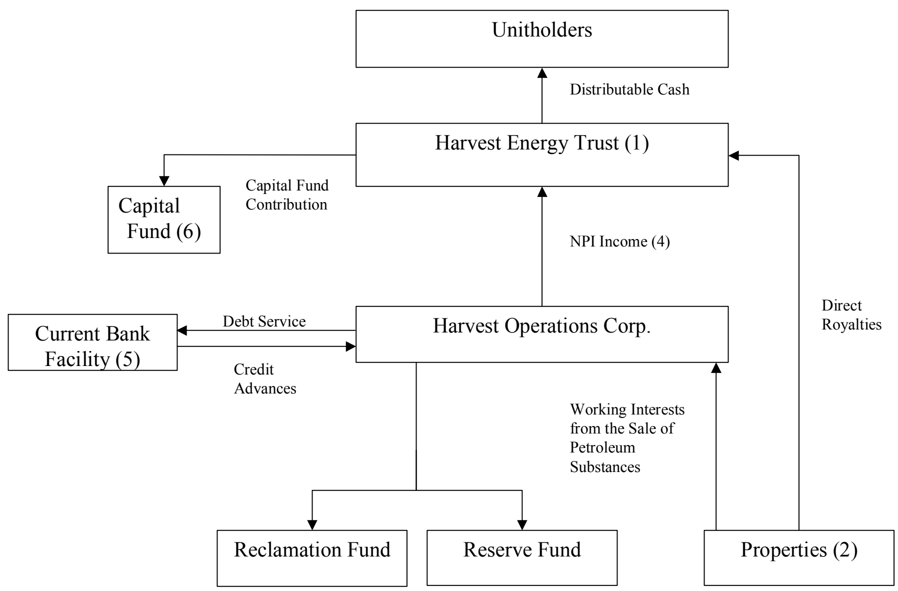
(d) disposing of any part of the Trust Fund, including, without limitation, any securities of the Corporation;

(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 the 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 – the NPI and Direct Royalties", "Acquisition of the 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 makes regular monthly payments to the Trust in the amount of the NPI Income. See "Description of the Trust – the NPI and Direct Royalties".

(5) The gross proceeds realized by the Trust from the issuance of the Special Warrants of $15,000,000 (before deducting the Underwriters' fee of $750,000 and the expenses in connection with the issuance of the Special Warrants and the qualification for distribution of the Qualified Units, estimated to be $200,000, which will be paid out of the general funds of the Trust) were used by the Trust to partially repay the advance made under the Current Bank Facility which was used previously to partially fund the Additional Properties Acquisition. See "Information Respecting the Corporation – Borrowing", "Capitalization of the Trust" and "Use of Proceeds".

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

The 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 the NPI Income is calculated, means 99% of production revenues from the Properties less 99% of the amount by which all the 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 the NPI Deductions and advances made pursuant to the Credit Facilities to fund the payment of the NPI Deductions. The 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 is 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 the 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), is used to defray certain expenses and capital expenditures of the Corporation.

Pursuant to the NPI Agreement, the Corporation is required to pay the Trust the 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 deducts, 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 also 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 such facilities. Any income from providing processing, gathering, disposal or treating services will not be included in the calculation of the NPI Income, but will be used to defray certain expenses and capital expenditures of the Corporation.

The Trust reimburses 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 is 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 further Direct Royalties and may acquire further Direct Royalties. Such Direct Royalties may consist of direct petroleum and natural gas royalty interests and may be acquired from time to time.

Deferred Purchase Price Obligation

Pursuant to the NPI 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 of any Properties held by the Corporation. The Trust is not obligated to pay an amount as a Deferred Purchase Price Obligation except to the extent the Trust has such proceeds available.

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

(a) if the designated expenditure is funded by issuing additional Trust Units, by the proceeds of dispositions of the Canadian resource property component of Properties, by the disposition of Direct Royalties or by the issuance of debt, it will not be a charge against the NPI Income, and therefore will not reduce payments of the 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 Properties acquired by the designated expenditure will be added to the revenues used to calculate the 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 and, pursuant to the NPI Agreement, 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, in consideration for the release of the NPI from such Properties, 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. Alternatively, 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 the 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 is 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 Tax 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 the NPI Deductions in calculating the NPI Income.

Reclamation Fund

The Corporation is 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 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 The NPI Income that is payable to the Trust. The Corporation currently estimates that the future environmental and reclamation obligations, after salvage recovery, in respect of the Initial Properties and the Additional Properties will aggregate approximately $4.3 million and $5.4 million, over the life of the Initial Properties and the Additional Properties respectively

Pursuant to the NPI Agreement, the Corporation is required to establish a reclamation fund, to which it makes annual contributions, 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 are credited to the NPI Deductions in calculating the 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, well site restoration costs and salvage recovery.**

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 is 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 the NPI Income payable to the Trust. See "Risk Factors – Environmental Concerns".

Cash Available For Distribution

Cash Available For Distribution consists of any amounts received by the Trust pursuant to the NPI and the Direct Royalties, any interest or other income from Permitted Investments, ARTC received by the Trust net of Non-Deductible Crown Royalties that are reimbursed by the Trust to the 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.

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

The actual amount of Cash Available For Distribution depends on, among other things, the quantity 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 also has 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 retains up to 50% of the Cash Available For Distribution in its Capital Fund to finance future acquisitions and development of Properties with the intent that it will be able to continue to provide or maintain the Cash Available For Distribution over a longer period of time than would otherwise be the case.

Distributable Cash

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

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

Income Tax Treatment

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

Board of Directors

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

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) the establishment of credit facilities, shall be made by the Board of Directors.

The Board of Directors holds meetings regularly to review the business and affairs of the Corporation and the Trust.

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, act as agent for the Trust, execute documents on behalf of the Trust and make executive decisions which conform to the general policies and the 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 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 potential future offerings of Units;

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

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

General and Administrative Costs are deducted from production revenues in computing the 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 are generally charged to the Trust by the Corporation based on direct costs incurred in fulfilling the obligations of the Corporation to the Trust pursuant to the Trust Indenture and the Administration Agreement. The Corporation is entitled to reimbursement for all of its direct and indirect expenses, costs and expenditures in connection with the creation, start-up, set-up and organization of the Trust and the transition from the 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 through 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. Upon closing of the Initial Public Offering, the Trust Debenture was settled through the issuance of 5,000,000 Trust Units to the Management Group. See "Capitalization of the Trust" and "Interests of Management and Others in Material Transactions".

Interim Loan

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

Upon closing of the Additional Properties Acquisition, the Trust had borrowed $23.2 million under the Interim Loan. 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 Trust used approximately $22.2 million from the net proceeds of the Initial Public Offering to repay the Interim Loan (including accrued interest) and approximately $4.2 million from the net proceeds of the Initial Public 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" and "Capitalization of the Trust".

Warrants

Pursuant to the Interim Loan, Caribou was granted 150,000 Warrants by the Trust to purchase an equivalent number of Trust Units at $1.00 each. The Warrants were issued as a commitment fee pursuant to the Interim Loan. M. Bruce Chernoff, a director of the Corporation, controls Caribou. The Warrants were exercised on January 23, 2003. See "Capitalization of the Trust" and "Interests of Management and Others in Material Transactions".

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 "Recent Developments", "Acquisition of the 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 37 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 targets 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 to other properties about which management of the Corporation considers it has particular expertise to effectively extract value; 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 serve as guidelines for the Corporation's 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 team of the Corporation possesses extensive experience in the operation of mature oil and natural gas fields. A key feature of the Corporation's strategy 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 interest 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 further 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 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:

Management of the Corporation believes that a key tactic in optimizing the value of the Properties is an active program of oil and natural gas field exploitation. In addition to their extensive operating experience, the Corporation's senior management team has 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 often 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 the 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 employs the following strategies to manage risk:

- commodity price risk is managed with a hedging program utilizing swaps, collars and options. See "Information Respecting the Corporation – Commodity Hedging". Contracts typically are entered into with large, stable counterparties and, to the extent possible, the Corporation avoids concentrating significant risk with any one counterparty;

- production volume risk is 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 is attempted to be minimized by acquiring additional Properties in mature, stable pools, with a history of predictable production levels;

- environmental, health and safety risk is 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 is 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 has implemented a distribution strategy whereby it may 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 the purchase of Properties, capital expenditures or other 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 the NPI Income and income from Direct Royalties for such 12 month period, unless specifically approved by the Board of Directors. The Corporation is entitled to grant security in priority to the NPI and the Trust is permitted to grant security on the NPI and Direct Royalties to secure the loan of funds directly to the Trust or secure guarantees granted by the Trust of indebtedness of the Corporation. The borrowings of the Trust require approval by the Board of Directors.

Debt Service Charges of the Corporation are deducted in computing the NPI Income and Debt Service Charges of the Trust are deducted in computing Cash Available For Distribution. Debt repayment by the Corporation is 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 U.S. $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 U.S. $38 million. The outstanding principal amount of the Current Bank Facility bears 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 0.5% (for Canadian dollar advances) (the "CDOR Rate") plus a margin of 1.125% per annum or 1.875% per annum respectively. For Eurodollar loans and advances by way of bankers' acceptances, the interest rate is based on the rates offered 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 to pay interest or principal on any indebtedness to the Trust, and therefore may 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 currently approximately $29.0 million. In addition, the Current Lender has issued approximately $6.6 million in letters of credit to third parties on behalf of the Corporation to secure services on the Properties. See "Properties".

Commodity Hedging

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

Swaps:	**Term**	**Price per Barrel**
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
1,300 Bbls/d	January through March 2004	U.S. $24.33
1,430 Bbls/d	April through June 2004	U.S. $22.93
1,200 Bbls/d	April through June 2004	U.S. $25.50
1,380 Bbls/d	July through September 2004	U.S. $22.70
500 Bbls/d	July through September 2004	U.S. $24.56
1,325 Bbls/d	October through December 2004	U.S. $22.54
500 Bbls/d	October through December 2004	U.S. $24.03
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:	Term	Price per Barrel
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 is 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.

The Corporation has also entered into the following electricity price hedging swap contracts with various counterparties:

	Term	Price per MegaWatt
5MW	January through December 2003	Cdn $46.30
5MW	January through December 2004	Cdn $46.00

Directors and Officers of the Corporation

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

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held [(1)]	Principal Occupation
John A. Brussa [(2)(4)] Calgary, Alberta	Director	235,000[(7)]	Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP (a law firm).
M. Bruce Chernoff[(3)(4)] Calgary, Alberta	Director, Chairman	4,143,776[(8)]	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.
Hank B. Swartout [(3)] Calgary, Alberta	Director	500,000	Chairman, President and Chief Executive Officer of Precision Drilling Corporation since July, 1987.

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held [1]	Principal Occupation
Verne G. Johnson [2][3] Calgary, Alberta	Director	20,000	President of KristErin Resources Inc., a private family company since January 2000; Senior Vice President, Funds Management of Enerplus Resources Group from 2000 to 2002; prior thereto, President and Chief Executive Officer of AltaQuest Energy Corporation from 1999 to 2000; prior thereto, President of Ziff Energy Group (an energy consulting company) from 1997 to 1999; prior thereto, President and Chief Executive Officer of ELAN Energy Inc. (a public oil and natural gas company) from 1989 to 1997.
Hector J. McFadyen [2][4] Calgary, Alberta	Director	20,000	Independent businessman and Director of Hunting PLC (a UK based public oil and natural gas company); formerly, President, Midstream Division, Alberta Energy Company Ltd. (a public oil and natural gas company). Director of Computershare Trust Company of Canada (a private Canadian company that manages the administration of shareholder and employee records from public and private companies throughout North America).
Jacob Roorda Calgary, Alberta	President	138,995[9]	Professional Engineer, President of the Corporation; from June 1999 to July 2002, Managing Director, Research Capital (a mid-sized investment banking dealer); from January 1996 to March 1999, Vice President, Corporate, Director and co-founder of PrimeWest Energy Trust ("PrimeWest") (a public energy trust); from May 1991 to January 1996, Manager, Business Development, Fletcher Challenge (a private oil and natural gas company).
J.A. Ralston Calgary, Alberta	Vice President, Operations	106,068	Vice President, Operations of the Corporation; from 1996 to 2002, Manager, Production of Penn West Petroleum ("PennWest") (a public oil and natural gas company).
David M. Fisher Calgary, Alberta	Vice President, Finance	47,500[10]	Vice President, Finance of the Corporation since October 2002; from September 1998 to October 2002, Director, Vice President, Finance and Chief Financial Officer of Integra Resources Ltd. ("Integra") (a private oil and natural gas corporation); from April 1995 to July 1998, Vice President, Finance and Chief Financial Officer of Canrise (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	No. of Trust Units Held (1)	Principal Occupation
David J. Rain Calgary, Alberta	Corporate Secretary	80,600	Chartered Accountant; Corporate Secretary of the Corporation; Vice President, Finance and Chief Financial Officer of Petrobank since October 2001; Vice President and Director of Caribou since April 2001; from April 2000 to September 2001, Director, Corporate Finance of Petrobank; from May 1997 to June 1999, Corporate Controller and Treasurer of Pacalta.

Notes:

(1) Represents all Trust Units held directly or indirectly or over which such person exercises control or direction. Based upon information provided by the director or officer to the Trust.
(2) Member of the Audit and Corporate Governance Committee.
(3) Member of the Reserves, Safety and Environment Committee.
(4) Member of the Compensation Committee.
(5) The Corporation does not have an executive committee.
(6) The terms of office of all of the directors will expire at the next annual shareholders' meeting of the Corporation.
(7) Does not include 2,750 Special Warrants held by Mr. Brussa.
(8) Does not include 167,750 Special Warrants held by Mr. Chernoff but does include 152,990 Trust Units held by Caribou Capital Corp., a company controlled by Mr. Chernoff.
(9) Does not include 10,000 Special Warrants held by Mr. Roorda.
(10) Does not include 9,250 Trust Units held in the name of Mr. Fisher's children but otherwise controlled by Mr. Fisher.

As at the date hereof, prior to giving effect to the exercise of the Special Warrants, the directors and officers of the Corporation and their associates and affiliates, as a group, hold, directly or indirectly, or exercise control or direction over, 5,143,933 Trust Units, representing 54% of the issued and outstanding Trust Units. After giving effect to the exercise of the Special Warrants, the directors and officers of the Corporation, and their associates and affiliates, as a group, will beneficially own, directly or indirectly, 5,324,433 Trust Units or 48% of the outstanding Trust Units.

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

Jacob Roorda, President

Mr. Roorda is a Professional Engineer and holds a Bachelor of Applied Science (Eng.) degree from 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 in July 1994 where he worked until June 2002. Since 1997, Mr. Ralston served as Production Manager, responsible for overseeing all of Penn West's 100,000 BOE/d production operations, 270 field staff and an annual budget of $200 million. Mr. Ralston was responsible for all areas of operations including engineering, exploitation, production optimization, capital management, planning, construction and budgeting.

David M. Fisher, Vice President, Finance

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

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

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

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

John A. Brussa, Director

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

M. Bruce Chernoff, Director and Chairman

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

Mr. Chernoff initiated the formation of Caribou, of which he is the President and a Director, in June 1999, to 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.

Hank B. Swartout, Director

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

Verne G. Johnson, Director

Mr. Johnson received a Bachelor of Science degree in Mechanical Engineering from the University of Manitoba in 1966. He immediately commenced employment with Imperial Oil Limited, which continued until 1981 (including two years with Exxon Corporation in New York from 1977 to 1979). In 1981, Mr. Johnson joined Liberty Petroleum Ltd. as President and Chief Executive Officer. In 1982, he joined Roxy Petroleum Ltd. as Vice President, Production, remaining until 1987 when he joined Paragon Petroleum Ltd. as President. In 1989, Mr. Johnson joined ELAN Energy Inc. (then Lasmo Canada Inc.) as

President and a Director. Following the sale of ELAN in 1997, he became President of Ziff Energy Group until 1999, then President of AltaQuest Energy Corporation and he then joined the Enerplus Resources Group in 2000, becoming Senior Vice President of Funds Management. In February 2002, he departed from the Enerplus Resources Group and remains as President of his private family company, KristErin Resources Inc.

Hector J. McFadyen, Director

Mr. McFadyen holds a 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 its Economics Department.

Mr. McFadyen began work for Alberta Energy Company Ltd. ("**AEC**"), now 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 from 1981, and retiring from Encana in June 2002.

Mr. McFadyen developed a number of significant business units within AEC, developing experience in a broad range of businesses and disciplines. Such experience included project development and investments across North America, Latin America, Asia and Europe. At AEC, Mr. McFadyen served as a member of the senior executive team involved in recommending and implementing the strategic plan for the company. As President of the Forest Products Division 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". Mr. McFadyen was also recently appointed to the Board of Directors of Computershare Trust Company of Canada, a private Canadian company that manages the administration of shareholder and employee records for public and private companies throughout North America.

David J. Rain, Corporate Secretary

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

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

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
	E3 Energy Ltd. (formerly Mill City International Inc.)	Director	10 2002	**Present**
	Edge Energy Inc. (formerly Alberta Oil & Gas Ltd.)	Director	01 1998	08 2000
	Endev Energy Inc.(formerly Net Shepherd Inc.)	Director	01 2002	**Present**
	Energy Savings Income Fund	Director	02 2001	**Present**
	FET Resources Inc. (formerly Storm Energy Inc., formerly Dancap Resources)	Director	10 1997	**Present**
	Focus Energy Trust (formerly Storm Energy Inc.)	Director	10 1997	**Present**
	Harvest Energy Ltd.	Director	10 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
	Inter Pipeline Fund (formerly Koch Pipelines Canada, L.P.)	Director	11 2002	**Present**
	Magin Energy Inc.	Director	06 1996	06 2001
	Meota Resources Corp.	Director	12 1997	10 2002
	NCE Energy Corporation	Director	11 1996	07 2001
	Navigo Energy Inc. (formerly Ventus Energy Ltd.)	Director	08 1998	09 2001
	Penn West Petroleum Ltd.	Director	04 1995	**Present**
	Petrobank Energy and Resources Ltd.	Director	03 2000	**Present**
	Progress Energy Ltd.	Director	11 2000	**Present**
	Rio Alto Exploration Ltd.	Director	06 1992	07 2002
	Rio Alto Resources International Inc.	Director	07 2002	**Present**
	Southpoint Resources Ltd.	Director	08 2002	**Present**

Name	Name of Reporting Issuer	Position	From	To
	Tanganyika Oil Company Ltd.	Director	06 1997	09 2001
M. Bruce Chernoff	Westpoint Energy Inc. (formerly Slade Energy Inc.)	Director	01 1998	05 2000
	Brooklyn Energy Corporation	Director	11 2001	**Present**
	Canada Talon	Director	05 1197	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
Hank B. Swartout	Precision Drilling Corporation	Chairman, President and Chief Executive Officer	07 1987	**Present**
Verne Johnson	AltaQuest 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 Partners L.P.	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**
	Computershare Trust Company of Canada	Director	11 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	PrimeWest Energy Inc.	Vice President & Director	10 1996	04 1999
David Fisher	Canrise Resources Ltd.	V.P. Finance & CFO	04 1995	07 1998

COMPENSATION OF EXECUTIVE OFFICERS AND DIRECTORS

Compensation of Named Executive Officers

The Corporation currently has three executive officers who receive annual salaries of $125,000, $100,000 and $100,000, respectively. Such officers have received and 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 following table sets forth information concerning the compensation paid to the current President of the Corporation for the fiscal year ended December 31, 2002. No officers of the Corporation received compensation in excess of $100,000 during the most recently completed financial year of the Corporation.

		Annual Compensation				
Name and Principal Position	**Year**	**Salary ($)**	**Bonus ($)**	**Other Annual Compensation ($)**	**Securities Under Options Granted (#)**	**All Other Compensation ($)**
Jacob Roorda (1) President	2002	50,000	Nil	6,699	175,000	Nil

Notes:
(1) Mr. Roorda has been the President of the Corporation since August 1, 2002.
(2) The Corporation did not commence active business until July, 2002. Prior to Mr. Roorda's appointment, Mr. Chernoff was the President of the Corporation. Mr. Chernoff did not receive any compensation, including options, for acting as President of the Corporation.

Unit Options

The following table sets forth the details with respect to all options granted to Mr. Roorda during the fiscal year ended December 31, 2002.

Name	Securities Under Option	% of Total Options Granted to Employees in Financial Year	Exercise or Base Price ($/Security)	Market Value of Securities Underlying Options on the Date of Grant ($/Security)	Expiration Date
Jacob Roorda	175,000	22.9	8.00	8.00	November 25, 2007

The following table sets forth with respect to Mr. Roorda and the number of options exercised and the number of unexercised unit options and the value of in-the-money unit options based upon the closing price of the Trust Units of $9.50 on December 31, 2002.

Name	Securities acquired on exercise (#)	Aggregate value realized ($)	Unexercised unit options at year-end (#) exercisable/unexercisable	Value of unexercised in-the-money unit options at year-end ($) exercisable/unexercisable
Jacob Roorda	-	-	-/175,000	-/297,500

Employment Agreements

The Corporation has not entered into employment agreements with Mr. Roorda or any other of its officers or senior employees. However, the Corporation intends to enter into employment agreements with each of these officers, and any additional senior officers, and such agreements are expected to contain industry standard severance and change of control provisions.

Directors

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

INDEBTEDNESS OF DIRECTORS AND OFFICERS

At no time since incorporation has there been any indebtedness of any director or officer of the Corporation, or any associate of any such director or officer, to the Corporation or the Trust or to any other entity which is, or at any time since the beginning of the most recently completed financial period has been, the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Corporation or 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, one hundred common shares of the Corporation are outstanding. Such shares are held by the Trustee for and on behalf of the Trust. The voting of such shares is governed by the provisions of the Trust Indenture and the Trust is not entitled, without the direction of Unitholders, to exercise its rights as a shareholder of the Corporation except as permitted by the Trust Indenture. See "The Trust Indenture – Exercise of Voting Rights Attached to Shares of the Corporation".

THE TRUST INDENTURE

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

Trust Units

An unlimited number of Trust Units may be created and issued pursuant to the Trust Indenture. Each Trust Unit entitles the holder thereof to one vote at any meeting of the holders of Trust Units and represents an equal undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding-up of the Trust. All Trust Units outstanding from time to time shall be entitled to equal shares of any distributions by the Trust, and in the event of termination or winding-up of the Trust, in any net assets of the Trust. All Trust Units shall rank among themselves equally and rateably without discrimination, preference or priority. Each Trust Unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the Trust Units held by such holder (see "The Trust Indenture 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 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 are deducted in computing the Cash Available For Distribution.

Redemption Right

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to the Trust of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem Trust Units by the Trust, the holder thereof shall only be entitled to receive a price per Trust Unit (the "Market Redemption Price") equal to the lesser of: (i) 90% of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to the Trust for redemption; and (ii) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption.

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

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

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

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

It is anticipated that this Redemption Right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Redemption Notes which may be distributed in specie to Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such Redemption Notes. Redemption Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Non-Resident Unitholders

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

Meetings of Unitholders

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

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

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

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

Exercise of Voting Rights Attached to Shares of the Corporation

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

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

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

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

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

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

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

Trustee

Valiant Trust Company is the trustee of the Trust. All of the administrative and management powers of the Trustee relating to the Trust and the operations of the Trust have been delegated to the Corporation pursuant to the Trust Indenture and the Administration Agreement. See "Description of the Trust – 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.

Termination of the Trust

Unitholders may vote to terminate the Trust at any meeting of the Unitholders duly called for that purpose, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20% of the outstanding Trust Units; (b) a quorum of 50% of the issued and outstanding Trust Units is present in person or by proxy; and (c) the termination must be approved by Special Resolution of Unitholders.

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

Reporting to Unitholders

The consolidated financial statements of the Trust will be audited annually by an independent recognized firm of chartered accountants. The audited consolidated financial statements of the Trust, together with the report of such chartered accountants, will be mailed by the Corporation to Unitholders and the unaudited interim consolidated financial statements of the Trust will be mailed to Unitholders within the periods prescribed by securities legislation. The year end of the Trust shall be December 31. The Trust will be subject to the continuous disclosure obligations under all applicable securities legislation.

TRUST UNIT INCENTIVE PLAN

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 total number of Trust Units issuable under the Unit Incentive Plan is 875,000 Trust Units.

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

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

The following table sets forth information with respect to the Incentive Rights outstanding under the Unit Incentive Plan on the date hereof.

Group	Date Incentive Rights Granted	Trust Units Under Option	Grant Price	Closing Price on Day Prior to Grant	Expiry Date	Market Value of Incentive Right [(1)]
Executive Officers (4)	November 25, 2002	475,000	$8.00	$8.00	November 25, 2007	$1,923,750
	February 14, 2003	9,500	$10.75	$10.75	February 14, 2008	$8,550
Directors (4)	November 25, 2002	75,000	$8.00	$8.00	November 25, 2005	$303,750
	February 14, 2003	25,000	$10.75	$10.75	February 14, 2008	$22,500
Employees and Consultants (12)	November 25, 2002	237,500	$8.00	$8.00	November 25, 2005	$961,875
	January 24, 2003	32,500	$10.21	$10.21	January 24, 2008	$53,300

Note:

(1) Based on the difference between the closing price of $11.45 per Trust Unit on the TSX on March 6, 2003 and the grant price of the Incentive Right less distributions per Trust Unit paid after the date the Incentive Right was granted multiplied by the number of Trust Units under the Incentive Right.

DRIP PLAN

The Trust has received all applicable regulatory approvals and has implemented a Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP Plan"). **The DRIP Plan is not available to Unitholders who are residents of the United States.** The DRIP Plan provides eligible holders of Trust Units the means of accumulating additional Trust Units by reinvesting any Distributable Cash received. At the discretion of the Corporation, Trust Units will either be acquired at prevailing market rates (not exceeding 115% of the volume weighted average trading price of the Trust Units on the TSX for the 10 trading days immediately preceding the date the Trust Units are purchased) or issued from treasury at 95% of the market price of the Trust Units (calculated as the weighted average trading price of the Trust Units on the TSX for the period commencing on the second Business Day following the distribution record date and ending on the second Business Day immediately prior to the distribution payment date on which at least a board lot of Trust Units is traded). Participants in the DRIP Plan are also permitted to purchase additional Trust Units at 100% of the market price (as described above) of the Trust Units by investing additional sums to a maximum of $5,000 per month and a minimum of $1,000 per remittance; provided that the total number of Trust Units that may be issued each fiscal year pursuant to optional cash payments is restricted to not more than 2% of the number of issued and outstanding Trust Units at the commencement of that year. On February 17, 2003, 79,208 Trust Units were issued from treasury for proceeds of $794,650 due to DRIP Plan participation associated with the January distribution.

CAPITALIZATION OF THE TRUST

The following table sets forth the consolidated capitalization of the Trust as at the dates noted.

Designation	Authorized	Outstanding as at September 30, 2002	Outstanding as at September 30, 2002 after giving effect to the Issuance of Special Warrants	Outstanding as at September 30, 2002 after giving effect to the exercise of Special Warrants
Current Bank Facility (1)(2)(3)	U.S. $60,000,000	$Nil	$34,857,043	$34,857,043
Trust Debenture (4)	$5,000,000	$5,000,000	$Nil	$Nil
Interim Loan (5)	$43,000,000	$12,923,000	$Nil	$Nil
Trust Units (4)(6)(7)	Unlimited	$100 (one hundred Trust Units)	$39,650,000 (9,462,500 Trust Units)	$54,650,000 (10,962,500 Trust Units)
Special Warrants	$15, 000,000	$Nil	$15,000,000 (1,500,000 warrants)	$Nil

Notes:

(1) Effective September 30, 2002, the Corporation had a credit facility with an initial borrowing base of $18 million with a Canadian chartered bank. At September 30 2002, the Corporation had drawn $13.1 million on this credit facility. 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 $29.0 million. In addition the Current Lender has issued to third parties approximately $6.6 million in letters of credit. The initial borrowing base under the Current Bank Facility is $U.S. $38 million. See "Initial Properties", "Additional Properties" and "Information Respecting the Corporation – Borrowing".

(3) The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional $5.8 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 $5.8 million as an interim adjustment within 90 days or in any event not later than 180 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 the arbitration process established in the Additional Properties Agreement. See "Risk Factors".

(4) The Trust Debenture was issued effective as of August 15, 2002 by the Trust in exchange for $5,000,000 cash. The Trust Debenture bore interest at 2.0%, was unsecured and was due December 31, 2002. Principal and outstanding interest under the Trust Debenture could be settled in either cash or Trust Units, at the option of the holder. If settled in Trust Units, the dollar amount outstanding would be converted to Trust Units at a fixed price of $1.00 per Trust Unit. Outstanding amounts due under the Trust Debenture became due and payable on the earlier of the maturity date and the date on which the Trust qualified as a mutual fund trust through the listing of the Trust Units on a recognized Canadian stock exchange. The Trust Debenture was settled through the issuance of 5,000,000 Trust Units on completion of the Initial Public Offering.

(5) Upon closing of the Additional Properties Acquisition, the Trust had borrowed $22.2 million under the Interim Loan which bore interest at 20% per annum and was provided by Caribou, which is controlled by M. Bruce Chernoff, a director 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. Approximately $22.3 million from the net proceeds of the Initial Public Offering was used to repay the Interim Loan (including accrued interest). See "Additional Properties", "Information Respecting the Corporation – Borrowing" and "Description of the Trust – Interim Loan".

(6) The initial 100 Trust Units issued to settle the Trust were cancelled at the closing of the Initial Public Offering. Pursuant to the Interim Loan, the Trust issued 150,000 Warrants to Caribou to purchase an equivalent number of Trust Units for $1.00 each. These Warrants were exercised on January 23, 2003. See "Description of the Trust – Warrants" and "Interests of Management and Others in Material Transactions".

(7) Does not include 79,208 Trust Units issued from treasury on February 17, 2003, for proceeds of $794,650 due to DRIP Plan participation associated with the January distribution. See "DRIP Plan".

PRICE RANGE AND TRADING VOLUME

The Trust Units have been listed and posted for trading on the TSX under the trading symbol "HTE" since December 5, 2002. The following table sets forth the simple average of the reported high and low sales prices and the trading volumes for the Trust Units for the periods indicated as reported by the TSX.

	High	Low	Volume
December 5, 2003 to December 31, 2003	9.50	8.25	561,757
January 1, 2003 to January 31, 2003	11.00	9.45	396,022
February 1, 2003 to February 28, 2003	10.95	10.38	185,001
March 1, 2003 to March 6, 2003	11.75	10.85	87,872

Note:

(1) On January 16, 2003, being the day of negotiation of the issue price of the Special Warrants, the closing price of the Trust Units on the TSX was $10.75. On March 6, 2003, being the last day on which the Trust Units traded prior to the date of this prospectus, the closing price of the Trust Units on the TSX was $11.45.

PRIOR SALES

On July 10, 2002, the Trust issued 100 Trust Units to the original settlor of the Trust for $100 to facilitate its organization. On December 5, 2002, 3,750,000 Trust Units were issued at a price of $8.00 per Trust Unit pursuant to the closing of the Initial Public Offering and 5,000,000 Trust Units were issued at a price of $1.00 per Trust Unit on the settlement of the Trust Debenture. On December 17, 2002, 562,500 Trust Units were issued at a price of $8.00 per Trust Unit pursuant to the exercise of an over-allotment option granted to the Underwriters in connection with the Initial Public Offering. On January 23, 2003, 150,000 Trust Units were issued to Caribou at a price of $1.00 per Trust Unit pursuant to the exercise of the Warrant. On February 17, 2003, 79,208 Trust Units were issued from treasury for proceeds of $794,650 at a price of $10.0325 per Trust Unit due to DRIP Plan participation associated with the January distribution.

RECORD OF CASH DISTRIBUTIONS

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

2003	Distribution Per Trust Unit
January (1)	$0.20
February(2)	$0.20

Notes:

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

(2) The Trust announced on February 18, 2002 that the next monthly cash distribution of $0.20 per Trust Unit will be paid on March 17, 2003 to Unitholders of record on February 28, 2003.

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

(4) Pursuant to the Special Warrant Indenture, holders of Special Warrants are entitled to monthly cash and certain other distributions as if they were holders of Units.

ESCROWED SECURITIES

In connection with the completion of the Initial Public Offering, certain members of the Management Group holding an aggregate $4,777,500 principal amount of the Management Group Debentures (which were settled with 4,777,500 Trust Units representing approximately 49.7% of the currently outstanding Trust Units, approximately 42.9% after giving effect to the exercise of the Special Warrants) executed an undertaking in favour of the Underwriters not to offer or sell, agree to offer or sell, or enter into an arrangement to offer or sell any Trust Units or other securities of the Trust or the Corporation, or securities convertible into, exchangeable for, or otherwise exercisable to acquire any securities of the Trust or the Corporation then held by such holder or such holder's spouse, directly or indirectly, at any time until November 28, 2004. See "Interests of Management and Others in Material Transactions".

PLAN OF DISTRIBUTION

This prospectus is being filed in the Filing Provinces to qualify the distribution of the Qualified Units to be issued upon the exercise of the Special Warrants. All of the issued and outstanding Special Warrants are fully-paid and non-assessable and the Qualified Units, or the Trust Units issuable upon the exercise of the Special Warrants in the event that the Special Warrants are exercised prior to the issuance of a Final MRRS decision document, will, when issued, be fully-paid and non-assessable.

On the Closing Date, the Trust completed a private placement of 1,500,000 Special Warrants pursuant to prospectus exemptions under applicable securities legislation through the Underwriters in accordance with the Underwriting Agreement. Pursuant to the Underwriting Agreement, the Underwriters agreed to act as, and the Trust appointed the Underwriters as, sole and exclusive agents of the Trust to offer the Special Warrants in the Filing Provinces on a private placement basis at a price of $10.00 per Special Warrant. The Underwriters sold the Special Warrants as agents and presently do not hold any Special Warrants. Pursuant to the Underwriting Agreement, the Trust has paid a fee of $750,000 to the Underwriters. The Underwriters will receive no other fees in connection with the distribution of the Qualified Units under this prospectus. The offering price of the Special Warrants was determined by negotiation between Harvest, on behalf of the Trust, and the Underwriters.

The Trust or the Corporation shall, without prior written consent of FirstEnergy Capital Corp. on behalf of the Underwriters, which consent shall not be unreasonably withheld, create, authorize, issue or sell or announce its intention to so create, authorize, issue or sell any Trust Units or other securities of the Trust, rights to purchase such Trust Units, or other securities of the Trust, or any securities convertible into or exercisable or exchangeable for such Trust Units, or other securities of the Trust, or agree to any of the foregoing, prior to June 5, 2003, except for (i) options granted under the Trust's Unit Incentive Plan and Trust Units issued pursuant to the exercise of such options; and (ii) Trust Units issued pursuant to the DRIP Plan.

The Special Warrants were issued pursuant to the Special Warrant Indenture. Since the date of issuance, no Special Warrants have been exercised. Each Special Warrant entitles the holder to acquire, subject to adjustment, at no additional cost, one Qualified Unit of the Trust at any time until 5:00 p.m. (Calgary time) on the earlier of: (i) five (5) Business Days after the Final Receipt Date; and (ii) the first anniversary of the Closing Date.

In the event that the Trust sets a Record Date in respect of or pays a distribution or sets a Record Date in respect of or makes any other distribution in cash or property or securities of the Trust to all or substantially all of the holders of Trust Units of record on a date after February 4, 2003 (the "Effective Date") and prior to the exercise or deemed exercise of the Special Warrants, the Trust agrees that it will pay the same amount of such distribution or make the same distribution of cash, property or securities to the Warrant Trustee on behalf of entitled holders of Special Warrants, on such date as if the holders of such Special Warrants on such date were the holders of the number of Trust Units which the holders of Special Warrants are entitled to receive upon exercise of the Special Warrants and such payments or other distributions shall be held and dealt with by the Warrant Trustee in accordance with the Special Warrant Indenture.

In the event that a Final MRRS decision document is not obtained by the Trust on or prior to the Qualification Deadline on behalf of the Canadian securities regulatory authority in each of the Filing Provinces, then each holder of Special Warrants in the Filing Provinces on whose behalf a Final MRRS decision document has not been obtained (or, if a Final MRRS decision document has not been obtained on behalf of the Province of Alberta, all holders wherever resident) shall be entitled after the Qualification Deadline to receive on the exercise or deemed exercise of the Special Warrants an additional 0.09 of a Trust Unit for each such Special Warrant so exercised without additional payment. This prospectus also qualifies the distribution of the additional 0.09 of a Trust Unit per Special Warrant in the event that such units are issued. Special Warrants not previously exercised by the holders thereof shall be deemed to be exercised immediately prior to the Expiry Time without further action on the part of the holder. The Trust will continue to use its best efforts to obtain a Final MRRS decision document on behalf of the Canadian securities regulatory authority in each Filing Province where a Final MRRS decision document is not obtained on or before the Qualification Deadline until February 4, 2004.

Any Trust Units issued in exchange for Special Warrants exercised on or after the Closing Date and prior to the Final Receipt Date will be subject to relevant hold periods under applicable securities legislation.

Holders of Special Warrants who wish to exercise the Special Warrants held by them in order to acquire Trust Units hereunder should complete the exercise form attached to the Special Warrant certificate and deliver the certificates and the executed exercise forms to the Warrant Trustee at its principal office in Calgary, Alberta. The Special Warrants represented by a Special Warrant certificate shall be deemed to be surrendered only upon personal delivery of the certificate or, if sent by mail or other means of transmission, upon actual receipt thereof by the Warrant Trustee at the office referred to above.

The Special Warrant Indenture provides that in the event of certain alterations of the Trust Units, including any subdivision, consolidation or reclassification, and in the event of any form of reorganization of the Trust or the Corporation, including any amalgamation, merger or arrangement, an adjustment shall be made to the terms of the Special Warrants such that the holders shall, upon exercise of the Special Warrants following the occurrence of any of those events, be entitled to receive the same number and kind of securities that they would have been entitled to receive had they exercised their Special Warrants prior to the occurrence of those events. The holding of Special Warrants does not constitute the holder thereof a unitholder of the Trust or entitle the holder to any right or interest in respect thereof except as expressly provided in the Special Warrant Indenture.

The Special Warrant Indenture provides that all holders of Special Warrant certificates shall be bound by any resolution passed at a meeting of the holders of Special Warrants held in accordance with the provisions of the Special Warrant Indenture and resolutions signed by the holders of Special Warrants entitled to acquire a specified majority of the Trust Units which may be acquired pursuant to all the then outstanding Special Warrant certificates.

The TSX has conditionally approved the listing of the Qualified Units subject to the Trust fulfilling all of the requirements of such exchange.

The Qualified Units have not been and will not be registered under the U.S. Securities Act. Accordingly, the Qualified Units may not be offered or sold within the United States except in certain transactions exempt from the registration requirements of the U.S. Securities Act. In addition, until 40 days after the commencement of this offering, any offer or sale of the Qualified Units within the United States by any dealer (whether or not participating in this offering) may violate the registration requirements of the U.S. Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A of the U.S. Securities Act.

USE OF PROCEEDS

The Trust raised gross proceeds from the issuance of the Special Warrants of $15 million (before deducting the Underwriters' Fee of $750,000 and the expenses of the issuance of the Special Warrants and the qualification for distribution of the Qualified Units, estimated to be $200,000, which will be paid out of the general funds of the Trust). The Trust will not receive any cash proceeds upon the exercise of the Special Warrants. All of the net proceeds from the financing were used to partially repay outstanding balances under the Current Bank Facility, which was used to partially fund the Additional Properties Acquisition and for working capital. See "Additional Properties".

PRINCIPAL UNITHOLDERS

To the best of the knowledge of the directors and officers of the Corporation, the only person that owns, directly or indirectly, or exercises control or direction over Trust Units carrying more than 10% of the votes attached to all of the issued and outstanding Trust Units is:

		Number of Trust Units Owned		**Percentage of Trust Units**	
Name and Address of Shareholder	**Type of Ownership**	**Before Exercise of Special Warrants**	**After Exercise of Special Warrants**	**Before Exercise of Special Warrants**	**After Exercise of Special Warrants**
M. Bruce Chernoff	Direct and Beneficial	4,143,776[(1)]	4,311,526[(1)]	43.4%	39.0%

Note:

(1) Includes 152,990 Trust Units owned by Caribou Capital Corp., a company controlled by Mr. Chernoff.

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 "Counsel") the following is a summary of the principal Canadian federal income tax consequences generally applicable to persons who have acquired Special Warrants pursuant to the Special Warrant Indenture and who will acquire and dispose of Trust Units issuable on the exercise of the Special Warrants and who, for the purposes of the Tax Act and at all relevant times are resident in Canada, hold such Special Warrants and Trust Units as capital property, and deal at arm's length with the Trust. The Special Warrants and Trust Units will generally be considered capital property to the holder thereof unless either the holder holds the Special Warrants and the Trust Units in the course of carrying on a business or the holder has acquired the Special Warrants and Trust Units in a transaction or transactions considered to be, individually or collectively, an adventure in the nature of trade.

This summary is based upon the current provisions of the Tax Act, Counsel's understanding of the current published administrative practices of the CCRA, and proposed amendments to the Tax Act publicly announced by the Minister of Finance (Canada) prior to the date hereof (the "Proposed Amendments"). This summary assumes that the Proposed Amendments will be enacted as proposed, but does not take into account or anticipate any other changes in law, whether by way of judicial, legislative or governmental decision or action, nor does it take into account any provincial, territorial or foreign income tax considerations. No assurances can be given that the Proposed Amendments will be enacted as proposed, if at all, or that legislative, judicial or administrative changes will not modify or change the statements expressed herein. No application has been made to the CCRA for an advance income tax ruling with respect to this offering.

This summary does not apply to holders that are "financial institutions" within the meaning of the "mark-to-market" rules contained in the Tax Act, or who, at any time, have an "at-risk adjustment" as defined in the Tax Act.

The Canadian federal income tax consequences of a particular holder will vary depending on a number of factors. **The following discussion of the income tax consequences is of a general nature only and is not exhaustive of all the income tax consequences and is not intended to constitute income tax advice to any particular holder. Accordingly, holders should consult their own income tax advisors with respect to the Canadian federal income tax consequences which will result from holding Special Warrants and acquiring, holding and disposing of Trust Units issuable on the exercise of the Special Warrants.**

Exercise or Disposition of Special Warrants

An original holder of a Special Warrant will have a cost for tax purposes equal to the amount paid for such Special Warrant upon subscription (plus any related acquisition costs). A holder will not realize a gain or loss upon the exercise or deemed exercise of Special Warrants to receive Trust Units. The cost for tax purposes of Trust Units acquired pursuant to the exercise of the Special Warrants will generally be equal to the tax cost of such Special Warrants. In computing the adjusted cost base of a holder's Trust Units acquired pursuant to the exercise of the Special Warrants, the cost of such Trust Units must be averaged with the cost of any other Trust Units held as capital property at that time.

A disposition or deemed disposition of Special Warrants (other than on the exercise of such Special Warrants) will result in the realization of a capital gain (or capital loss) in the taxation year of the disposition to the extent the proceeds of disposition exceed (or are exceeded by) the aggregate of the adjusted cost base of such Special Warrants, net of any reasonable disposition costs.

Distributions on Special Warrants

Although the matter is not entirely clear, distributions made to holders of Special Warrants upon exercise thereof will be required to be included in the income of the particular holder of Special Warrants for the purposes of the Act.

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.

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 is a Trust Unit will include all amounts paid or payable by the Unitholder for such 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 described above. 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 in that year, and the Trust Units will have a nil adjusted cost base to commence the subsequent year.

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 that 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 (or, if the Proposed Amendments become law, that becomes receivable) 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 "Canadian Federal Tax Considerations 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 "Canadian Federal Income Tax Considerations – Income from Trust Units". 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 Tax 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.**

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 or trusts 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 balance between supply and demand. 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 m^3 /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 m^3 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 m^3, and 25%, at prices above $210 per m^3 . 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 properties 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 with the interests of the Corporation and the Trust. No assurances can be given that opportunities identified by such board members will be provided to the Corporation and the Trust.

LEGAL MATTERS

Certain legal matters in connection with the distribution of the Qualified Units issuable on the exercise or deemed exercise of the Special Warrants 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" 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.

INTEREST OF EXPERTS

None of Burnet, Duckworth & Palmer LLP, Blake, Cassels & Graydon LLP, KPMG LLP or McDaniel has received or will receive a direct or indirect interest in the property of the Corporation or the Trust or of any associate or affiliate of the Corporation or the Trust in connection with the offering of the Special Warrants or the distribution of the Qualified Units.

The opinions contained under "Canadian Federal Income Tax Considerations" 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 of February 12, 2003, the partners and associates of Burnet, Duckworth & Palmer LLP as a group, will beneficially own, directly or indirectly, less than 5% of the outstanding Trust Units and the partners and associates of Blake, Cassels & Graydon LLP, as a group, will beneficially own, directly or indirectly, less than 1% of the outstanding Trust Units.

Further, as at the date hereof, the partners of KPMG LLP, as a group, did not beneficially own, directly or indirectly, any of the Trust Units of the Corporation. In addition, except for Mr. Brussa, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associates or affiliates of the Corporation.

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".

The following table sets forth the number of Trust Units owned, directly or indirectly, by Mr. Chernoff and Mr. Bennett:

		Number of Trust Units Owned		**Percentage of Trust Units**	
Name and Address of Unitholder	**Type of Ownership**	**Before Exercise of Special Warrants**	**After Exercise of Special Warrants (1)**	**Before Exercise of Special Warrants**	**After Exercise of Special Warrants (1)**
M. Bruce Chernoff	Direct and Beneficial	4,143,776(2)(3)	4,311,526(2)(3)	43.4%	39.0%
Kevin Bennett	Direct and Beneficial	700,000(4)	700,000(4)	7.3%	6.3%

Notes:
(1) Assumes the exercise of all outstanding Special Warrants.
(2) Includes 152,990 Trust Units owned by Caribou Capital Corp., a company controlled by Mr. Chernoff.
(3) Does not include Trust Units held by Mr. Chernoff's spouse.
(4) Does not include Trust Units held by Mr. Bennett's spouse.

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 "Recent Developments".

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 physical 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 hedging contracts with Gibson in the future.

The Trust issued the Trust Debenture and incurred the Interim Loan pursuant to financing the acquisition of the Initial Properties and the Additional Properties Acquisition. The Interim Loan was provided by Caribou, a company controlled by M. Bruce Chernoff, a director of the Corporation, which bore interest at 20% per annum and was due on or before July 31, 2003. The Interim Loan was secured by all of the assets of the Trust, including the NPI, but was not secured by the Properties of the Corporation. All amounts outstanding under the Interim Loan were repaid with net proceeds from the Initial Public Offering. See "Capitalization of the Trust" and "Description of the Trust – Interim Loan".

Upon completion of the Initial Public Offering, the Trust Debenture was settled with the issuance of 5,000,000 Trust Units and such Trust Units were distributed to the Management Group in settlement of the Management Group Debentures. In addition, on January 23, 2003, the Warrants, issued to Caribou pursuant to the Interim Loan, were exercised for 150,000 Trust Units. Caribou, which is controlled by M. Bruce Chernoff, a director of the Corporation, held the Warrants. See "Capitalization of the Trust" and "Description of the Trust – Warrants".

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

Mr. Brussa, a director of the Corporation is a partner of Burnet, Duckworth & Palmer LLP which firm receives fees for legal services provided to the Corporation and the Trust.

The following directors and/or officers of Harvest acquired the number of Special Warrants set forth opposite each of their names:

Name	Position with Harvest	Number of Special Warrants
M. Bruce Chernoff	Director, Chairman	167,750
Jacob Roorda	President	10,000
John Brussa	Director	2,750

RISK FACTORS

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

Public and Insider Ownership

As at the date hereof, prior to giving effect to the exercise of the Special Warrants, the directors and officers of the Corporation and their associates and affiliates, as a group, hold, directly or indirectly, or exercise control or direction over, 5,143,933 Trust Units, representing 54% of the issued and outstanding Trust Units. After giving effect to the exercise of the Special Warrants, the directors and officers of the Corporation, and their associates and affiliates, as a group, will beneficially own, directly or indirectly, 5,324,433 Trust Units or 48% of the outstanding Trust Units.

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

Dilution

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Harvest Board may determine. In addition, the Trust may issue additional Trust Units from time to time pursuant to the 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 the 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 $5.8 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 $5.8 million as an interim adjustment within 90 days and in any event not later than 180 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 the 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 operator of the Initial Properties or that the Corporation will operate the Additional Properties or any other Properties it may acquire.

Although satisfactory title reviews will generally be conducted on the Properties in accordance with industry standards, such reviews do not guarantee or certify that a defect in title may not arise to defeat the claim of the Corporation to certain Properties. A reduction of 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 differ from the estimates prepared by McDaniel.

Environmental Concerns

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or the issuance of clean up orders in respect of the Corporation or the Properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on the Corporation. See "Industry Conditions – Environmental Regulation". Although the Corporation will establish a Reclamation Fund for the purpose of funding its estimated future environmental and reclamation obligations based on its knowledge, there can be no assurance that the Corporation will be able to satisfy its actual 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.

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

Debt Service

The Corporation's indebtedness under the Current Bank Facility is currently approximately $29.0 million. In addition, the Current Lender has issued letters of credit to third parties in approximately $6.6 million in letters of credit on behalf of the Corporation to secure services on the Properties. See "Properties".

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. The Current Bank Facility is due on the earlier of April 30, 2004 or upon an event of default.

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 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 Subordination Agreement may restrict the ability of the Corporation to pay the NPI to the Trust or pay interest or principal on any indebtedness to the Trust, and therefore may limit 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 the incurring of indebtedness, the 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 service debt before payment of the NPI and cash distributions. 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 counterparty risk.

Debt Repayment

The Corporation and the Trust are permitted to borrow funds to finance the purchase of Properties, capital expenditures, or other financial obligations in respect of the Properties or for working capital purposes. Borrowings of the Corporation to fund the purchase of Canadian resource properties may be repaid with funds received from the Trust pursuant to the Deferred Purchase Price Obligation. Debt Service Charges of the Corporation will be deducted in computing the NPI Income and Debt Service Charges of the Trust will be deducted in computing Cash Available For Distribution. Variations in interest rates could result in significant changes in the amount required to be applied to debt service before payment of the NPI and Cash Available For Distribution. To the extent that 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" 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 retains 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 the 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 the Trust Units. Investors who are not willing to rely on the management of the Corporation should not invest in the Trust Units.

Depletion of Reserves (Sustainability)

The Trust has certain unique attributes which differentiate it from other oil and natural gas industry participants. Cash Available For Distribution in respect of Properties, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. The Trust and the Corporation will not be reinvesting cash flow in the same manner as other industry participants. Accordingly, absent additional capital investment in Properties through the use of the Capital Fund or otherwise, initial production levels and reserves attributable to the Properties will decline.

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

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

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

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

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 made only limited 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 oil and gas prices or increases in differentials could have a material adverse effect on the Trust's operations, financial condition and the level of funds available for the development of its oil and natural gas reserves. The Corporation may manage the risk associated with changes in commodity prices and foreign exchange rates by entering, or causing the Trust to enter, from time to time, into crude oil and natural gas price hedges and foreign exchange contracts. To the extent that the Corporation or the Trust engages in risk management activities related to commodity prices and foreign exchange rates, it will be subject to counterparty risk. In addition, commodity hedge contracts may require, from time to time, margin payments to be made which could impact negatively on the Trust's ability to make distributions to Unitholders. The Corporation must also meet certain ongoing hedging covenants under 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 such processing yields less valuable products compared to refining light oil; accordingly, producers of heavy oil or medium oil receive lower wellhead prices. The differential between light oil and heavy oil or medium oil has fluctuated widely during recent years and when considered with the fluctuating prices of light oil, substantially increases the volatility of prices for heavy oil and medium oil. Any increase in the differentials could result in lower prices being received for Petroleum Substances and could have a material adverse effect on the Trust's operations, financial condition and the level of funds available for the development of its oil and natural gas reserves. Volatility in the differential is a result of an availability of supply, seasonal demand, pipeline constraints and conversion capacity of refineries, which are beyond the control of the Trust or the Corporation.

Competition

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

Potential Conflicts of Interest

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

Nature of Trust Units

Securities such as the Trust Units are hybrids in that they share certain attributes common to both equity securities and debt instruments. Trust Units are dissimilar to debt instruments in that there is no principal amount owing to Unitholders. The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in the Corporation. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The Trust's sole assets will be Permitted Investments, the NPI, the Direct Royalties and related contractual rights. The market price per Trust Unit will be a function of anticipated Cash Available For Distribution, the value of the Initial Properties acquired by the Corporation, the value of the Additional Properties 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 that liability, such liability shall be enforceable only against, and shall be satisfied only out of, the Trust Fund, and the Trust (to the extent of the Trust Fund) is liable to, and shall indemnify and save harmless any Unitholder against any costs, damages, liabilities, expenses, charges or losses suffered by any Unitholder from or arising as a result of such Unitholder not having any such limited liability.

The Trust Indenture also provides that all contracts signed by or on behalf of the Trust, whether by the Corporation, the Trustee, or otherwise, must (except as the Trustee or the Corporation may otherwise expressly agree with respect to their own personal liability) contain a provision to the effect that such obligation will not be binding upon Unitholders personally. The principal investment of the Trust is the NPI Agreement which contains such a 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.

Net Asset Value

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

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 in effect as of the date hereof entered into by the Trust or by the Corporation during the past two years, other than during the ordinary course of business, are as follows:

1. Trust Indenture referred to under "The Trust Indenture";
2. The NPI Agreement referred to under "Description of the Trust – the 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. the Direct Royalties Sale Agreements referred to under "Initial Properties" and "Additional Properties";
7. the Sale Agreement referred to under "Initial Properties";

8. the Additional Properties Agreement referred to under "Additional Properties";

9. the management undertakings referred to under "Interests of Insiders and Others in Material Transactions";

10. the Underwriting Agreement referred to under "Plan of Distribution"; and

11. the Special Warrant Indenture referred to under "Plan of Distribution".

During the period of distribution of the Trust Units, copies of the foregoing documents may 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 as 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.

CONTRACTUAL RIGHT OF ACTION FOR RESCISSION

In the event that a holder of a Special Warrant, who acquires a Qualified Unit upon the exercise of a Special Warrant as provided for in this prospectus, is or becomes entitled under applicable legislation to the remedy of rescission by reason of this prospectus, or any amendment thereto, containing a misrepresentation, the holder shall be entitled to rescission not only of the holder's exercise of its Special Warrant, but also of the private placement transaction pursuant to which the Special Warrant was initially acquired and shall be entitled, in connection with such rescission, to a full refund of all consideration paid to the Trust on the acquisition of the Special Warrant. In the event that such holder is a permitted assignee of the interest of the original Special Warrant subscriber, such permitted assignee shall be entitled to exercise the rights of rescission and refund described herein as if the permitted assignee was the original subscriber. The foregoing is in addition to any other right or remedy available to a holder of the Special Warrant under Section 203 of the *Securities Act* (Alberta), Section 131 of the *Securities Act* (British Columbia), Section 130 of the *Securities Act* (Ontario), similar sections of other applicable securities legislation or otherwise at law.

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. Consolidated Financial Statements of Harvest Energy Trust – Period from formation on July 10, 2002 to September 30, 2002.

4. Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at September 30, 2002 and for the nine months ended September 30, 2002 and year ended December 31, 2001.

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Schedule of Revenue and Expenses for the

INITIAL PROPERTIES

Acquired from Devon Canada Corporation

Years ended December 31, 2001, 2000 and 1999

AUDITORS' REPORT

To the board of directors of Harvest Operations Corp.

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

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

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

(Signed) KPMG LLP

Chartered Accountants

Calgary, Canada
September 18, 2002

INITIAL PROPERTIES

Schedule of Revenue and Expenses for the Initial Properties

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

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

1. **Basis of presentation:**

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

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

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

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

2. **Significant accounting policies:**

   (a) Revenue:

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

   (b) Royalties:

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

   (c) Operating expenses:

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

Schedule of Revenue and Expenses for the

ADDITIONAL PROPERTIES

Acquired from Anadarko Canada Corporation

Years ended December 31, 2001, 2000 and 1999

AUDITORS' REPORT

To the board of directors of Harvest Operations Corp.

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

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

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

(Signed) KPMG LLP

Chartered Accountants

Calgary, Canada
September 18, 2002

ADDITIONAL PROPERTIES

Schedule of Revenue and Expenses for the Additional Properties

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

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

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)

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1. Basis of presentation:

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

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

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

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

2. Significant accounting policies:

(a) Revenue:

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

(b) Royalties:

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

(c) Operating expenses:

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

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Consolidated Financial Statements of

HARVEST ENERGY TRUST

Period from formation on July 10, 2002 to September 30, 2002

AUDITORS' REPORT TO THE TRUSTEE OF HARVEST ENERGY TRUST AND 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
March 7, 2003

HARVEST ENERGY TRUST

Consolidated Balance Sheets

	September 30, 2002 (unaudited)	July 10, 2002 (audited)
Assets		
Current assets:		
Cash and short-term investments	$ 14,533	$ 100
Accounts receivable	4,531,419	–
Prepaid expenses	171,404	–
	4,717,356	100
Capital assets (note 3)	24,931,475	–
Deferred financing charges, net of amortization	338,000	–
Property purchase deposit	5,000,000	–
	$34,986,831	$ 100
Liabilities and Unitholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 1,709,438	$ –
Large corporation taxes payable	27,900	–
	1,737,338	–
Long-term debt (note 4)	30,981,220	–
Future income taxes (note 7)	256,000	–
Site restoration and reclamation provision (note 3)	329,000	–
	33,303,558	–
Unitholders' equity:		
Capital contributions (note 5)	100	100
Accumulated income	1,683,173	–
Accumulated cash distributions	–	–
	1,683,273	100
Subsequent events (notes 4 and 10)		
	$34,986,831	$ 100

See accompanying notes to consolidated financial statements.

Approved by the Board:

(Signed) "John A. Brussa" Director

(Signed) "Verne G. Johnson" Director

HARVEST ENERGY TRUST
Consolidated Statement of Income and Accumulated Income

For the period from formation on July 10, 2002 to September 30, 2002

	(unaudited)
Revenues:	
Oil and gas sales	$ 7,705,578
Royalty income	41,387
Royalties	(767,199)
	6,979,766
Expenses:	
Operating	2,167,791
General and administrative	196,380
Interest and amortization of financing charges	859,522
Site restoration	329,000
Depletion, depreciation and amortization	1,460,000
	5,012,693
Income before taxes	1,967,073
Taxes:	
Large corporation taxes	27,900
Future income taxes (note 7)	256,000
	283,900
Net income for the period, being accumulated income at September 30, 2002	$ 1,683,173

See accompanying notes to consolidated financial statements.

HARVEST ENERGY TRUST

Consolidated Statement of Cash

For the period from formation on July 10, 2002 to September 30, 2002

	(unaudited)
Cash provided by (used in)	
Operations	
Net income for the period	$ 1,683,173
Add items not involving cash:	
Depletion, depreciation and amortization	1,460,000
Site restoration	329,000
Future income taxes	256,000
Amortization of financing charges	45,242
Accrued interest expense	660,620
	4,434,035
Change in non-cash working capital (note 9)	(3,188,723)
	1,245,312
Financing:	
Bank borrowings	13,065,000
Loans from Caribou Capital Corp.	12,255,600
Debenture borrowings	5,000,000
Debt placement fees	(383,242)
	29,937,358
Investing:	
Property purchase deposit	(5,000,000)
Capital expenditures	(284,156)
Properties acquisition (note 3)	(26,107,319)
Change in non-cash working capital (note 9)	223,238
	(31,168,237)
Increase in cash and short-term investments	14,433
Cash and short-term investments, beginning of period	100
Cash and short-term investments, end of period	$ 14,533
Cash interest payment	$ 153,660
Cash taxes payment	–

See accompanying notes to consolidated financial statements.

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1. Structure of the trust:

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

The beneficiaries of the Trust are the holders of Trust Units. Upon completion of the initial public offering, the Trust will make monthly distributions of its distributable cash to unitholders of record on the last day of each calendar month. The amount of the distributions per Trust Unit are equal to the pro rata share of the net income of the Trust (including direct royalties received, net profit interests in the oil and gas properties and crown charges that are not deductible for income tax purposes of Harvest), dividends of Harvest, Alberta Royalty Tax Credits received less expenses (including interest and debt repayments) and net realized capital gains of the Trust less an appropriate working capital reserve.

2. Significant accounting policies:

The management of Harvest prepares the financial statements following Canadian generally accepted accounting principles. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Consolidation:

These consolidated financial statements include the accounts of the Trust and Harvest. All inter-entity transactions and balances have been eliminated upon consolidation.

(b) Capital assets:

The Trust follows the full cost method of accounting. All costs of acquiring oil and gas properties and related exploration and development costs, including overhead charges directly related to these activities, are capitalized and accumulated in one cost center. Maintenance and repairs are charged against earnings. Renewals and enhancements that extend the economic life of the capital assets are capitalized.

Gains and losses are not recognized on disposition of oil and gas properties unless that disposition would alter the rate of depletion by 20% or more.

Ceiling test

The Trust places a limit on the aggregate cost of capital assets, which may be carried forward for depletion against net revenues of future periods (the ceiling test). The ceiling test is a cost recovery test whereby: capitalized costs, less accumulated depletion and site restoration and the lower of cost and market value of unproved land, are limited to an amount equal to estimated undiscounted future net revenues from proved reserves, less general and administrative expenses, site restoration, management fees, future financing costs and applicable income taxes. Costs and prices at the balance sheet date are used. Any costs carried on the balance sheet in excess of the ceiling test limitation are charged to income.

Site restoration and reclamation provision

The Trust provides for the cost of future site restoration and reclamation, based on estimates by management, using the unit-of-production method. Actual site restoration costs are charged against the accumulated liability.

Depletion, depreciation and amortization

Provision for depletion and depreciation is calculated on the unit-of-production method, based on proved reserves before royalties. Independent petroleum engineers estimate reserves. Reserves are converted to equivalent units on the basis of approximate relative energy content.

Depreciation and amortization of office furniture and equipment is provided for a rates ranging from 10% to 33% per annum.

(c) Joint venture accounting:

Harvest conducts substantially all of its oil and gas production activities through joint ventures, and the accounts reflect only their proportionate interest in such activities.

(d) Income taxes:

The Trust is a taxable entity under the *Income Tax Act (Canada)* and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust plans to distribute all of its taxable income to the unitholders and meets the requirements of the *Income Tax Act (Canada)* applicable to a Trust, the Trust makes provision for income taxes on the taxes payable basis.

Harvest follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in its financial statements and its respective tax base, using enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets and liabilities.

(e) Unit-based compensation:

The Trust uses the intrinsic value based method of accounting for the unit-based incentive plan described in note 5. The Trust does not recognize compensation expense on the issuance of rights to employees and directors, as the exercise price of rights equals the market price on the day of the grant. Under the terms of the plan, the exercise price of rights granted may be reduced in future periods. As the amount of this reduction cannot be reasonably estimated, it is not possible to determine a fair value for rights granted. Accordingly, the Trust does not recognize an expense on the issuance of rights to non-employees and compensation costs for pro forma disclosure purposes are determined based on the excess of the unit price over the exercise price at the date of the financial statements.

(f) Deferred financing charges:

Deferred financing charges relate to costs incurred on the issuance of debt and are being amortized on a straight-line basis over the life of the bank loans.

(g) Financial instruments:

Harvest uses financial instruments to manage its exposure to fluctuations in commodity prices, foreign currency exchange rates, and interest rates. Harvest does not use financial instruments for speculative trading purposes and, accordingly, they are accounted for as hedges. Gains and losses on hedging activity are reflected in revenue, or in the case of interest rate hedges, in interest charges, at the time of sale of the related hedge production, or when the monthly exchange contracts expire.

(h) Cash and short term investments:

Short-term investments with maturities less than three months are considered to be cash equivalents and are recorded at cost, which approximate market value.

(i) Foreign Currency Translation:

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in income in the period in which they arise.

3. Capital assets:

	Cost	Accumulated depreciation	Net book value
Oil and gas properties	$ 19,357,283	$ (1,071,000)	$18,286,283
Production facilities and equipment	6,970,000	(377,000)	6,593,000
Office furniture and equipment	64,192	(12,000)	52,192
	$ 26,391,475	$ (1,460,000)	$24,931,475

On July 10, 2002 Harvest acquired the Initial Properties for $26,107,319.

General and administrative costs of $60,918 have been capitalized during the period ended September 30, 2002.

All costs are subject to depletion and depreciation at September 30, 2002. In addition, future development costs of $240,000 are included in depletion and depreciation calculations at September 30, 2002.

Site restoration involves the surface clean up and reclamation of well site and field production facilities. In addition, certain plant facilities will require decommissioning, which involves dismantlement of facilities as well as the decontamination and reclamation of these lands. Total estimated future costs are approximately $5,292,000, of which $329,000 has been accrued to September 30, 2002. The board of directors of Harvest has established a fund to ensure that cash is available to carry out the future site restoration and reclamation work. Beginning in 2003, contributions are to be made to this fund at an amount yet to be determined. Contributions will be deducted from cash available for distribution to unitholders.

4. Long-term debt:

Revolving bank credit facility		$13,065,000
Loan from Caribou Capital Corp:		
Principal	$12,255,600	
Accrued interest	647,741	12,903,341
Debenture:		
Principal	$ 5,000,000	
Accrued interest	12,879	5,012,879
		$30,981,220

Revolving bank credit facility:

At September 30, 2002, Harvest had 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 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 facility was to revolve until May 31, 2003 at which time it 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 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, including a requirement that Harvest maintain price hedging agreements for not less than 67% of its expected production, 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.

Loan from Caribou Capital Corp.:

In July 2002, the Trust entered into agreements providing for up to $43 million of loans from Caribou Capital Corp. To September 30, 2002, Caribou Capital Corp. had advanced $12,255,600 to partially finance the acquisition of the Initial Properties. The loan bears interest at a rate of 20% per annum, is unsecured and matures on July 31, 2003.

Trust Debenture:

In August 2002, the Trust issued a debenture for proceeds of $5,000,000. The 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 unit.

5. Unitholders' equity:

(a) Authorized:

The authorized capital consists of an unlimited number of Trust Units.

Each Trust Unit is entitled to a beneficiary interest in any distribution of the Trust and in any net assets in the event of termination or wind-up. Trust Units are redeemable at any time at the option of the holder. The redemption price is equal to the lesser of (i) 90% of the average market price of the Trust Units during a 10 day period commencing immediately after the date on which the units are tendered for redemption, or (ii) the closing market price on the date that the units are tendered for redemption date. The total amount payable by the Trust in respect of redemptions in any calendar month and in any preceding calendar month shall not exceed $100,000. To the extent that a unitholder is entitled to a redemption payment, it will be satisfied by a cash payment from the Trust or by the Trust distributing a pro-rata number of Harvest notes or distributing its own notes.

(b) Issued:

	Units	Amount
Issued for cash on formation, being the balance outstanding at September 30, 2002	100	$ 100

(c) Incentive plan:

A Trust Unit incentive plan has been established. Under the plan, the Trust is authorized to grant non-transferable rights to purchase Trust Units to directors, officers, consultants, employees and other service providers to an aggregate of 875,000 Trust Units. The initial exercise price of rights granted under the plan is equal to the closing market price on the date immediately prior to the date the rights are granted and the maximum term of each right is not to exceed five years. The exercise price of the rights may be adjusted downwards from time to time based upon the cash distributions made on the Trust Units in excess of a minimum distribution rate.

(d) Rights to purchase units:

Reference is made to notes 4 and 6.

6. Related party transactions:

Caribou Capital Corp., a company controlled by a director of Harvest, advanced $12,255,600 during the period ended September 30, 2002 (see note 4). Caribou Capital Corp. was granted warrants to purchase 150,000 Trust Units at $1.00 per unit as a fee for providing the credit facility. The warrants expire on July 31, 2003. Caribou Capital Corp. earned $647,450 of interest on the loan during the period ended September 30, 2002.

Certain officers and directors of the Harvest and their associates provided $3,837,500 of the $5,000,000 of funds obtained pursuant to the debenture (see note 4). The officers and directors earned $9,884 of interest on the debenture during the period ended September 30, 2002.

7. Income taxes:

The provisions for future income taxes varies from the amount that would be computed by applying the combined Canadian federal and provincial income tax rates to the reported income before taxes:

Income before taxes	$ 1,967,073
Computed income tax expense at the statutory rate of 41.6%	$ 818,300
Increase (decrease) resulting from:	
Non-deductible crown royalties and other payments	141,000
Federal resource allowance	(225,900)
Amounts included in trust income	(477,400)
Future income taxes	$ 256,000

The net future income tax liability is comprised of:

Future tax liabilities:	
Capital assets in excess of tax value	$ 393,000
Future tax assets:	
Site restoration and reclamation provision	(137,000)
Net future tax liability	$ 256,000

The capital assets owned by the Trust have a tax basis of approximately $11,300,000 available for future use as a deduction from taxable income. The book value of the assets in the Trust approximate the tax basis at September 30, 2002.

Net assets of Harvest with a book value of $18,640,000 have a tax basis of $18,025,000 available for future use as deductions from taxable income. Included in the tax basis are non-capital losses carryforwards of $218,000, which expire in 2009.

8. Financial instrument and other disclosures:

(a) Commodity risk management:

The bank loan agreement requires Harvest to maintain hedging arrangements in effect with respect to not less than 67% of its expected production. Harvest uses oil sales contracts and derivative financial instruments to comply with this requirement.

A summary of the oil sales contracts with price swap or collar features at September 30, 2002 that have fixed future sales prices are as follows:

Period	Type	Volume	Price
4th Quarter 2002	swap	1200 bbls per day	$39.31
4th Quarter 2002	collar	500 bbls per day	$36.50 - $41.67
1st Quarter 2003	swap	1000 bbls per day	$38.30
1st Quarter 2003	collar	500 bbls per day	$35.00 - $41.30
2nd Quarter 2003	swap	1000 bbls per day	$37.59
2nd Quarter 2003	collar	500 bbls per day	$35.00 – $39.60
3rd Quarter 2003	swap	1000 bbls per day	$37.10
3rd Quarter 2003	collar	500 bbls per day	$35.40 - $38.40
4th Quarter 2004	swap	1000 bbls per day	$36.63
4th Quarter 2004	collar	500 bbls per day	$35.50 - $37.35

A summary of the financial instruments at September 30, 2002 to fix oil prices on future sales is as follows:

Period	Volume	Price
1st Quarter 2003	200 bbls/d	$U.S. 24.95
2nd Quarter 2003	200 bbls/d	$U.S. 24.39
1st Quarter 2004	1510 bbls/d	$U.S. 23.23
2nd Quarter 2004	1430 bbls/d	$U.S. 22.93
3rd Quarter 2004	1380 bbls/d	$U.S. 22.70
4th Quarter 2004	1325 bbls/d	$U.S. 22.54
1st Quarter 2005	1100 bbls/d	$U.S. 22.38
2nd Quarter 2005	1030 bbls/d	$U.S. 22.18

Based upon quoted rates for similar contracts, at September 30, 2002 a payment of $881,000 would be required to terminate the financial instruments.

Harvest has entered into electricity purchase price swap contracts to fix the cost of future electricity usage. These contracts fix the price on up to 5 mega watt-hours per day at $46.30 and $46.00 per mega watt-hour for the year ended December 31, 2003 and 2004, respectively. Based upon posted rates, at September 30, 2002, a payment of $17,000 would have been required to terminate these contracts.

(b) Interest rate risk:

Harvest is exposed to interest rate risk on its bank loan.

(c) Credit risk:

Substantially all of the accounts receivable are due from customers in the oil and gas industry and are subject to normal industry credit risks. The carrying value of accounts receivable reflects management's assessment of the associated credit risks.

(d) Fair values of financial instruments:

Financial instruments carried on the balance sheet consist mainly of accounts receivable, accounts payable and accrued liabilities, taxes payable and long-term debt. At September 30, 2002, there were no significant differences between the carrying value of these financial instruments and their estimated fair value.

9. Change in non-cash working capital:

Changes in non-cash working capital items:	
Accounts receivable	$ (4,531,419)
Prepaid expenses	(171,404)
Accounts payable and accrued liabilities	1,709,438
Large corporation taxes payable	27,900
	$ (2,965,485)
Changes relating to investing activities	$ 223,238
Changes relating to operations	(3,188,723)
	$ (2,965,485)

10. Subsequent events:

On November 15, 2002, Harvest acquired the Additional Properties for approximately $53.2 million. This acquisition was financed by $38.2 million of bank borrowings, $10 million of loans from Caribou Capital Corp., and the application of the $5.0 million property purchase deposit. In conjunction with this acquisition, Harvest entered into a sales agreement to deliver 6,000 bbls per day of Lloydminster crude oil until December 31, 2003 at a price between U.S.$22.63 and U.S.$25.48 per bbl less a fixed price differential of U.S.$ 8.233 per bbl. To meet the contract requirements, Harvest will have to purchase up to 1,000 bbl. per day of diluents to blend with its production.

On closing, the vendor indicated its intent to charge Harvest an additional $5.8 million for the properties. Management believes that such amount is not owing to the vendor and accordingly, the additional amount has not been included in the cost of the purchase. This dispute is expected to be resolved through an arbitration process and any amount paid and not recoverable will be recorded as capital assets upon settlement.

On December 5, 2002, the Trust issued 3,750,000 Trust Units for $27.6 million, net of a 6% underwriters' fee and $600,000 of issue costs. The net proceeds were used to fully repay the loan from Caribou Capital Corp. and partially repay the bank loan. In conjunction with this initial public offering, the Trust granted the underwriters an option to purchase up to an additional 562,500 Trust Units at a price of $8.00 per unit. On December 17, 2002, the underwriters exercised the option; the net proceeds were used to partially repay the bank loan.

Upon completion of the initial public offering the Trust paid the debenture principal and interest payable thereon by the issuance of 5,000,000 Trust Units and a cash payment of $34,829.

On December 17, 2002, the Trust announced a cash distribution of $0.20 per Trust Unit to the unitholders of record on December 31, 2002. The distribution was paid on January 15, 2003.

On January 15, 2003, the Trust announced a cash distribution of $0.20 per Trust Unit to the unitholders of record on January 31, 2003. The distribution was paid on February 17, 2003. On February 17, 2003, 79,208 Trust Units were issued for $794,650 on the reinvestment of distributions pursuant to the Distribution Reinvestment and Optional Unit Purchase Plan.

On January 24, 2003, 150,000 Trust Units were issued to Caribou Capital Corp. on the exercise of a warrant. The $150,000 in proceeds was added to working capital.

On February 4, 2003, pursuant to an underwriting agreement the Trust issued 1,500,000 special warrants for $14,050,000, net of a 5% underwriters' fee and $200,000 of issue costs. The warrants are exercisable into 1,500,000 on Trust Units at no additional cost. The net proceeds were added to working capital and used to partially repay the bank loan.

On February 18, 2003, the Trust announced a cash distribution of $0.20 per trust unit to the unitholders of record on February 28, 2003. The distribution is payable by the Trust on March 17, 2003.

kpmg

Unaudited Pro Forma Consolidated Financial Statements of

HARVEST ENERGY TRUST

As at and for the nine months ended September 30, 2002

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 September 30, 2002 and the unaudited pro forma consolidated statement of income for the nine months ended September 30, 2002. These pro forma consolidated financial statements have been prepared for inclusion in the prospectus dated March 7, 2003.

In our opinion, the unaudited pro forma consolidated balance sheet as at September 30, 2002 and the unaudited pro forma consolidated statement of income for the nine months ended September 30, 2002 have been properly compiled to give effect to the assumptions and adjustments described in the notes thereto.

(Signed) KPMG LLP

Chartered Accountants

Calgary, Canada
March 7, 2003

HARVEST ENERGY TRUST

Pro Forma Consolidated Balance Sheet

As at September 30, 2002
(Unaudited)

	Actual Consolidated	Adjustments	Notes	Pro Forma Consolidated
Assets				
Current assets:				
Cash and short-term investments	$ 14,533	$ 137,122	2(d), 2(e),2(g)	$ 151,655
Accounts receivable	4,531,419	–		4,531,419
Prepaid expenses	171,404	–		171,404
	4,717,356	137,122		4,854,478
Capital assets	24,931,475	57,468,700	2(a)	82,400,175
Deferred financing charges	338,000	1,962,000	2(b)	2,300,000
Property purchase deposit	5,000,000	(5,000,000)	2(a)	–
	$ 34,986,831	$ 54,567,822		$ 89,554,653
Liabilities and Unitholders' Equity				
Current liabilities:				
Accounts payable and accrued liabilities	$ 1,709,438	$ –	2(e)	$ 1,709,438
Large corporation taxes payable	27,900	–		27,900
	1,737,338	–		1,737,338
Long-term debt	30,981,220	3,875,823	2(a),2(b),2(c),2(d),2(e),2(f),2(h)	34,857,043
Future income taxes	256,000	(142,000)	2(b)	114,000
Site restoration and reclamation provision	329,000	–		329,000
	33,303,558	3,733,823		37,037,381
Unitholders' equity:				
Capital contributions	100	51,029,999	2(d), 2(e), 2(f), 2(g), 2(h)	51,030,099
Accumulated income	1,683,173	(196,000)	2(b)	1,487,173
Accumulated cash distributions	–	–		–
	1,683,273	50,833,999		52,517,272
	$ 34,986,831	$ 54,567,822		$ 89,554,653

See accompanying notes to pro forma consolidated financial statements.

HARVEST ENERGY TRUST

Pro Forma Consolidated Statement of Income

Nine months ended September 30, 2002
(Unaudited)

	Initial Properties	Additional Properties	Adjustments	Notes	Pro Forma Consolidated
Revenue:					
Petroleum and natural gas sales	$24,075,804	$55,459,785	$ –		$79,535,589
Royalties	(2,114,180)	(7,323,940)	–		(9,438,120)
	21,961,624	48,135,845	–		70,097,469
Expenses:					
Operating	7,632,482	12,665,536		–	20,298,018
General and administrative	–	–	1,586,209	3(d)	1,586,209
Interest and amortization of deferred financing charges	–	–	3,000,000	3(c)	3,000,000
Site restoration	–	–	1,986,000	3(b)	1,986,000
Depletion, depreciation and amortization	–	–	18,400,000	3(a)	18,400,000
	7,632,482	12,665,536	24,972,209		45,270,227
Income (loss) before taxes	14,329,142	35,470,309	(24,972,209)		24,827,242
Taxes:					
Large corporation taxes	–	–	42,200	3(e)	42,200
Net income (loss)	$ 14,329,142	$35,470,309	$ (25,014,409)		$24,785,042
Net income per unit:				3(f)	
Basic					$ 2.26
Diluted					$ 2.23

See accompanying notes to pro forma consolidated financial statements.

1. Basis of presentation:

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

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

The unaudited pro forma consolidated balance sheet as at September 30, 2002 has been prepared from the unaudited balance sheet of the Trust as at September 30, 2002. The unaudited pro forma consolidated statement of earnings for the nine months ended September 30, 2002 has been based on:

- the unaudited statement of income of the Trust for the period from formation on July 10, 2002 to September 30, 2002;
- an unaudited schedule of revenue and expenses for the Initial Properties for the period from July 1, 2002 to July 10, 2002;
- the unaudited schedule of revenue and expenses for the Initial Properties for the six-month period ended June 30, 2002;
- the unaudited schedule of revenue and expenses for the Additional Properties for the nine-month period ended September 30, 2002.

In the opinion of management, the pro forma consolidated financial statements include all material adjustments necessary for 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 transactions and assumptions as if they had occurred on September 30, 2002:

(a) Additional Properties Acquisition:

On November 15, 2002 Harvest acquired the Additional Properties for $53.2 million. This acquisition was financed by $38.2 million of bank borrowings, $10 million of loans from Caribou Capital Corp., and the application of the $5.0 million property purchase deposit. In conjunction with this acquisition, Harvest entered into a sales agreement to deliver 6,000 bbls per day of Lloydminster crude oil until December 31, 2003 at a price between U.S. $22.63 and U.S. $25.48 per bbl less a fixed price differential of U.S. $8.233 per bbl. To meet the contract requirements, Harvest will have to purchase up to 1,000 bbls per day of diluents to blend with its production. On closing, the vendor indicated its intent to charge Harvest an additional $5.8 million for the properties. Management believes that such amount is not owing to the vendor and accordingly, the additional amount has not been included in the cost of the purchase. This dispute is expected to be resolved through an arbitration process and any amount paid and not recoverable will be recorded as capital assets upon settlement.

The pro forma consolidated balance sheet assumes that the acquisition cost of the Additional Properties was $57.5 million and this amount was financed with $42.5 million of bank borrowings, $10 million in loans from Caribou Capital Corp., and application of the $5 million property purchase deposit.

(b) Bank Loans:

On July 4, 2002 Harvest entered into a bank facility agreement with a Canadian bank (the “Initial Facility”). The Initial Facility was a revolving credit facility to a maximum of $18 million. On November 14, 2002 Harvest entered into a new term 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. On November 15, 2002 Harvest borrowed $56.5 million (U.S. $35.8 million) to repay $12.3 million owed on the Initial Facility and to partially finance the acquisition of the Additional Properties. Harvest paid fees totaling approximately $2.3 million for the New Facility.

The pro forma consolidated balance sheet at September 30, 2002 assumes that the Initial Facility was repaid with funds from the New Facility and deferred financing charges relating to the Initial Facility of $338,000 ($196,000 after income taxes) were charged against income.

(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”). 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.

(d) Trust Debenture:

On August 15, 2002 the Trust issued a trust debenture (the “Trust Debenture“) for proceeds totaling $5.0 million. On December 5, 2002 the Trust Debenture was settled by the issue of 5,000,000 Trust Units and $34,829 in cash for accrued interest.

The pro forma consolidated balance sheet assumes that the Trust Debenture was settled on September 30, 2002 by the issue of 5,000,000 Trust Units and a cash payment of $12,879 for accrued interest.

(e) Unit Issuance – Initial Public Offering:

On December 5, 2002 the Trust completed its initial public offering by the issue of 3,750,000 Trust Units for proceeds of $27.6 million, net of a 6% underwriters’ fee and $600,000 of issue costs. The net proceeds were used to fully repay $22.4 million owed on the Interim Loan and $5.2 million to partially repay borrowings under the New Facility.

The pro forma consolidated balance sheet assumes that the initial public offering was completed on September 30, 2002 with the net proceeds being applied to fully repay the Interim Loan and to partially repay the New Facility. In addition, upon the completion of the initial public offering the 100 Trust Units held by the Trustee were cancelled by the payment of $1.

(f) Unit Issuance – Underwriters’ Over-allotment Option:

On December 17, 2002 the Trust issued 562,500 in Trust Units as a result of the exercise by the underwriters of an over-allotment option granted by the Trust pursuant to the initial public offering.

The pro forma consolidated balance sheet assumes the exercise of the over-allotment option on September 30, 2002 providing $4.2 million of proceeds to repay borrowings under the New Facility.

(g) Unit Issuance – Exercise of Caribou Warrants

Warrants granted to Caribou as a fee for providing the Interim Loan were exercised on January 24, 2003.

The pro forma consolidated balance sheet assumes that the warrants were exercised on September 30, 2002 and the $150,000 proceeds were added to cash.

(h) Special Warrants Financing:

Pursuant to an underwriting agreement the Trust issued 1,500,000 Special Warrants that are exercisable into 1,500,000 Trust Units at no additional cost. The Special Warrants issue closed on February 4, 2003 and provided proceeds of $14,050,000, net of a 5% underwriters' fee and estimated issue costs of $200,000. The net proceeds were added to working capital and used to partially repay borrowings under the New Facility.

The pro forma consolidated balance sheet assumes that the Special Warrant financing was completed on September 30, 2002 and the $14.0 million of net proceeds were applied to partially repay the New Facility.

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

The pro forma consolidated statement of income for the nine months ended September 30, 2002 has been prepared assuming that the transactions described in note 2 were completed on January 1, 2002:

(a) The pro forma consolidated statement of income reflects a provision for depletion, depreciation and amortization using the full cost method of accounting based on the combined proved reserves and production volumes and incorporating the acquisition costs and $12.8 million of estimated future development costs.

(b) The pro forma consolidated statement of income has been adjusted to reflect the impact of $9.7 million of estimated future site restoration and reclamation costs.

(c) The pro forma consolidated statement of income reflects an increase in financing charges as a result of bank debt on the acquisition and the amortization of financing charges.

The pro forma consolidated statement of income assumes that the principal amount of debt borrowed under the New Facility at January 1, 2002 was approximately $34.9 million. Interest charges in respect of the debt have been determined assuming an effective interest rate of 6.805% per annum (based upon a lender's prime rate of 4.25% per annum plus an applicable margin of 1.875% per annum and withholding tax yield protection of 0.68% 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 nine-month period ending September 30, 2002 and therefore no adjustment to income was necessary for exchange rate changes.

The pro forma consolidated statement of income reflects a charge of $1.2 million in respect of the amortization of $2.3 million in deferred financing charges being amortized over the 17-month term of the New Facility.

(d) The amount included in the statement of income for general and administrative expenses has been determined on the basis of the anticipated actual expenditures, net of $750,000 of overhead charges capitalized. The total general and administrative costs for the nine months ended September 30, 2002 amounts to approximately $0.88 per barrel of oil equivalent of production. General and administrative costs incurred by the vendors are less relevant given the different nature of their operations to those which will be carried on by the Trust. Management has reviewed the financial statements of four other public energy trusts that are similar in size to the Trust and has determined that the general and administrative expenditures of the Trust included in the nine-month pro forma financial statements are reasonable.

(e) 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 unitholders. Accordingly, no future income taxes have been included in the pro forma consolidated statement of income.

Current taxes reflected in the pro forma consolidated statement of income are in respect of large corporation taxes of Harvest.

(f) The net income per unit calculations gives effect to the issuance 10,962,500 Trust Units as at January 1, 2002.

On November 25, 2002 the Trust established a Trust Unit incentive plan. To February 18, 2003, the Trust has granted rights to purchase 820,000 Trust Units at an average price of 8.76 per Trust Unit. In computing diluted income per unit, it was assumed that 130,000 Trust Units would be added to the 10,962,500 Trust Units outstanding for the nine-month period ended September 30, 2002 to reflect the dilutive effect of the rights issued.

CERTIFICATE OF THE TRUST AND PROMOTERS

Dated: March 7, 2003

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 9 of the *Securities Act* (Alberta) and by Part XV of the *Securities Act* (Ontario).

HARVEST ENERGY TRUST
By: Harvest Operations Corp.

(Signed) "*Jacob Roorda*"
President and as chief executive officer

(Signed) "*David Fisher*"
Vice President, Finance and as chief financial officer

On behalf of the Board of Directors

(Signed) "*M. Bruce Chernoff*"
Director

(Signed) "*Hank B. Swartout*"
Director

PROMOTERS

(Signed) "*M. Bruce Chernoff*"

(Signed) "*Kevin A. Bennett*"

CERTIFICATE OF THE UNDERWRITERS

Dated: March 7, 2003

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 9 of the *Securities Act* (Alberta) and by Part XV of the *Securities Act* (Ontario).

FirstEnergy Capital Corp.

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

Haywood Securities Inc.

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