HARVEST ENERGY TRUST

ANNUAL INFORMATION FORM

For the year ended December 31, 2006

MARCH 29, 2007

TABLE OF CONTENTS

Page

GLOSSARY OF TERMS

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

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

"**Administration Agreement**" means the agreement dated September 27, 2002 between the Trustee and Harvest Operations pursuant to which Harvest Operations provides certain administrative and advisory services in connection with the Trust. See "General Description of Capital Structure".

"**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.

"**Birchill**" means Birchill Energy Limited, a private company which, at the date of its acquisition by Harvest owned certain petroleum and natural gas properties which are described in "General Development of the Business - Year ended December 31, 2006".

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

"**BRP**" means Breeze Resources Partnership, a general partnership formed under the laws of Alberta.

"**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.

"**CNG Trust**" means Calpine Natural Gas Trust, a trust organized under the laws of the Province of Alberta, wholly owned by the Trust.

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

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum.

"**Credit Facilities**" or "**Three Year Extendible Revolving Credit Facility**" means the credit facilities provided by the Current Lenders as more fully described in Note 10 to Harvest's audited consolidated financial statements for the year ended December 31, 2006 filed on www.sedar.com.

"**Current Lenders**" means the syndicate of lenders to Harvest Operations pursuant to the Current Bank Facility.

"**Debentures**" means, collectively, the 10.5% Debentures Due 2008, the 9% Debentures Due 2009, the 8% Debentures Due 2009, the 6.5% Debentures Due 2010, the 6.40% Debentures Due 2012, the 7.25% Debentures Due 2013 and the 7.25% Debentures Due 2014.

"**Debenture Indenture**" means, collectively, the trust indenture dated January 29, 2004, a first supplemental indenture dated August 10, 2004, a second supplemental indenture dated August 2, 2005, a third supplemental indenture dated November 22, 2006 and a fourth supplemental indenture dated January 25, 2007 among the Trust, Harvest Operations and Valiant Trust Company and the trust indenture dated January 15, 2003 and a supplemental indenture dated October 20, 2005 between VERT and Computershare Trust Company of Canada.

"**Debenture Trustee**" means, as applicable, the trustee of the 9% Debentures Due 2009, 8% Debentures Due 2009, 6.5% Debentures Due 2010, 7.25% Debentures Due 2013 and 7.25% Debentures Due 2014, Valiant Trust Company or the trustee of the 10.5% Debentures due 2008 and the 6.40% Debentures due 2012, Computershare Trust Company of Canada.

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

"**8% Debentures Due 2009**" means the 8% convertible unsecured subordinated debentures of the Trust due September 30, 2009.

"**6.5% Debentures Due 2010**" means the 6.5% convertible unsecured subordinated debentures of the Trust due December 31, 2010.

"**10.5% Debentures Due 2008**" means the 10.5% convertible unsecured subordinated debentures of the Trust due January 31, 2008 assumed on February 3, 2006 pursuant to the terms of the Viking Arrangement.

"**6.40% Debentures Due 2012**" means the 6.40% convertible unsecured subordinated debentures of the Trust due October 31, 2012 assumed on February 3, 2006 pursuant to the terms of the Viking Arrangement.

"**7.25% Debentures Due 2013**" means the 7.25% convertible unsecured subordinated debentures of the Trust due September 30, 2013 issued on November 22, 2006.

"**7.25% Debentures Due 2014**" means the 7.25% convertible unsecured subordinated debentures of the Trust due February 28, 2014 issued on February 1, 2007 and February 8,2007.

"**$7^{7/8}$% Senior Notes**" means the $7^{7/8}$% Senior Notes of Harvest Operations due October 15, 2011 unconditionally guaranteed by the Trust.

"**Deferred Purchase Price Payment**" or "**DPPP**" means, collectively, the ongoing obligation of the Trust to pay to Harvest Operations, and HBT2, to the extent of the Trust's available funds, an amount up to 99% of the cost of, including any amount borrowed to acquire, any Canadian resource property acquired by Harvest Operations, or HBT2, and the cost of, including any amount borrowed to fund, certain designated capital expenditures in relation to the Properties.

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

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

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

"**East Central Alberta Properties**" means Properties located in the East Central Alberta region.

"**Exchangeable Shares**" means the non-voting exchangeable shares in the capital of Harvest Operations. On June 20, 2006, all of the then outstanding Exchangeable Shares were redeemed in exchange for cash. There are no Exchangeable Shares currently outstanding.

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

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent oil and natural gas reservoir engineers of Calgary, Alberta.

"**GAAP**" means accounting principles generally accepted in Canada.

"**Gross**" means:

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

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

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

"**Harvest**" means, collectively, the Trust and its subsidiaries, trusts and partnerships.

"**Harvest Operations**" means the Trust's wholly owned subsidiary, Harvest Operations Corp.

"**HBT1**" or "**Breeze Trust No. 1**" means Harvest Breeze Trust 1, a trust established under the laws of the Province of Alberta, wholly owned by the Trust.

"**HBT2**" or "**Breeze Trust No. 2**" means Harvest Breeze Trust 2, a trust established under the laws of the Province of Alberta, wholly owned by the Trust.

"**Independent Reserve Engineering Evaluators**" means McDaniel, GLJ and Sproule, independent oil and natural gas reservoir engineers of Calgary, Alberta, who evaluated the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries as at December 31, 2006, in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101.

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

"**Net**" means:

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

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

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

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

"**North Atlantic**" means North Atlantic Refining Limited, a private company which owned the Refinery and related marketing division described in "General Business Description – Petroleum Refining and Marketing Business", and all wholly owned subsidiaries of North Atlantic.

"**North Atlantic Acquisition**" means the acquisition of all of the shares of North Atlantic and related businesses and the entering into of the Supply and Offtake Agreement in accordance with the Purchase and Sale Agreement, which transactions were completed on October 19, 2006.

"**North Atlantic Acquisition BAR**" means the business acquisition report of the Trust dated December 11, 2006 relating to the North Atlantic Acquisition which has been filed on SEDAR at www.sedar.com.

"**NPI**" means, collectively, the net profit interest owing to the Trust pursuant to the NPI Agreements.

"**NPI Agreements**" means, collectively the agreements between Harvest Operations and the Trust, between HBT1 and the Trust and from March 1, 2007 the agreement between Harvest Reveal Inc. and the Trust to pay net profit interests to the Trust.

"**NYMEX**" means the New York Mercantile Exchange.

"**NYSE**" means the New York Stock Exchange.

"**Operating Subsidiaries**" means, collectively, Harvest Operations, REP, BRP, HBT1, HBT2, Hay River Partnership, and North Atlantic (and all direct and indirect wholly-owned subsidiaries of North Atlantic), each a direct or indirect wholly-owned subsidiary of the Trust other than REP in respect of which the Trust, indirectly, holds a 60% interest, and "**Operating Subsidiary**" means any of Harvest Operations, REP, BRP, HBT1, HBT2, Hay River Partnership or North Atlantic (or any direct or indirect wholly-owned subsidiary of North Atlantic, as applicable.

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

"**Ordinary Trust Units**" means the ordinary Trust Units of the Trust created, issued, and certified under the Trust Indenture and for the time being outstanding and entitled to the benefits thereof.

"**Permitted Investments**" means:

(a) loan advances to Harvest Operations;

(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, including the Operating Subsidiaries;

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.

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

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

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

"**Property Interests**" means petroleum and natural gas rights and related tangibles and miscellaneous interests beneficially owned by the Operating Subsidiaries.

"**Purchase and Sale Agreement**" means the purchase and sale agreement dated August 22, 2006 between the Trust and Vitol Refining Group B.V. providing for the purchase of the outstanding shares of North Atlantic and the entering into of the Supply and Offtake Agreement.

"**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.

"**Redearth Partnership**" or "**REP**" means Redearth Partnership, a partnership established under the laws of the Province of Alberta, a 60% interest of which is owned by Harvest Operations.

"**Refinery**" means the 115,000 barrel per day medium gravity sour crude hydrocracking refinery located in the Province of Newfoundland and Labrador, owned by North Atlantic, which refinery is described in "General Business Description – Petroleum Refining and Marketing Business".

"**Reserve Account**" means the cumulative amount of production and other revenues entitled to be retained by the Operating Subsidiaries pursuant to the NPI Agreements to provide for payment of production costs which the Operating Subsidiaries estimate will or may become payable in the following six months for which there may not be sufficient production revenues to satisfy such production costs in a timely manner. See "Structure of Harvest Energy Trust – Net Profits Interest Agreements".

"**Reserve Life Index**" or "**RLI**" means the amount obtained by dividing the quantity of proved plus probable reserves as at the end of the previous year, by the annualized production of petroleum, natural gas and natural gas liquids from those reserves, in the following year, as projected in the Reserve Report.

"**Reserve Report**" means, collectively, the report prepared by the Independent Reserve Engineering Evaluators dated January 1, 2007 evaluating the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries as at December 31, 2006, in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101.

"**Reserve Value**" means, for any petroleum and natural gas property at any time, the present worth of all of the estimated pre-tax cash flow net of capital expenditures from the proved plus probable reserves shown in the Reserve Report for such property, discounted at 10% and using forecast price and cost assumptions (a common benchmark in the oil and natural gas industry).

"**Special Trust Units**" means the Special Trust Units of the Trust created, issued, and certified under the Trust Indenture and for the time being outstanding and entitled to the benefits thereof. There are no Special Trust Units currently outstanding.

"**Special Voting Units**" means the Special Voting Units of the Trust created, issued, and certified under the Trust Indenture and for the time being outstanding and entitled to the benefits thereof. There are no Special Voting Units currently outstanding.

"**Sproule**" means Sproule Associates Limited, independent oil and natural gas reservoir engineers of Calgary, Alberta.

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

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

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

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

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

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

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

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

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

"**Supply and Offtake Agreement**" means the supply and offtake agreement dated October 19, 2006 entered into between North Atlantic and Vitol Refining, S.S., a wholly-owned subsidiary of the vendor to the North Atlantic Acquisition, the terms of which are summarized under the "Petroleum and Marketing Business – Supply and Offtake Agreement".

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

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

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

(a) the amount paid to settle the Trust;

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

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

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

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

(f) any Subsequent Investment;

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

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

"**Trust Indenture**" means the third amended and restated trust indenture dated February 3, 2006 between the Trustee and Harvest Operations as such indenture may be further amended by supplemental indentures from time to time.

"**Trust Unit**" means a trust unit of the Trust and unless the context otherwise requires means Ordinary Trust Units.

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

"**TSX**" means the Toronto Stock Exchange.

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

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

"**VERT**" means Viking Energy Royalty Trust, an open-end, unincorporated investment trust established under the laws of the Province of Alberta on November 5, 1996 pursuant to a trust indenture dated November 5, 1996 as amended and restated effective February 3, 2006.

"**Viking**" means, collectively, VERT and its subsidiaries, trusts and partnerships.

"**VHI**" or "**Viking Holdings**" means Viking Holdings Inc., a corporation incorporated under the *Business Corporations Act* (Alberta) by VERT on August 13, 1997 and which amalgamated with Harvest Operations on July 1, 2006, with the amalgamated corporation continuing under the name "Harvest Operations Corp.".

"**Viking Arrangement**" means the Plan of Arrangement involving Harvest, Harvest Operations, VERT, VHI, Harvest securityholders and Viking unitholders as approved by the Harvest securityholders and the Viking unitholders on February 2, 2006 and effective February 3, 2006.

"**Viking Acquisition BAR**" means the business acquisition report of the Trust dated April 18, 2006 relating to the Viking Arrangement which has been filed on SEDAR at www.sedar.com.

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

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

ABBREVIATIONS

Oil and Natural Gas Liquids

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

Natural Gas

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

Other

AECO	EnCana Corporation's natural gas storage facility located at Suffield, Alberta.
BOE	barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one Bbl of oil, unless otherwise specified. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/d	barrels of oil equivalent per day.
MBOE	thousand barrels of oil equivalent.
MMBOE	million barrels of oil equivalent.
OOIP	original oil in place.
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.
ºAPI	The measure of the density or gravity of liquid petroleum products derived from a specific gravity.
MW	megawatts of electrical power.
3D	three dimensional.
Darcies	the measure of permeability (being the ease with which a single fluid will flow through connected pore space when a pressure gradient is applied).
Porosity	The measure of the fraction of pore space of a reservoir.
$000	thousands of dollars
$millions	millions of dollars

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
feet	Metres	0.305
metres	Feet	3.281
miles	Kilometres	1.609
kilometres	Miles	0.621
acres	Hectares	0.405
hectares	Acres	2.471

EXCHANGE RATE INFORMATION

All dollar amounts set forth in this prospectus are expressed in Canadian dollars, except where otherwise indicated. References to Canadian dollars, CDN$ or $ are to the currency of Canada and references to U.S. dollars or US$ are to the currency of the United States.

The following table sets forth for each period indicated, the average, high, low and end of period noon buying rates in New York for cable transfers as certified for customs purposes by the Federal Reserve Bank of New York (the "noon buying rate"). Such rates are set forth as U.S. dollars per $1.00 and are the inverse of the rates quoted by the Federal Reserve Bank of New York for Canadian dollars per US$1.00.

	Year Ended December 31,		
	2006	2005	2004
High	0.9099	0.8690	0.8493
Low	0.8528	0.7872	0.7158
Period End	0.8581	0.8579	0.8310
Average (1)	0.8846	0.8276	0.7702

Note:

(1) Average represents the average of the rates on the last day of each month during the period.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form and documents incorporated by reference herein, constitute forward-looking statements. These statements relate to future events and future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are subject to certain risks and uncertainties that could cause actual results to differ materially from those included in the forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. Harvest Operations believes the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In particular, this Annual Information Form, and the documents incorporated by reference herein, contain forward-looking statements pertaining to:

- expected financial performance in future periods;
- expected increases in revenue attributable to development and production activities;
- estimated capital expenditures;
- competitive advantages and ability to compete successfully;
- intention to continue adding value through drilling and exploitation activities;
- emphasis on having a low cost structure;
- intention to retain a portion of cash flows after distributions to repay indebtedness and invest in further development of our properties;
- reserve estimates and estimates of the present value of our future net cash flows;
- methods of raising capital for exploitation and development of reserves;
- factors upon which to decide whether or not to undertake a development or exploitation project;
- plans to make acquisitions and expected synergies from acquisitions made;
- expectations regarding the development and production potential of petroleum and natural gas properties;
- treatment under government regulatory regimes including without limitation, environmental and tax regulation;

- overall demand for gasoline, low sulphur diesel, jet fuel, furnace oil and other refined products; and
- the level of global production of crude oil feedstocks and refined products.

With respect to forward-looking statements contained in this Annual Information Form and the documents incorporate by reference herein, Harvest has made assumptions regarding, among other things:

- future oil and natural gas prices and differentials between light, medium and heavy oil prices;
- the cost of expanding Harvest's property holdings;
- the ability to obtain equipment in a timely manner to carry out development activities;
- the ability to market oil and natural gas successfully to current and new customers;
- the impact of increasing competition;
- the ability to obtain financing on acceptable terms;
- the ability to add production and reserves through development and exploitation activities; and
- the ability to produce gasoline, low sulphur diesel, jet fuel, furnace oil, and other refined products that meet customer specifications.

Some of the risks that could affect Harvest's future results and could cause results to differ materially from those expressed in forward-looking statements include:

- the volatility of oil and natural gas prices, including the differential between the price of light, medium and heavy oil;
- the uncertainty of estimates of petroleum and natural gas reserves;
- the impact of competition;
- difficulties encountered in the integration of acquisitions;
- difficulties encountered during the drilling for and production of oil and natural gas;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- foreign currency fluctuations;
- the uncertainty of Harvest's ability to attract capital;
- changes in, or the introduction of new, government regulations relating to the oil and natural gas business including without limitation, environment and tax regulations;
- costs associated with developing and producing oil and natural gas;
- compliance with environmental and tax regulations;
- liabilities stemming from accidental damage to the environment;
- loss of the services of any of Harvest's senior management or directors;
- adverse changes in the economy generally;
- the volatility of refining gross margins including the price of feedstocks as well as the prices for refined products; and
- the stability of the Refinery throughput performance.

Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. Except as required by law, neither the Trust nor Harvest Operations undertakes any obligation to publicly update or revise any forward-looking statements and readers should also carefully consider the matters discussed under the heading "Risk Factors" in this Annual Information Form.

NON-GAAP MEASURES

Harvest uses certain financial reporting measures that are commonly used as benchmarks within the petroleum and natural gas industry. These measures include: "Cash Flow" as cash flow from operating activities before changes in non-cash working capital and settlement of asset retirement obligations, "Payout Ratio", "Cash G&A", "Operating Netbacks" and "Gross Margin". These measures are not defined under Canadian generally accepted accounting principles and should not be considered in isolation or as an alternative to conventional Canadian GAAP measures. Certain of these measures are not necessarily comparable to a similarly titled measure of another company or trust. When these measures are used, they have been footnoted and the footnote to the applicable measure notes that the measure is "non-GAAP" and contains a description of how to reconcile the measure to the applicable financial statements. These measures should be given careful consideration by the reader.

Specifically, management uses Cash Flow as cash flow from operating activities before changes in non-cash working capital and settlement of asset retirement obligations. Under Canadian GAAP, the accepted definition of cash flow from operating activities is net of changes in non-cash working capital and settlement of asset retirement obligations. Cash Flow as presented is not intended to represent an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with Canadian GAAP. Management believes its usage of Cash Flow is a better indicator of the Trust's ability to generate cash flows from future operations. Payout Ratio, Cash G&A and Operating Netbacks are additional non-GAAP measures used extensively in the Canadian energy trust sector for comparative purposes. Payout Ratio is the ratio of distributions to total Cash Flow. Operating Netbacks are always reported on a per BOE basis, and include gross revenue, royalties and operating expenses, net of any realized gains and losses on related risk management contracts. Cash G&A are G&A expenses, excluding the effect of unit based compensation plans. Gross Margin is commonly used in the refining industry to reflect the net cash received from the sale of refined product after considering the cost to purchase the feedstock and is calculated by deducting Purchased products for resale and processing from total revenue. Operating income is also commonly used in the petroleum and natural gas and in the refining and marketing industries to reflect operating results before items not directly related to operations.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Trust's most recently completed financial year, being the year ended December 31, 2006.

STRUCTURE OF HARVEST ENERGY TRUST

Harvest Energy Trust

Harvest Energy Trust (the "**Trust**") is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta on July 10, 2002 pursuant to the Trust Indenture between Harvest Operations, a wholly owned subsidiary and administrator of the Trust, and Valiant Trust Company as Trustee. The Trust Indenture has been amended from time to time, the latest material amendments being approved at the special meeting of Unitholders held February 2, 2006. The Trust's assets consist of securities, unsecured debt and net profits interests on the oil and natural gas assets of several direct and indirect subsidiaries, trusts and partnerships as well as direct ownership of royalties on certain petroleum and natural gas properties. The head and principal office of the Trust is located at Suite 2100, 330 - 5th Avenue S.W., Calgary, Alberta T2P 0L4 while the registered office of the Trust is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta T2P 3N9. The Trust is managed by Harvest Operations pursuant to the Administration Agreement.

The beneficiaries of the Trust are the holders of its Trust Units who receive monthly distributions from the Trust's net cash flow from its various investments after certain administrative expenses and the provision for interest due to the holders of convertible debentures. Pursuant to the Trust Indenture, the Trust is required to distribute 100% of its taxable income to its Unitholders each year and its activities are limited to holding and administering permitted investments and making distributions to its Unitholders.

The business of the Trust is to indirectly exploit, develop and hold interests in petroleum and natural gas properties through its investments. Cash flow from the petroleum and natural gas properties flows to the Trust by way of payments by Harvest Operations and Breeze Trust No. 1 pursuant to NPIs held by the Trust, interest and principal payments by Harvest Operations, Breeze Trust No. 1 and Breeze Trust No. 2 on unsecured debt owing to the Trust and payments by Breeze Trust No. 1 and Breeze Trust No. 2 of trust distributions. The Trust also receives cash flow from its direct royalties on certain petroleum and natural gas properties. The Trust now receives interest and principal on unsecured debt owing to the Trust as well as partnership distributions from Harvest Refining General Partnership and trust distributions from CNG Trust.

Pursuant to the terms of each respective net profits interest agreement, the Trust is entitled to payments equal to the amount by which 99% of the gross proceeds from the sale of production from petroleum and natural gas properties exceed 99% of certain deductible expenditures. Deductible expenditures may include discretionary amounts to fund capital expenditures, to repay third party debt and to provide for working capital required to maintain the operations of the operating subsidiaries.

Operating Subsidiaries

The business of the Trust is carried on by Harvest Operations and its other operating subsidiaries, Breeze Trust No. 1, the Redearth Partnership and the North Atlantic Refining Limited Partnership. The activities of the operating subsidiaries are financed through interest bearing notes from the Trust, the purchase of NPIs by the Trust and third party debt.

Harvest Operations Corp., a taxable corporation

Harvest Operations was incorporated under the ABCA on May 14, 2002 as 989131 Alberta Ltd. and on May 17, 2002, changed its name to Coyote Energy Inc. and then changed its name again on September 17, 2005 to "Harvest Operations Corp." All of the issued and outstanding common shares of Harvest Operations are held for the benefit of the Trust. On January 1, 2004, Harvest Operations amalgamated with Westcastle Energy Inc. and continued as "Harvest Operations Corp." On June 30, 2004, Harvest Operations amalgamated with Storm Energy Ltd. and continued as "Harvest Operations Corp." On July 1, 2006, Harvest Operations amalgamated with VHI and continued as "Harvest Operations Corp." On January 1, 2007, Harvest Operations amalgamated with Harvest BEL Inc. and 251849 Alberta Ltd. and continued as "Harvest Operations Corp."

In addition to administering the affairs of the Trust, Harvest Operations manages the affairs of the other subsidiaries and is responsible for providing all of the technical, engineering, geological, land management, financial, administrative and commodity marketing services relating to Harvest's petroleum and natural operations.

Redearth Partnership, a general partnership

Redearth Partnership is a general partnership formed on August 23, 2002 under the laws of the Province of Alberta pursuant to a partnership agreement dated August 23, 2002. Harvest Operations holds a 60% ownership interest in Redearth Partnership. Redearth Partnership's assets consist of direct ownership interest in properties located in north central Alberta purchased in June 2004 as part of the Storm Energy Ltd. acquisition.

Harvest BEL Inc., a taxable corporation

1126838 Alberta Ltd. (a wholly-owned subsidiary of Harvest Operations incorporated to acquire Birchill Energy Limited) amalgamated with Harvest BEL Inc. (formerly Birchill Energy Limited) on August 15, 2006 and continued as "Harvest BEL Inc." Harvest BEL Inc.'s assets were comprised of the petroleum and natural gas properties from Birchill Energy Limited its operations were limited to the period from August 15, 2006, the date of the acquisition of Birchill Energy Limited, until the amalgamation of Harvest BEL Inc., Harvest Operations Corp. and 251849 Alberta Ltd. on January 1, 2007.

Harvest Breeze Trust No. 1, a commercial trust

Breeze Trust No. 1 is an unincorporated commercial trust established under the laws of the Province of Alberta on July 8, 2004 pursuant to a Trust Indenture dated July 8, 2004. Breeze Trust No. 1 is wholly owned by the Trust and its assets consist of the intangible portion of direct ownership interests in petroleum and natural gas properties purchased from the Breeze Resources Partnership and the Hay River Partnership and a 99% interest in each of those partnerships.

Harvest Breeze Trust No. 2, a commercial trust

Breeze Trust No. 2 is an unincorporated commercial trust established under the laws of the Province of Alberta on July 8, 2004 pursuant to a Trust Indenture dated July 8, 2004. Breeze Trust No. 2 is wholly owned by the Trust and its assets consist of a 1% interest in each of the Breeze Resources Partnership and the Hay River Partnership.

Breeze Resource Partnership, a general partnership

Breeze Resource Partnership (indirectly wholly-owned by the Trust) is a general partnership formed on June 30, 2004 under the laws of the Province of Alberta pursuant to a partnership agreement dated June 30, 2004. Breeze Resource Partnership's assets consist of the tangible portion of direct ownership interest in petroleum and natural gas properties located in east central Alberta and southern Alberta purchased in September 2004.

Hay River Partnership, a general partnership

Hay River Partnership (indirectly wholly-owned by the Trust) is a general partnership formed on December 20, 2004 under the laws of the Province of Alberta pursuant to a partnership agreement dated December 20, 2004. Hay River Partnership's assets consist of the tangible portion of direct ownership interests in petroleum and natural gas properties located in northeastern British Columbia purchased in August 2005.

Harvest Refining General Partnership., a general partnership

Harvest Refining General Partnership is a general partnership formed on September 27, 2006 under the laws of the Province of Alberta pursuant to a partnership agreement dated September 27, 2006 between the Trust, which holds a 99% partnership interest and CNG Trust which holds a 1% partnership interest. Harvest Refining General Partnership's assets consist of unsecured debt owing from each of VERT and North Atlantic as well as a 100% equity interest in both VERT and North Atlantic.

North Atlantic Refining Limited, a taxable corporation

Harvest North Atlantic Acquisition Corp (a wholly-owned subsidiary of Harvest Refining General Partnership incorporated on September 21, 2006 to acquire North Atlantic Refining Limited) amalgamated with North Atlantic Refining Limited pursuant to The Corporations Act of the Province of Newfoundland and Labrador on October 19, 2006 and continued as "North Atlantic Refining Limited". North Atlantic's assets consist of preferred partnership units representing 75% of the total preferred partnership interest in the North Atlantic Refining Limited Partnership as well as common partnership units representing 5% of the total common partnership interest in the same partnership.

North Atlantic manages the affairs of North Atlantic Refining General Partnership and is responsible for providing the engineering, operations and administrative services related to Harvest's refining operations. The feedstock supply management and marketing of refined products has been contracted to Vitol Refining, S.A. pursuant to the Supply and Offtake Agreement.

Viking Energy Royalty Trust, a commercial trust

Viking Energy Royalty Trust (indirectly, wholly-owned by the Trust) is a trust established under the laws of the Province of Alberta pursuant to a trust indenture dated November 5, 1996 as amended and restated effective July 1, 2003. VERT's assets consist of preferred partnership units representing 25% of the total preferred partnership interest in the North Atlantic Refining Limited Partnership as well as common partnership units representing 95% of the total common partnership interest in the same partnership.

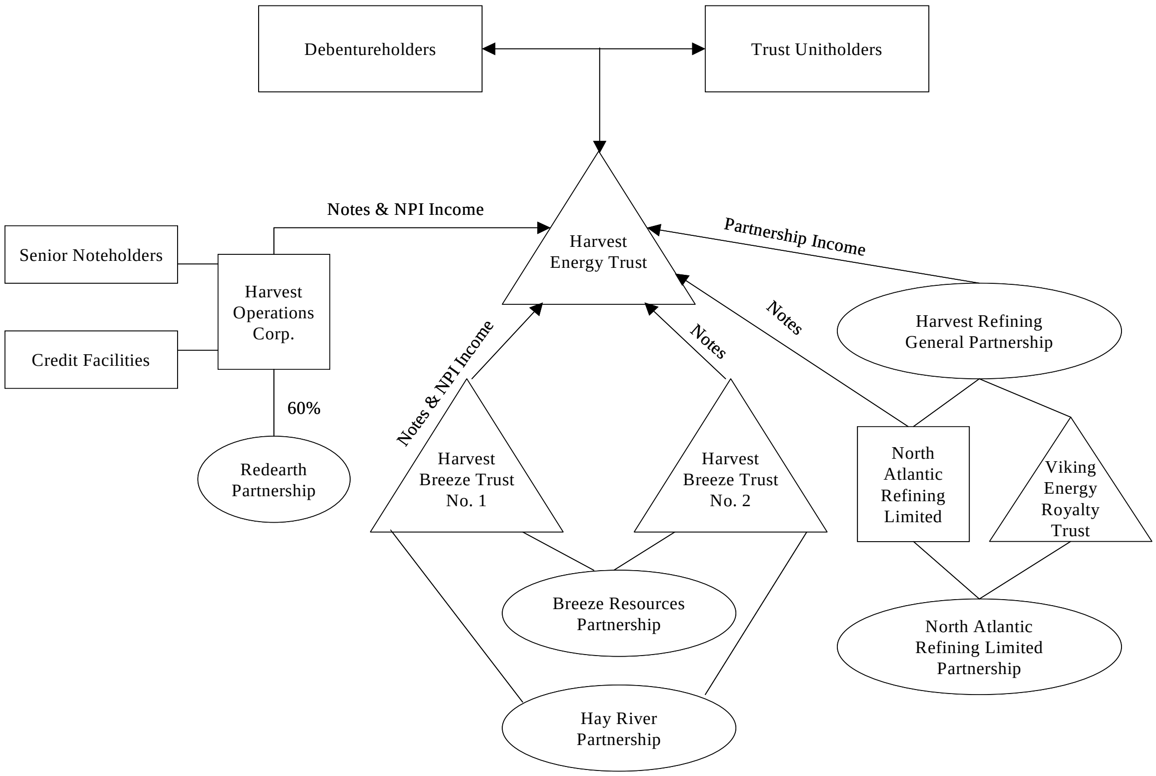
North Atlantic Refining Limited Partnership, a limited partnership

North Atlantic Refining Limited Partnership (a partnership wholly-owned by North Atlantic Refining Limited and Viking Energy Royalty Trust) is a limited partnership formed on October 13, 2006 under the laws of the Province of

Newfoundland and Labrador pursuant to a partnership agreement dated October 13, 2006. North Atlantic Refining Limited Partnership's assets consist of the Refinery and related retail marketing assets.

Organizational Structure of the Trust

The structure of the Trust and its significant subsidiaries including the flow of cash from the Properties through to the Unitholders is set forth below**:**



Notes:

(1) All operations and management of the Trust and the Trust's operating subsidiaries are conducted through HOC except for the operations of the North Atlantic Refining Limited Partnership which is conducted by the management and employees of North Atlantic Refining Limited.

(2) The Trust receives regular monthly net profits interest payments as well as distributions and interest payments from Harvest Operations, Breeze Trust No. 1, and Harvest Refining General Partnership, and trust partnership distributions from Harvest Breeze Trust No. 1, Harvest Breeze Trust No. 2, CNG Trust and Harvest Refining General Partnership.

(3) Breeze Trust No. 1 and Breeze Trust No. 2 have also issued priority trust units to HOC.

The Net Profits Interest Agreements

The net profits interests consist of the rights to receive a monthly payment from the Operating Subsidiaries pursuant to the terms of the net profits interest agreements equal to ninety-nine percent (99%) of the amount by which the gross proceeds from the sale of production attributable to Property Interests for such month (the "**NPI Revenues**") exceed certain deductible production costs for such period. The residual 1% share of gross proceeds from the sale of production that does not form part of the net profits interests is retained by the Operating Subsidiaries, together with any income derived from Properties that are not Working Interests in Canadian resource properties. This residual revenue is used to defray certain expenses and capital expenditures of the Operating Subsidiaries.

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

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

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

Deferred Purchase Price Payment

Pursuant to the net profits interest agreements, the Deferred Purchase Price Payment consists of an ongoing obligation of the Trust to pay to the Operating Subsidiaries, to the extent of the Trust's available funds, an amount equal to the sum of the following, less amounts financed by the Operating Subsidiaries from debt:

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

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

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

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

To the extent that the Operating Subsidiaries designate an expenditure as subject to the Deferred Purchase Price Payment:

(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 net profits interest, and therefore will not reduce payments from the net profits interest to the Trust or distributions to Unitholders;

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

(c) the cost to the Trust of the designated expenditure will be added to the Canadian oil and gas property expense ("**COGPE**") account of the Trust, thus creating additional tax deductions; and

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

Reserve Account

Under the net profits interest agreements, the Operating Subsidiaries are entitled to reserve such amounts of the revenues received from Production and other income received by the Operating Subsidiaries in respect of the Properties if, as and when Harvest Operations determines, in its reasonable discretion, that it is prudent to do so in accordance with prudent business practices, to provide for payment of future production costs. Amounts Allocated by the Operating Subsidiaries to the Reserve Account are required to be used by the Operating Subsidiaries to fund the payment of production costs. When such production costs are paid, the amounts will be adjusted in the calculation of the net profits interest.

GENERAL DEVELOPMENT OF THE BUSINESS

Harvest was formed in July 2002 and subsequently acquired 2,750 BOE/d of medium gravity oil production in the Thompson Lake area of east central Alberta for cash consideration of $27.2 million. In November 2002, Harvest acquired an additional 5,750 BOE/d of heavy oil production in the Hayter area also in east central Alberta for cash consideration of $49.0 million. These acquisitions were funded by an initial $5 million of founders' capital, $31.7 million of net proceeds from Harvest's initial public offering and borrowings under term credit facilities.

Harvest continued its acquisition of heavy oil production in east central Alberta in 2003 with the purchase of two properties in the Killarney area with production of 925 BOE/d during April/May for an aggregate consideration of $15.3 million. On June 27, 2003, Harvest acquired approximately 1,350 BOE/d of heavy oil production in east central Alberta with its acquisition of all the common shares of Westcastle Energy Inc., a private company, and a net profits interest in certain producing properties held by that company for an aggregate purchase price of $15.3 million. On October 1, 2003, Harvest acquired a further 5,200 BOE/d of light oil production in the Carlyle area of southeast Saskatchewan for cash consideration of $79.5 million, prior to adjustments and transaction costs.

At the end of 2003, Harvest's exit production totalled 15,400 BOE/d comprised of approximately 60% light and medium oil and 40% heavy oil with capital spending for the year totalling $27.2 million.

Year ended December 31, 2004

On June 30, 2004, Harvest acquired approximately 4,000 BOE/d of light oil production in the Red Earth area of north central Alberta with its acquisition of all of the common shares of Storm Energy Ltd. In addition to assuming bank debt of $56.8 million and a working capital deficiency of $10.5 million, Harvest's acquisition costs included $75.0 million of cash consideration, and the issuance of 2,720,837 Trust Units and 600,587 Exchangeable Shares with ascribed values of $40.2 million and $8.9 million, respectively, for an aggregate consideration of approximately $192.2 million including $0.8 million of transaction costs.

On September 2, 2004, Harvest acquired approximately 20,000 BOE/d of production in east central Alberta and southern Alberta, including approximately 28,000 Mcf/d of natural gas production at Crossfield and Cavalier, with its acquisition of the Breeze Resources Partnership for cash consideration of $511.4 million. The more significant oil properties included in this acquisition were the heavy oil assets at Suffield and medium gravity production at Badger.

During 2004, Harvest's production averaged approximately 23,000 BOE/d with a year end exit rate of 37,000 BOE/d comprised of approximately 43% light and medium oil, 41% heavy oil and 16% natural gas and associated liquids with capital spending on internal development opportunities increased to $42.7 million.

Year ended December 31, 2005

On August 2, 2005, Harvest acquired approximately 5,200 BOE/d of medium gravity oil production (24° API) in north eastern British Columbia with its acquisition of the Hay River Partnership for cash consideration of $237.8 million. The production from Hay River sells at a premium to Harvest's other medium gravity production and due to its northern location, receives preferred royalty treatment afforded to heavy oil producers.

During 2005, Harvest's production averaged approximately 36,500 BOE/d with a year end exit rate of approximately 38,800 BOE/d comprised of approximately 53% light and medium oil, 34% heavy oil and 13% natural gas and associated liquids. Capital spending on internal development opportunities increased to $120.5 million, an increase of $77.8 million over the prior year.

Year ended December 31, 2006

On November 28, 2005, Harvest entered into a Pre-Arrangement Agreement outlining the terms and conditions upon which Harvest and Viking Energy Royalty Trust ("**Viking**") were prepared to complete a business combination and on December 23, 2005, Harvest and Viking entered into an Arrangement Agreement to merge the two trusts based on an exchange ratio of 0.25 Harvest Trust Units for every Viking trust unit with Harvest receiving all of the assets of Viking. On February 2, 2006, the securityholders of Harvest and the unitholders of Viking approved a resolution to affect a plan of arrangement with the Alberta Court of Queens Bench granting the required order on February 3, 2006. In addition to the issuance of 46,040,788 Trust Units with an ascribed value of $1,638.1 million, Harvest also assumed $106.2 million of bank debt and the obligations of Viking's 10.5% and 6.40% unsecured subordinated convertible debentures with $35.1 million and $175.0 million of face value outstanding, respectively, bringing the total consideration for the acquisition to $1,975.3 million including acquisition costs of $4.6 million. Production from all of Viking's assets was approximately 24,000 BOE/d comprised of approximately 50% natural gas, and 50% oil and natural gas liquids with its core areas of production including Markerville, Bellshill Lake, Bashaw, Channel Lake, Alexis, Tweedie/Wappau and Greater Richdale, all in Alberta as well as Kindersley in Saskatchewan. Following the completion of the Viking acquisition, Harvest had an initial productive capacity of 64,000 BOE/d comprised of approximately 50% light and medium gravity oil, 25% heavy oil and 25% natural gas and significant undeveloped land and property enhancement opportunities.

On July 26, 2006, Harvest entered into an agreement to purchase all of the issued and outstanding shares of Birchill Energy Limited for cash consideration of $446.8 million. At the date of acquisition, Birchill's production was approximately 6,300 BOE/d weighted 65% natural gas and 35% light/medium oil and natural gas liquids with approximately 57% produced from properties located in areas adjacent to Harvest's Markerville, Ferrier and Willesden Green properties. In addition, Birchill's Mulligan property in the Peace River Arch produced approximately 2,000 BOE/d of natural gas and natural gas liquids. Harvest has identified 66 prospective drilling locations targeting primarily in tight gas, shallow gas and prolific light oil Leduc reef formations that will form part of Harvest's ongoing capital program over the next two years.

On August 22, 2006, Harvest entered into the Purchase and Sale Agreement to acquire all of the issued and outstanding shares of North Atlantic for cash consideration of $1,597.8 million and closed the transaction on October 19, 2006. The principal asset of North Atlantic is the Refinery, a 115,000 barrel per stream day sour crude hydrocracking refinery located in the Province of Newfoundland and Labrador and a marketing division with 69 gasoline stations, a home heating business and a commercial and wholesale petroleum products business, also located in the Province of Newfoundland and Labrador. The Refinery is capable of processing a wide range of crude oil feedstocks with a sulphur content as high as 3.5% and an API gravity in the range of 25° to 40° and has a docking facility capable of handling vessels in excess of 200,000 dead weight tons capable of carrying up to 2 million barrels of crude oil. The Refinery's product slate is weighted towards high quality gasoline, jet fuel and diesel fuel that are compliant with current product specifications (including sulphur, cetane and aromatic content) that are becoming increasingly restrictive. Concurrent with this acquisition by Harvest, North Atlantic entered into a Supply and Offtake Agreement with Vitol Refining S.A. that provides for the ownership of substantially all crude oil feedstock and refined product inventory at the Refinery to be retained by Vitol Refining S.A. and that during the term of the agreement, Vitol Refining S.A. granted the right and obligation to provide crude oil feedstock for delivery to the Refinery as well as the right and obligation to purchase all refined products produced by the Refinery. The acquisition of North Atlantic created a second business segment for Harvest.

During 2006, Harvest's petroleum and natural gas production averaged approximately 59,729 BOE/d with a year end exit rate of approximately 65,023 BOE/d comprised of approximately 45% light and medium oil, 25% heavy oil and 30% natural gas. Capital spending on internal development opportunities increased to $398.3 million, an increase of $277.8 million over the prior year. For the month of December 2006, the throughput of the North Atlantic refinery totalled 101,679 BOE/d, being the first month of full operations since acquiring the refinery on October 19, 2006.

Significant Acquisitions

On February 3, 2006, Harvest and Viking completed a plan of Arrangement which resulted in Harvest acquiring all of the petroleum and natural gas interests which were formerly held by Viking in exchange for 46,040,788 Harvest Trust Units. Production from all of Viking's assets was approximately 24,000 BOE/d comprised of approximately 50% natural gas, and 50% oil and natural gas liquids with its core areas of production including Markerville, Bellshill Lake, Bashaw, Channel Lake, Alexis, Tweedie/Wappau and Greater Richdale, all in Alberta as well as Kindersley in Saskatchewan. The aggregate consideration given including the assumption of Viking's bank debt and its outstanding convertible debentures as well as transactions costs was $1,975.3 million. The Trust filed a Business Acquisition Report (Form 51-102F4) dated April 18, 2006 in respect of this acquisition on SEDAR at www.sedar.com which is incorporated herein by reference.

On October 19, 2006, Harvest completed the acquisition of all of the North Atlantic Refining Limited shares and entered into the Supply and Offtake Agreement. The principal asset of North Atlantic is a 115,000 barrel per stream day sour hydrocracking refinery located in the Province of Newfoundland and Labrador and a marketing division also located in the Province of Newfoundland and Labrador. Concurrent with the acquisition of North Atlantic by Harvest, North Atlantic entered into a Supply and Offtake Agreement with Vitol Refining S.A. that provides for the ownership of substantially all crude oil feedstock and refined product inventory at the Refinery to be retained by Vitol Refining S.A. vendor and that during the term of the agreement, Vitol Refining S.A. granted the right and obligation to provide crude oil feedstock for delivery to the Refinery as well as the right and obligation to purchase all refined products produced by the Refinery. The Trust filed a Business Acquisition Report (Form 51-102F4) dated December 11, 2006 in respect of this acquisition on SEDAR at www.sedar.com which is incorporated herein by reference.

GENERAL BUSINESS DESCRIPTION

Overview

With its acquisition of North Atlantic in October 2006, Harvest became the first integrated energy trust in Canada with petroleum and natural gas operations in western Canada and a petroleum refining and related marketing business in the Province of Newfoundland and Labrador. Harvest indirectly benefits from the cash flows generated from each business segment and distributes these cash flows to its unitholders after certain administrative expenses and the provision for interest due to the holders of convertible debentures.

Harvest's petroleum and natural gas assets are located in Alberta, Saskatchewan and British Columbia. Harvest employs a disciplined approach to acquiring high working interest, large resource-in-place, producing properties and use "best practice" technical and field operational processes to extract maximum value. These operational processes include hands-on management to maintain and maximize production rates, the application of technology and selective capital investment to maximize reservoir recovery and searching for operational efficiencies to control and reduce expenses. As at March 20, 2007, Harvest employed 354 full-time employees in its petroleum and natural gas business, 222 of which are located in the head office and 132 of which are located in the field.

Commencing on October 19, 2006 with its acquisition of North Atlantic, Harvest's petroleum refining and marketing business consists of a 115,000 barrel per stream day crude oil refinery and related docking and storage facilities as well as a retail gasoline, home heating, commercial, wholesale and bunkers business all operated in Province of Newfoundland and Labrador. Concurrent with Harvest's acquisition of North Atlantic, North Atlantic entered into the Supply and Offtake Agreement with Vitol Refining S.A. that provides that the ownership of substantially all crude oil feedstock and refined product inventory at the Refinery are retained by Vitol Refining S.A. and that during the term of this agreement, Vitol Refining S.A. is granted the right and obligation to provide crude oil feedstock for delivery to the Refinery as well as the right and obligation to purchase all refined products produced by the Refinery. As at March 20, 2007, Harvest employed 570 full-time employees and 140 part-time employees in its petroleum refining and related marketing business all of which are located in the Province of Newfoundland and Labrador.

Business Strategies, Policies & Practices

Harvest's business strategy is focused on cash flow generation, acquiring under developed assets and increasing the value of its assets with proven development strategies. Prior to 2006, Harvest had applied its strategies to opportunities in the petroleum and natural gas industry in western Canada. With the valuation of petroleum and natural gas assets in western Canada ever increasing through 2005 and into 2006, the opportunities to acquire such assets with significant upside potential became difficult. As a result, in 2006 Harvest changed its focus in western Canada to aggressively pursuing development opportunities within its existing asset base in western Canada and looking beyond western Canada for acquisition opportunities.

Harvest selects business practices to enhance the current cash flow from existing assets as well as increase the longer term value of the assets. In addition, Harvest employs financial strategies to improve the predictability of its future cash flows and to ensure it retains balance sheet flexibility to be considered as a viable contender for future acquisition opportunities.

Petroleum and Natural Gas Segment

Within the petroleum and natural gas segment, Harvest employs the following specific operating strategies:

1. **Acquire Underdeveloped Properties** - Harvest will continue to selectively acquire properties with an established production history and once acquired, focus on improving resource recovery, reducing costs and extending reserve life thereby creating additional value for its unitholders. Harvest will continue to evaluate future acquisitions on the basis of recycle ratio, which is the ratio of the operating netback per BOE of production to the cost of acquiring a BOE of reserves, targeting ratios in excess of 2 to 1 which should result in strong internal rates of return.

2. **Increase Operating Netbacks** - In its petroleum and natural gas business, Harvest focuses on reducing operating costs and optimizing marketing alternatives to increase its operating netback which thereby extend the life and increase the value of its proved reserves. Cost reduction initiatives include the continuous improvements to water handling and disposal alternatives and contracting for volume discounts on well servicing and purchased materials. Optimizing marketing alternatives includes blending crude oil production to meet pricing specifications and reviewing transportation alternatives to achieve the highest prices available at the wellhead.

3. **Commodity Price Risk Management** - Harvest continues to employ commodity price management contracts to reduce the volatility of its future cash flows. For the year ended December 31, 2006, Harvest reported net cash settlements of $62.6 million from its commodity price risk management contracts, as compared to $73.0 million in the prior year, primarily from crude oil price contracts. At the end of 2006, Harvest's production consisted of approximately 45% light to medium gravity oil, 25% heavy oil and 30% natural gas which supports Harvest entering into price risk management contracts for a significant portion of its crude oil price exposure and electrical power price exposure. The cost of electric power accounts for approximately 25% of Harvest's operating costs and in Alberta's de-regulated market, the price of electric power fluctuates with the general supply and demand for electricity as well as with the price of natural gas, the feedstock of the marginal producer in Alberta. For 2007, Harvest remains exposed to approximately 20% of its crude oil price exposure with price risk management contracts in place on approximately 57% of its production at a price of US$56 with 67% participation in increased prices thereafter and a further 18% of its crude oil price offset by its royalty obligations. In respect of its electric power price exposure, Harvest has approximately 50% of its consumption contracted at an average price of $56.69/MWH through December 2008. For complete details on Harvest's price risk management contracts refer to Note 18 in Harvest's Consolidated Financial statements for the year ended December 31, 2006 filed on www.sedar.com.

4. **Insurance Coverage** - In addition to preventative maintenance operating practices, Harvest maintains property damage and business interruption insurance to mitigate the risk associated with its practice of controlling operations and future development with a high working interest in its petroleum and natural gas properties. Harvest's property damage coverage is subject to a $500,000 deductible per occurrence and a

claim limit of $111 million while the business interruption insurance covers the its five highest revenue generating properties subject to a 30 day deductible period and claim limit of $111 million. Harvest also maintains an industry standard environmental, health and safety program – See "Environmental, Health & Safety Policies & Practices").

Petroleum Refining and Related Marketing Segment

Within the petroleum refining and related marketing segment, Harvest employs the following specific operating strategies:

1. **Acquire Established Operating Facilities –** The North Atlantic operations acquired by Harvest in 2006 had over ten years of continuous operations with an established operations work force and operating plan. In respect of the related feedstock procurement and marketing of refined products, Harvest has contracted with the vendor to provide these services for a minimum period of two years. The refinery is currently configured to produce high quality gasoline and distillates from a medium gravity sour feedstock that meet or exceed the ever increasing environmental requirements. Within the North Atlantic refinery, there exists opportunities to further improve the cash flows with de-bottlenecking projects as well as "bottoms upgrading" projects. Harvest will continue to evaluate future acquisitions on the basis of established operations and proven reliability performance which should result in solid rates of return.

2. **Commodity Price Risk Management** - Harvest considers its commodity price risk exposure to have changed significantly with the acquisition of the North Atlantic refinery. Prior to this acquisition, Harvest was long approximately 45,000 BOE/d of crude oil including approximately 15,000 BOE/d of heavy oil differentials whereas subsequent to the acquisition, Harvest is long 115,000 BOE/d of refined products and short 70,000 BOE/d of medium gravity sour crude oil. Harvest contracted for much of its 2007 crude oil price contracts prior to 2006 and as a result, 2007 will be a transition year for its corporate commodity price risk management program as the focus shifts from a crude oil producer to an integrated producer of refined products. Commencing in 2008, Harvest will construct a price risk management position to reflect a long position of 45,000 BOE/d of refined products and 70,000 BOE/d of medium sour refining crack spread. Similar to the past approach on its crude oil price exposure, Harvest will likely reduce the risk on a significant portion of its price risk exposure.

3. **Insurance Coverage –** Subsequent to its acquisition by Harvest, North Atlantic maintains property damage and business interruption insurance on its refinery operations to a maximum annual loss limit of US$1 Billion subject to a property damage deductible of $7.5 million and a 45 day deductible period for the business interruption coverage. North Atlantic receives its crude oil feedstock via water born vessels and protects its exposure to marine pollution and related clean-up by requiring any vessel delivering feedstock to the refinery or shipping refined products from the refinery to carry US$1 billion of coverage per vessel and to insure the cargo for 110% of its value.

PETROLEUM AND NATURAL GAS BUSINESS
STATEMENT OF RESERVES DATA

The statement of reserves data and other oil and natural gas information set forth below (the "**Statement**") is dated March 20, 2007. The effective date of the Statement is December 31, 2006 and the preparation date of the Statement is March 20, 2007.

Disclosure of Reserves Data

Harvest retained the qualified, Independent Reserves Engineering Evaluators to evaluate and prepare reports on 100% of Harvest's crude oil and natural gas reserves as of December 31, 2006. Harvest's reserves were evaluated by McDaniel & Associates Consultants Ltd. ("**McDaniel**") (who evaluated approximately 35% of Harvest's total proved plus probable reserves), GLJ Petroleum Consultants Ltd. ("**GLJ**") (who evaluated approximately 44% of Harvest's total proved plus probable reserves) and Sproule Associates Limited ("**Sproule**") (who evaluated approximately 21% of Harvest's total proved plus probable reserves). All of Harvest's reserves were evaluated using the price and cost assumptions of McDaniel as at January 1, 2007.

The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Reserve Report has been prepared by the Independent Reserve Engineering Evaluators in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Operating Subsidiaries engaged the Independent Reserve Engineering Evaluators to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

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

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

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

Reserves Data (Constant Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2006
CONSTANT PRICES AND COSTS

	RESERVES					
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)
PROVED						
Developed Producing	62,477.3	56,386.3	34,210.9	30,779.4	200,877.2	164,778.3
Developed Non-Producing	1,690.9	1,492.9	2,565.0	2,146.0	33,443.1	26,662.5
Undeveloped	4,290.0	3,654.9	3,325.4	2,705.2	22,314.6	18,028.6
TOTAL PROVED	68,458.2	61,534.1	40,101.3	35,630.6	256,634.9	209,469.4
PROBABLE	23,390.8	20,928.0	16,934.1	14,849.9	104,458.6	84,989.5
TOTAL PROVED PLUS PROBABLE	91,849.0	82,462.1	57,035.4	50,480.5	361,093.5	294,458.9

	RESERVES			
	NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT (BOE)	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED				
Developed Producing	6,937.6	5,221.3	137,105.3	119,850.1
Developed Non-Producing	776.2	562.2	10,606.0	8,644.9
Undeveloped	469.2	337.4	11,803.7	9,702.3
TOTAL PROVED	8,183.0	6,120.9	159,515.0	138,197.3
PROBABLE	3,561.7	2,586.0	61,296.4	52,528.8
TOTAL PROVED PLUS PROBABLE	11,744.7	8,706.9	220,811.4	190,726.1

Note:

(1) "Gross" refers to Harvest's working interest share before deduction of royalties and without including any royalty interests.
(2) "Net" refers to Harvest's working interest share after deduction of royalties.

The reserves attributable to Harvest's Hay River property, which is an area that produces medium gravity crude oil (average 24° API), are subject to a heavy oil royalty regime in British Columbia and would be required, under NI 51-101, to be classified as heavy oil for that reason. We have presented Hay River reserves as medium gravity crude in the following reserve tables as they would otherwise be classified in this fashion were it not for the lower rate royalty regime applied in British Columbia. If the Hay River reserves were included in the heavy crude oil category, it would increase the gross heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 13.46 mmboe, Proved Undeveloped: 1.85 mmboe, Total Proved: 15.31 mmboe, Probable: 4.18 mmboe and Proved plus Probable: 19.49 mmboe, and would increase the net heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 11.87 mmboe, Proved Undeveloped: 1.56mmboe, Total Proved: 13.42 mmboe, Probable: 3.70 mmboe, and Proved plus Probable: 17.13mmboe.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE DISCOUNTED BEFORE INCOME TAXES (1) 0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
PROVED					
Developed Producing	3,236,841	2,559,735	2,140,256	1,853,353	1,644,201
Developed Non-Producing	250,326	184,262	147,149	122,955	105,702
Undeveloped	205,704	144,761	103,033	72,950	50,470
TOTAL PROVED	3,692,870	2,888,758	2,390,438	2,049,258	1,800,373
PROBABLE	1,492,272	919,359	639,962	479,484	377,084
TOTAL PROVED PLUS PROBABLE	5,185,141	3,808,117	3,030,400	2,528,742	2,177,457

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2006
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($000)	ROYALTIES ($000)	OPERATING COSTS ($000)	DEVELOPMENT COSTS ($000)	WELL ABANDONMENT COSTS ($000)	FUTURE NET REVENUE BEFORE INCOME TAXES(1) ($000)
Proved Reserves	7,753,035	1,060,082	2,604,042	262,399	133,640	3,692,872
Proved Plus Probable Reserves	10,679,969	1,485,711	3,472,035	399,375	137,705	5,185,143

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2006
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000)
Proved Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	1,184,657
	Heavy Crude Oil (including solution gas and associated by-products)	609,021
	Associated and Non-Associated Natural Gas (including associated by-products)	596,760
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	1,472,494
	Heavy Crude Oil (including solution gas and associated by-products)	798,299
	Associated and Non-Associated Natural Gas (including associated by-products)	759,607

Reserves Data (Forecast Prices and Costs) – December 31, 2006

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2006
FORECAST PRICES AND COSTS

	RESERVES					
	LIGHT AND MEDIUM OIL(1)		HEAVY OIL(1)		NATURAL GAS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)
PROVED						
Developed Producing	62,161.4	56,070.8	33,626.6	30,245.0	202,709.3	166,370.3
Developed Non-Producing	1,689.7	1,491.8	2,563.0	2,139.4	33,559.4	26,768.6
Undeveloped	4,283.8	3,646.2	3,325.3	2,708.8	22,367.6	18,011.6
TOTAL PROVED	68,134.9	61,208.8	39,514.9	35,093.2	258,636.3	211,150.5
PROBABLE	23,230.4	20,773.8	16,725.0	14,694.1	104,913.2	85,368.0
TOTAL PROVED PLUS PROBABLE	91,365.3	81,982.6	56,239.9	49,787.3	363,549.5	296,518.5

	RESERVES			
	NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED				
Developed Producing	6,929.6	5,216.8	136,502.5	119,261.0
Developed Non-Producing	773.4	559.3	10,619.3	8,651.9
Undeveloped	467.8	335.1	11,804.8	9,692.0
TOTAL PROVED	8,170.8	6,111.2	158,926.6	137,604.9
PROBABLE	3,572.0	2,592.8	61,012.9	52,288.7
TOTAL PROVED PLUS PROBABLE	11,742.8	8,704.0	219,939.5	189,893.6

Note:

(1) The reserves attributable to Harvest's Hay River property, which is an area that produces medium gravity crude oil (average 24° API), are subject to a heavy oil royalty regime in British Columbia and would be required, under NI 51-101, to be classified as heavy oil for that reason. We have presented Hay River reserves as medium gravity crude in the following reserve tables as they would otherwise be classified in this fashion were it not for the lower rate royalty regime applied in British Columbia. If the Hay River reserves were included in the heavy crude oil category, it would increase the gross heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 13.5 mmboe, Proved Undeveloped: 1.8 mmboe, Total Proved: 15.3 mmboe, Probable: 4.2 mmboe and Proved plus Probable: 19.5 mmboe, and would increase the net heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 11.9 mmboe, Proved Undeveloped: 1.5 mmboe, Total Proved: 13.4 mmboe, Probable: 3.7 mmboe, and Proved plus Probable: 17.1 mmboe.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) (1) 0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
PROVED					
Developed Producing	3,449,433	2,718,718	2,272,096	1,968,696	1,748,327
Developed Non-Producing	320,589	224,008	174,696	144,360	123,440
Undeveloped	234,027	162,278	115,241	82,170	57,806
TOTAL PROVED	4,004,049	3,105,004	2,562,033	2,195,226	1,929,573
PROBABLE	1,794,897	1,052,984	714,852	528,477	412,606
TOTAL PROVED PLUS PROBABLE	5,798,946	4,157,988	3,276,885	2,723,703	2,342,179

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2006
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($000)	ROYALTIES ($000)	OPERATING COSTS ($000)	DEVELOPMENT COSTS ($000)	WELL ABANDONMENT COSTS ($000)	FUTURE NET REVENUE BEFORE INCOME TAXES(1) ($000)
Proved Reserves	8,823,530	1,211,908	3,140,311	289,154	181,108	4,004,049
Proved Plus Probable Reserves	12,569,475	1,739,988	4,390,977	440,395	199,169	5,798,946

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2006
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000)
Proved Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	1,192,675
	Heavy Crude Oil (including solution gas and associated by-products)	580,077
	Associated and Non-Associated Natural Gas (including associated by-products)	789,281
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	1,490,555
	Heavy Crude Oil (including solution gas and associated by-products)	766,017
	Associated and Non-Associated Natural Gas (including associated by-products)	1,020,313

Notes to Reserves Data Tables:

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

2. Columns may not add due to rounding.

3. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Reserve Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

4. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Reserve Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of these definitions are set forth below:

Reserve Categories

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

- analysis of drilling, geological, geophysical and engineering data;

- the use of established technology; and

- specified economic conditions.

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

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(b) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainly.

(c) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

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

Levels of Certainty for Reported Reserves

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

   (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

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

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

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

2. Forecast Prices and Costs – January 1, 2007

   Forecast prices and costs are those:

   (a) generally acceptable as being a reasonable outlook of the future; and

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

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the Reserve Report, based on McDaniel's then current forecasts at the date of the Report, were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of January 1, 2007
FORECAST PRICES AND COSTS

Year	OIL								
	WTI Crude Oil(1) ($US/ bbl)	Edmonton Light Crude Oil(2) ($Cdn/ bbl)	Alberta Heavy Crude Oil(3) ($Cdn/ bbl)	Alberta Bow River Hardisty Crude Oil(4) ($Cdn/ bbl)	Sask Cromer Medium Crude Oil(5) ($Cdn/ bbl)	NATURAL GAS Alberta AECO Spot Price ($Cdn/ GJ)	NATURAL GAS LIQUIDS Edmonton Cond. and Natural Gasolines ($Cdn/ bbl)	INFLATION RATES (6) (%/Year)	U.S./ CAN EXCHANGE RATE(7) ($US/$Cdn)
Forecast									
2007	62.50	70.80	39.20	49.30	62.20	6.85	72.30	2.0	0.870
2008	61.20	69.30	39.80	49.60	60.90	7.05	70.80	2.0	0.870
2009	59.80	67.70	40.20	49.80	59.40	7.40	69.30	2.0	0.870
2010	58.40	66.10	40.90	49.30	58.00	7.50	67.70	2.0	0.870
2011	56.80	64.20	39.70	47.90	56.40	7.70	65.80	2.0	0.870
2012	58.00	65.60	40.60	48.90	57.60	7.90	67.30	2.0	0.870
2013	59.10	66.80	41.30	49.80	58.70	8.10	68.50	2.0	0.870
2014	60.30	68.20	42.20	50.80	59.80	8.25	69.90	2.0	0.870
2015	61.50	69.50	43.00	51.80	61.00	8.45	71.30	2.0	0.870
2016	62.70	70.90	43.80	52.90	62.20	8.60	72.70	2.0	0.870
2017	64.00	72.30	44.80	54.00	63.50	8.75	74.10	2.0	0.870
2018	65.30	73.80	45.70	55.00	64.80	8.95	75.70	2.0	0.870
2019	66.60	75.30	46.60	56.10	66.10	9.10	77.20	2.0	0.870
2020	67.90	76.80	47.50	57.20	67.40	9.30	78.70	2.0	0.870
2021	69.30	78.30	48.50	58.40	68.80	9.50	80.30	2.0	0.870
There-after	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.870

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API/0.5% sulphur.
(2) Edmonton Light Sweet 40 degrees API, 0.3% sulphur.
(3) Bow River at Hardisty Alberta (Heavy stream).
(4) Heavy crude oil 12 degrees API at Hardisty Alberta (after deduction of blending costs to reach pipeline quality).
(5) Midale Cromer crude oil 29 degrees API, 2.0% sulphur.
(6) Inflation rates for forecasting prices and costs.
(7) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Operating Subsidiaries for the year ended December 31, 2006, were $6.76/mcf for natural gas, $58.54/bbl for natural gas liquids, $59.82/bbl for light/medium oil, and $46.14/bbl for heavy oil.

3. Constant Prices and Costs

Constant prices and costs are:

(a) the Operating Subsidiaries' prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

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

For the purposes of paragraph (a), the Operating Subsidiaries' prices are the posted prices for oil and the spot price for natural gas, after historical adjustments for transportation, gravity and other factors.

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

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2006
CONSTANT PRICES AND COSTS

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS	
Year	West Texas Intermediate (WTI)(1) ($US/bbl)	Edmonton Light Crude(2) ($Cdn/bbl)	Bow River Medium Crude at Hardisty(2) ($Cdn/bbl)	Cromer Medium Crude(2) ($Cdn/bbl)	Alberta Spot Natural Gas Price at Field Gate(4) ($Cdn/MMBtu)	Edmonton Reference Price NGL Mix(3) ($Cdn/bbl)	EXCHANGE RATE ($US/$Cdn)
2006	61.05	67.06	49.66	58.96	5.93	48.10	0.858

Notes:

(1) Based on December 31, 2006 NYMEX close.
(2) Based on Shell, Imperial, PetroCanada, EnCana, Suncor pricing at December 31, 2006.
(3) Based on historical price differentials and adjustments.
(4) Estimated from AECO December 31, 2006 price of $5.81/GJ.

4. Future Development Costs.

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

	Forecast Prices and Costs ($000)		Constant Prices and Costs ($000)	
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
2007	$144,648	$211,918	$141,141	$207,461
2008	$48,257	$97,840	$46,714	$94,251
2009	$11,116	$17,782	$10,637	$17,000
2010	$3,924	$4,612	$3,656	$4,282
2011	$3,312	$3,403	$3,006	$3,091
Thereafter	$77,897	$104,840	$57,245	$73,290
Total Undiscounted	$289,154	$440,395	$262,399	$399,375
Total Discounted at 10%	$217,263	$333,352	$205,853	$319,119

Future development costs will be funded through cash flow and the Trust's credit facilities currently available.

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

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

7. The extent and character of all factual data supplied to the Independent Reserve Engineering Evaluators were accepted by the Independent Reserve Engineering Evaluators as represented. No field inspection was conducted.

Reconciliations of Changes in Reserves and Future Net Revenue

RECONCILIATION OF
OPERATING SUBSIDIARIES NET RESERVES (After royalties)
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED NATURAL GAS		
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mmcf)	Net Probable (Mmcf)	Net Proved Plus Probable (Mmcf)
December 31, 2005	**38,556.3**	**12,612.3**	**51,168.6**	**28,619.6**	**12,442.4**	**41,062.0**	**52,841.3**	**15,190.7**	**68,032.0**
Extensions/ Improved Recovery	2,018.7	1,609.4	3,628.1	1,078.8	597.9	1,676.7	15,066.2	5,946.5	21,012.7
Technical Revisions	3,060.4	(745.9)	2,314.5	1,374.3	(1,622.9)	(248.6)	1,711.3	(27.9)	1,683.4
Discoveries							1,075.0	291.0	1,366.0
Acquisitions	25,614.6	7,265.1	32,879.7	7,905.3	3,251.2	11,156.5	173,392.5	65,954.1	239,346.6
Dispositions							(2,681.0)	(2,023.3)	(4,704.3)
Economic Factors	181.2	32.9	214.1	173.5	25.5	199.0	83.3	36.9	120.2
Production	(8,222.4)		(8,222.4)	(4,058.3)		(4,058.3)	(30,338.1)		(30,338.1)
December 31, 2006	**61,208.8**	**20,773.8**	**81,982.6**	**35,093.2**	**14,694.1**	**49,787.3**	**211,150.5**	**85,368.0**	**296,518.5**

	NATURAL GAS LIQUIDS			TOTAL (BOE)		
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MBOE)	Net Probable (MBOE)	Net Proved Plus Probable (MBOE)
December 31, 2005	**1,583.9**	**397.9**	**1,981.8**	**77,566.7**	**27,984.4**	**105,551.1**
Extensions/ Improved Recovery	225.6	108.4	334.0	5,834.1	3,306.8	9,140.8
Technical Revisions	474.9	222.5	697.9	5,194.8	(2,151.0)	3,043.8
Discoveries	0.8	1.3	2.1	180.0	49.8	229.8
Acquisitions	4,568.7	1,957.6	6,526.3	66,987.3	23,466.3	90,453.6
Dispositions	(98.5)	(95.4)	(193.9)	(545.3)	(432.7)	(978.3)
Economic Factors	1.1	0.5	1.6	369.7	65.1	434.8
Production	(645.3)		(645.3)	(17,982.4)		(17,982.4)
December 31, 2006	**6,111.2**	**2,592.8**	**8,704.0**	**137,604.9**	**52,288.7**	**189,893.6**

Note:

(1) Columns may not add due to rounding.

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

PERIOD AND FACTOR	2006 ($000)
Estimated Future Net Revenue at Beginning of Year	**$ 1,410,706**
Oil and Gas Sales During the Period Net of Royalties and Production Costs	(668,095)
Changes due to Prices	180,531
Actual Development Costs During the Period	367,582
Changes in Future Development Costs	(45,665)
Changes Resulting from Extensions, Infill Drilling and Improved Recovery	120,199
Changes Resulting from Discoveries	1,667
Changes Resulting from Acquisitions of Reserves	1,054,155
Changes Resulting from Dispositions of Reserves	(7,144)
Accretion of Discount	141,514
Other Significant Factors	(189,181)
Net Changes in Income Taxes	2,300
Changes Resulting from Technical Reserves Revisions Plus Effects of Timing	21,869
Estimated Future Net Revenue at End of Year	**$ 2,390,438**

Note:

(1) Table includes values from all Independent Reserve Engineering Evaluators.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook.

As at January 1, 2007, Harvest has a total of 22.4 mmboe of company interest reserves that are classified as proved non-producing. Of these non-producing reserves approximately 53% are undeveloped reserves. The balance are developed non-producing reserves which would be wells that are not currently producing and are eligible to be brought on production given current economics and production information. Substantially all of the undeveloped reserves are based on Harvest's current 2007 budget and long range development plans for the major assets noted elsewhere in this document. Approximately 80% of these reserves are expected to be developed within the next two years. The remaining undeveloped reserves will be developed over the next five years, in most cases due to processing facility capacity restrictions. The capital cost has been taken into account for these programs in the estimated future net revenue.

Significant Factors or Uncertainties

Information in this Annual Information Form contains forward-looking information and estimates with respect to Harvest. This information addresses future events and conditions, and as such involves risks and uncertainties that could cause actual results to differ materially from those contemplated by the information provided. These risks and uncertainties include but are not limited to factors intrinsic in domestic and international politics and economics, general industry conditions including the impact of environmental laws and regulations, imprecision of reserves estimates, fluctuations in commodity prices, interest rates or foreign exchange rates and stock market volatility. The information and opinions concerning the Trust's future outlook are based on information available at March 20, 2007.

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

Oil and Gas Properties and Wells

The following table sets forth the number of wells in which Harvest held a working interest as at December 31, 2006:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	3,295	2,642	1,389	1,118	1,653	739	567	346
British Columbia	128	128	133	132	14	5	11	3
Saskatchewan	1,119	951	512	459	25	15	10	5
Total	4,542	3,721	2,034	1,709	1,692	759	588	354

Notes:

(1) "Gross Wells" are wells in which Harvest has an interest (operating or non-operating).
(2) "Net Wells" are Harvest's interest share of the gross wells (operating or non-operating).

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which Harvest completed during its 2006 financial year:

	Exploratory Wells		**Development Wells**	
	Gross(1)	**Net(1)**	**Gross(1)**	**Net(1)**
Oil Wells	1	1.0	152	142.0
Gas Wells	8	3.7	76	31.6
Service Wells	-	-	10	9.5
Dry Holes	-	-	5	3.6
Total Wells	9	4.7	243	186.7

Note:

(1) "Gross Wells" are wells in which Harvest has an interest (operating or non-operating).
(2) "Net Wells" are Harvest's interest share of the gross wells (operating or non-operating).

For a discussion of Harvest's exploration and development activities refer to the "2007 Capital Expenditures Plan" section later in this Annual Information Form.

Properties with No Attributed Reserves

The following table sets out Harvest's undeveloped land holdings as at December 31, 2006.

	Undeveloped Acres	
	Gross	Net
Alberta	853,274	591,590
British Columbia	67,812	33,982
Saskatchewan	227,935	214,609
Total	1,149,021	840,181

	Undeveloped Acres for which rights expire within one year	
	Gross	Net
Alberta	243,841	151,002
British Columbia	1,280	480
Saskatchewan	33,507	31,884
Total	278,628	183,366

Production Estimates

The following table sets forth the volume of company working interest production estimated for 2007 as found in the reserve reports:

	2007 Production Forecast				
	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbl/d)	BOE (boe/d)
Proved Producing	22,804	16,546	93,324	2,728	57,632
Proved Developed Non-Producing	463	311	10,343	367	2,865
Proved Undeveloped	1,637	822	4,629	83	3,313
Total Proved	24,904	17,679	108,296	3,178	63,810
Total Probable	1,748	2,028	9,217	265	5,577
Total Proved Plus Probable	26,652	19,707	117,513	3,443	69,387

OTHER OIL AND NATURAL GAS INFORMATION

Oil and Natural Gas Properties

The Operating Subsidiaries' portfolio of Properties is discussed below. Reserve amounts discussed are gross reserves and are stated at December 31, 2006 based on forecast prices and cost assumptions. Although the Trust receives income from each of the Operating Subsidiaries pursuant to the NPI, interest and principal payments and trust and partnership distributions, all oil and natural gas operations and the management of the Trust are conducted by the Operating Subsidiaries.

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

Harvest's portfolio of significant properties is discussed below. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence levels as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

2006 Historical Production by Material Property

Material Property	Light, Medium and Heavy Crude Oil (bbl/d)	Natural gas (mcf/d)	NGL (bbl/d)	Average Daily Production (BOE/d)
Suffield	6,114	1,141	22	6,326
Hay River	5,498	-	-	5,498
Southeast Saskatchewan	5,229	179	97	5,356
Markerville / Sylvan Lake	299	22,002	602	4,568
Bellshill Lake	3,190	2,808	82	3,740
Hayter	3,630	246	9	3,680
Wainwright	2,838	186	4	2,873
Red Earth	2,405	234	61	2,505
Crossfield	6	10,181	531	2,234
Bashaw	1,582	1,959	98	2,007
Cavalier	496	4,050	26	1,197
Kindersley	999	719	32	1,151
Other	9,100	52,873	683	18,594
Total	**41,386**	**96,578**	**2,247**	**59,729**

Principal Producing Properties at December 31, 2006

Reserve amounts discussed are gross reserves and are stated at December 31, 2006 based on forecast prices and cost assumptions.

Suffield*:* Production from this region averaged 6,326 boe/d of primarily heavy oil in 2006, averaging 11-18° API from the Upper Mannville Glauconitic formation. Harvest has an average 99% working interest in this operated property. In 2006 Harvest invested $13 million to upgrade fluid handling capacities in Suffield, which will improve our fluid handling efficiency and will result in a reduction in operating costs. Harvest drilled 16 gross (16 net) infill horizontal wells in 2006 for a total capital cost of $20.7 million. Future development at Suffield may include step-out, extension and infill drilling at up to 45 identified locations. Pool optimization projects may target increased production and generate economic oil production with increased water cuts to outperform engineering reserve estimates. Harvest is also evaluating the use of enhanced oil recovery techniques to improve oil recovery from the Glauconitic reservoir.

Hay River*:* Hay River was acquired by Harvest on August 2, 2005 and in 2006 produced 5,498 BOE/d of medium gravity (24° API) crude oil. The Hay River medium production is priced at a discount to the Edmonton Light oil benchmark, contributing to stronger netbacks in this area when compared to other similar gravity crudes. Harvest has an average 100% working interest in this operated property. In the first quarter of 2006, we drilled 27 gross (27 net) wells for a net expenditure of $58 million. The development included multi-leg horizontal wells for production from the Bluesky formation, infill horizontal wells to assess the effectiveness of downspacing in this oil pool, water injection wells to maintain the reservoir pressure resulting in improved recovery factors, and pumping and facility upgrades to handle increased fluid production. Harvest also began construction of an all season access road to improve all season access to the Hay property. This will allow for maintenance and optimization activity to be undertaken year round further improving the efficiency of our operation.

Southeast Saskatchewan: Production from Southeast Saskatchewan averaged 5,356 boe/d of average 33° API crude oil in 2006, primarily produced from the Tilston and Souris Valley Formations. The Southeast Saskatchewan property includes Hazelwood, Moose Valley, Parkman, Whitebear, Kenosee and other minor properties. Harvest has an average 99% working interest in this operated property. In 2006 harvest drilled 37 gross (36.8 net) wells, primarily horizontal development and infill wells into defined pools, for a net capital expenditure of $38 million. At Kenosee, a stratigraphic evaluation well discovered a new pool that the company will develop using horizontal wells in 2007. Additional future development at Southeast Saskatchewan may include step-out and horizontal infill drilling of up to 50 locations to increase the recovery factor and accelerate production. Harvest believes further drilling opportunities are possible through the continued pooling of landowner interests to drill under-exploited areas. Harvest's extensive proprietary 3D seismic coverage offers control of the opportunity, and was a key component of our new pool discovery at Kenosee noted above.

Markerville/Sylvan Lake*:* The Markerville/Sylvan Lake area is located approximately 35 kilometres southwest of Red Deer, Alberta. Harvest is the operator for a majority of the production in the area and has a working interest varying from 50-90% in the majority of the area's wells. Markerville/Sylvan Lake averaged 4,568 boe/day (80% natural gas) for the 12 months ending December 31, 2006. The area offers multi-zone potential with two main producing horizons. The Pekisko formation, at a well depth of approximately 2,200 metres contains sweet natural gas along with associated liquids. The formation is developed using both vertical and horizontal wells. The Edmonton sands is a tight gas reservoir that contains sweet natural gas that is developed exclusively with vertical wells. In 2006, the company drilled or participated in 26 gross (11.5 net) wells for a total capital expenditure of $20.1 million in the area. A total of 4 gross (3.5 net) horizontal Pekisko wells were drilled with the remainder being primarily Edmonton Sands wells. Other minor zones of interest in this area are the Viking, Glauconitic and Ellerslie formations. In August 2006, Harvest acquired a new property at Sylvan Lake through the acquisition of Birchill. This light oil and solution gas property produces from Leduc reef formations, and Harvest has working interests ranging from 37.5% to 50%. Taking into account the August 1, effective date, production for the 12 months of 2006 averaged approximately 246 boe/d, with a significant drilling inventory to be pursued over the next 2 years.

Bellshill Lake*:* Harvest holds an average 98% working interest in this area, including a 99% working interest in the Bellshill Lake Ellerslie Unit, as well as working interests ranging from 6.5% to 100% in non-unit leases located next to the unit, all of which is operated by Harvest. Production consists of 26° API to 28° API oil produced from the Ellerslie, and Dina formations, and averaged 3,740 BOE/d in 2006 weighted 87% towards oil and liquids. The Unit and area comprises 707 gross wells of which 580 are producing oil wells. There are 32 injection and service wells, and 95 suspended oil wells. The majority of these wells are tied-in to one central facility consisting of an oil processing facility, a water injection plant and a gas processing facility. Oil is transported to market via Gibson's pipeline and the gas is sold on the spot market. In 2006 Harvest focused on reservoir optimization by commissioning an engineering study to assess improved recovery opportunities, primarily in the unit.

Hayter*:* Harvest acquired the Hayter property in November 2002. Production in 2006 at Hayter averaged approximately 3,680 boe/d of 14-15° API oil, producing from the Lower Cretaceous Cummings/Dina formation. Harvest has an average 94% working interest in this operated property. In 2006, Harvest drilled 16 gross (15.2 net) horizontal wells for a total expenditure of $9.4 million. Future development at Hayter may include additional infill and step-out drilling with over 30 identified locations, as well as enhanced oil recovery projects. A condensate injection pilot commenced in 2006, and we will continue to monitor performance through 2007. Operating expense reduction projects such as low pressure water disposal wells, horizontal disposal wells, and battery optimization are ongoing. In addition to cost reduction initiatives, Harvest believes it can capitalize on condensate blending opportunities to increase oil price realizations.

Wainwright: Harvest acquired the Wainwright properties in September 2004. Production in 2006 from these pools averaged approximately 2,873 boe/d of 22 - 24° API oil, produced from the Cretaceous Upper Mannville Sparky Formation. Harvest has an average 99% working interest in these operated properties. In 2006, Harvest drilled 14 gross (14 net) vertical infill wells into the Wainwright Sparky B pool, for a total expenditure of $7.7 million. The company also commissioned an engineering study to evaluate the feasibility of using a polymer based injection fluid to increase our sweep efficiencies and ultimate recoveries in this large oil pool. Development opportunities in 2007 may include additional infill and step-out drilling locations, as well as ongoing fluid handling optimization which Harvest believes will contribute to reduced operating expenses.

Red Earth*:* Production in 2006 from Red Earth averaged 2,505 boe/d of oil (98% oil) averaging 37 - 39° API from the Devonian Slave Point and Granite Wash Formations. The Red Earth area includes Loon Lake, EVI 1 and EVI 3.

Harvest has an average 80% working interest in this primarily operated area. In 2006, Harvest drilled 19 gross (16.8 net) wells for a total expenditure of $21.5 million. In addition, Harvest acquired approximately 30,000 net acres of undeveloped land including 27 sections (approximately 17,000 net acres) of oilsands rights proximate to our existing light oil production and pipeline infrastructure. Future development at Red Earth may include downspace drilling in the Slave Point G pool, as well as potential waterflood to increase the recovery factor and offset production decline. Harvest has an extensive seismic database in the Red Earth area which was instrumental in the discovery of a new oil pool in our EVI 3 area, and will assist our plans to infill drill our identified Granite Wash and Slave Point pools. The company is also planning to construct further processing facilities in our EVI 3 area to process production from the new wells and identified future drilling opportunities.

***Crossfield**:* Production in 2006 from this region was primarily natural gas (76%) with some liquids, and averaged approximately 2,234 boe/d from the Lower Cretaceous Basal Quartz formation. Harvest has an average 75% working interest in this operated property. Harvest is evaluating the potential for infill and step-out drilling, and field compression to increase the recovery factor as well as accelerate production from this tight gas formation.

***Bashaw**:* Harvest has a 93.3% working interest in the operated Bashaw D2G pool, a 90.6% working interest in the operated Bashaw D2L pool, and a 24.9% working interest in the non-operated D3A pool. This area produces oil and gas from the Nisku/Leduc reef formation at an average depth of 1,700m. Average production for 2006 was 2,007 boe/d with 84% weighted to oil and liquids on a boe basis. In 2006, Harvest drilled 5 gross (4.7 net) wells for a total expenditure of $7.0 million, to access incremental reserves located both in the core of the reef structure, as well as on the reef flank. Further potential exists in additional infill and step-out drilling as well an optimization of the existing waterflood patterns to improve recovery factors.

Cavalier: Production from this region in 2006 averaged 1,197 boe/d of light crude oil averaging 30-36° API (44% of boe production) and natural gas. Production is from the Upper Mannville Glauconitic formation at a depth of approximately 800m. Harvest has an average 96% working interest in this operated property. Future development at Cavalier may include waterflood/reservoir management and optimization, and infill drilling to increase the recovery factor and accelerate production.

Kindersley: The Kindersley Viking units are located approximately 10 miles east of the town of Kindersley Saskatchewan, and include the Eagle Lake Unit, North Dodsland Viking Unit No. 1, Smiley Dewar Unit, Whiteside Unit, and Whiteside East Unit in which Harvest holds working interests ranging from 11.2 to 100%. Production consists of 36° API crude oil from the Viking formation and, in 2006 averaged 1,151 BOE/d, (90% weighted to oil) of which the Eagle Lake Unit is the single largest contributor accounting for 75%. The crude oil is marketed via the Mid-Sask pipeline system. Solution gas is conserved and sold in the open market. Future potential includes significant downspacing opportunities as well as the implementation of an enhanced waterflood pilot to improve oil sweep efficiency and ultimate recovery factors from this reservoir.

2007 Capital Expenditure Plan

Harvest's expected total capital spending on its oil and natural gas properties for 2007 is expected to be approximately $295 million (after taking into account an incremental $20 million of the 2007 budgeted capital which was accelerated into 2006). The primary areas of focus for Harvest's capital program during 2007 are the following:

1. Hay River – drill 35 gross (35 net) multi-leg horizontal wells, infill horizontal wells, water injection wells and water source wells, continue construction of an all season access road, upgrade fluid handling and electric power delivery to the project for a net expenditure of $75 million Approximately $15 million of this expenditure was accelerated into 2006 due to favourable weather conditions.

2. Southeast Saskatchewan – drill 29 gross (29 net) wells for a net expenditure of $32 million.

3. Markerville/Sylvan Lake – drill 23 gross (11 net) wells for a net expenditure of $12 million.

4. Suffield – drill 12 gross (12 net) wells for a net expenditure of $16 million.

5. Red Earth – drill 26 gross (17.4 net) wells for a net expenditure of $26 million, as well as proceed with expansion of EVI 3 battery for $3 million.

6. Lloydminster / Hayter – drill 24 gross (22.6 net) horizontal wells for a net expenditure of $25 million.

7. Ferrier – drill 5 gross (2.6 net) wells and complete the construction of a gas processing facility for a net expenditure of $14.5 million.

Incremental Exploitation and Development Potential

Management of Harvest Operations has identified numerous development opportunities, many of which provide the potential for capital investment and incremental production beyond that identified in the Reserve Report. Opportunities being considered include:

1. Implementation or optimization of waterfloods in selected pools resulting in increased production and recovery;

2. Increasing water handling and water disposal capacity at key fields to add incremental oil volumes. This includes additional use of free water knock-outs and additional disposal wells;

3. De-bottlenecking existing fluid handling facilities and surface infrastructure;

4. Optimizing field oil cut management through the shut-in of select wells and increased total fluid from offset higher oil cut wells. Shut-in wells would be available for restart as oil cuts vary;

5. Uphole completions of bypassed or untested reserves in existing wellbores, including recompletion of existing shut-in wells to access undrained reserves;

6. Selected infill and step-out development drilling opportunities for various proven targets generally defined by 3D seismic;

7. Numerous exploratory opportunities defined by seismic from which value might be extracted by sale, farmout or joint venture; and

8. Opportunity to increase recovery factors in established pools using available and evolving enhanced recovery technologies.

Marketing Arrangements and Forward Contracts

Crude Oil and NGLs

Harvest's crude oil and NGLs production is marketed to a diverse portfolio of intermediaries and end users on 30 day continuously renewing contracts whose terms fluctuate with monthly spot market prices. Harvest received an average sales price, excluding the effects of commodity price risk contracts, of $59.82/bbl for its light and medium crude oil, $46.14/bbl for its heavy crude oil and $58.54/bbl for its NGLs for the year ended December 31, 2006 compared to $57.07/bbl for its light and medium crude oil, $39.43/bbl for its heavy crude oil and $52.40/bbl for its NGLs for the year ended December 31, 2005.

Natural Gas

Approximately 61% of Harvest's natural gas production is sold at the prevailing daily spot market price in Alberta, 32% is sold at the prevailing monthly spot price in Alberta with only 7% of its production dedicated to aggregator contracts which are contracted for the economic life of the reserves. Accordingly, Harvest's average sales price for natural gas will closely follow the average of the monthly and daily benchmark prices for natural gas deliver to the

Alberta spot market. Harvest received an average sales price, excluding the effects of commodity price risk contracts, of $6.76/mcf for its natural gas for the year ended December 31, 2006 compared to $9.05/mcf in 2005.

Forward Contracts

Harvest may use a variety of financial instruments and fixed price physical sales contracts to reduce its exposure to fluctuations in commodity prices and as a result, may be exposed to losses in the event of default by the counterparties to these contracts. This risk is managed by diversifying its contracts among a number of financially sound counterparties. For 2007, Harvest has entered into contracts to hedge approximately 60% of its expected 2007 gross crude oil production with an average floor price of approximately $56 per barrel. Harvest has also entered into contracts to hedge approximately 27% of its expected 2007 natural gas production using three way contracts.

A complete summary of Harvest's fixed price sales and purchase contracts along with its financial instruments use to manage commodity price risks can be found in Note 18 "Financial Instruments and Risk Management Contracts" to our audited consolidated financial statements for the year ended December 31, 2006 and under the heading "Price Risk Management Contracts" in our management discussion and analysis and results of operations for the year ended December 31, 2006 which have been filed on SEDAR at www.sedar.com. Both Note 18 of the audited consolidated financial statements for the year ended December 31, 2006 and the "Price Risk Management Contracts" section of our 2006 management's discussion and analysis are incorporated herein by reference.

Additional Information Concerning Abandonment and Reclamation Costs

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

Period	Abandonment & Reclamation costs (undiscounted and using a 2% inflation rate) ($000)	Abandonment & Reclamation costs (discounted at 10% using a 2% inflation rate) ($000)
Total as at December 31, 2006	818,224	145,446
Anticipated to be paid in 2007	10,970	9,973
Anticipated to be paid in 2008	6,800	5,620
Anticipated to be paid in 2009	6,825	5,128

The number of net wells for which the Independent Reserve Engineering Evaluators estimated that Harvest would incur abandonment and reclamation costs is 3,907 wells (Proved plus Probable).

Abandonment costs (excluding salvage values) associated only with wells were deducted by the Independent Reserve Engineering Evaluators in estimating future net revenue in the Reserve Report. The estimated future undiscounted expense related to facilities, pipelines and no reserve addition wells is $646.1 million ($92.9 million discounted at 10%). The nature of these expenses are not expected to change the anticipated costs for the next three years as they will not be incurred until the end of a field's reserve life profile.

Capital Expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to Harvest's activities for the year ended December 31, 2006:

Property costs	($millions)
Proved properties, including Viking and Birchill	2,467.1
Undeveloped properties	9.3
Total costs	2,476.4
Exploration costs	8.9
Development costs	358.7
Total Capital Expenditures	2,844.0

Potential Acquisitions

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

Tax Horizon

In our structure, taxable income from the Operating Subsidiaries is transferred to the Trust on an annual basis and taxable income of the Trust is transferred to our Unitholders with the payment of taxable distributions. The transfer of taxable income from the Operating Subsidiaries is primarily accomplished with the payment of the various net profits interests and the interest on the unsecured debt obligations owing to the Trust which are both deductible by the Operating Subsidiaries for income tax purposes. Accordingly, Harvest anticipates that there will be no corporate income tax liability payable by the Operating Subsidiaries for the foreseeable future. Further, the Trust Indenture currently requires the Trust to distribute its taxable income to Unitholders by December 31 in each fiscal year which ensures the Trust will not become liable for income taxes on undistributed income. See "Risk Factors – Risks Related to Harvest's Structure – Proposed Changes to the Tax Act".

Production History

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

	2006				
Average Daily Production Volumes (before the deduction of royalties)	Q1	Q2	Q3	Q4	Total
Light & Medium Oil (bbl/d) [1]	23,900	28,951	28,394	28,152	27,482
Heavy Oil (bbl/d)	15,182	13,037	13,919	13,967	13,904
Total Oil (bbl/d)	39,082	41,988	42,313	42,119	41,386
NGL (bbl/d)	1,709	2,016	2,595	2,649	2,247
Natural Gas(mcf/d)	73,337	96,848	103,618	112,006	96,578
Total Daily Production (BOE/d)	**53,014**	**60,145**	**62,178**	**63,436**	**59,729**

Total Sales Production:

Light and Medium Oil (bbl) (1)	2,161,789	2,645,330	2,623,037	2,600,774	10,030,930
Heavy Oil (bbl)	1,355,555	1,175,542	1,269,723	1,274,140	5,074,960
Total Oil (bbl)	3,517,344	3,820,872	3,892,760	3,874,914	15,105,890
NGL (bbl)	153,920	183,566	238,850	243,819	820,155
Natural Gas (mcf)	6,600,346	8,813,184	9,532,872	10,304,568	35,250,970
Total Production (BOE)	**4,771,322**	**5,473,302**	**5,720,422**	**5,836,161**	**21,801,207**

Average Sales Prices Received:

	2006				
	Q1	Q2	Q3	Q4	Total
Light & Medium oil ($/bbl) (1)	$53.06	$65.30	$ 66.64	$53.98	$59.82
Heavy Oil ($/bbl)	35.12	56.73	55.09	37.60	46.14
Total Oil ($/bbl)	46.09	62.64	62.84	48.55	55.22
Natural Gas ($/mcf)	8.10	6.59	5.75	6.99	6.76
NGL ($bbl)	56.69	63.35	61.57	53.17	58.54
BOE – 6:1	$ 47.01	$ 56.46	$ 54.92	$ 46.80	$ 51.40

Royalties Paid

	2006				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($000) (1)	$23,333	$26,862	$32,475	$21,454	$104,124
Heavy Oil ($000)	7,954	11,505	11,114	9,767	40,340
Natural gas & NGL's ($000)	11,828	13,540	10,773	19,504	55,645
Total BOE ($000)	$43,115	$51,907	$54,362	$50,725	$200,109
Light & Medium Oil ($/bbl) (1)	$10.79	$10.15	$12.38	$8.25	$10.38
Heavy Oil ($/bbl)	5.87	9.79	8.75	7.67	7.95
Natural gas & NGL's ($/boe)	9.43	8.19	5.89	9.94	8.31
Total BOE ($/boe)	$9.04	$9.48	$9.50	$8.69	$9.18

Operating Expenses(2)

	2006				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($000) (1)	$28,778	$33,787	$31,406	$33,278	$127,249
Heavy Oil ($000)	11,412	13,274	13,377	14,441	52,504
Natural gas & NGL's ($000)	9,427	13,274	13,377	15,069	51,147
Total BOE ($000)	$49,617	$60,335	$58,160	$62,788	$230,900
Light & Medium Oil ($/bbl) (1)	$13.31	$12.77	$11.97	$12.80	$12.69
Heavy Oil ($/bbl)	8.42	11.29	10.54	11.33	10.35
Natural gas & NGL's ($/BOE)	7.52	8.03	7.32	7.68	7.64
Total BOE ($/BOE)	$10.40	$11.02	$10.17	$10.76	$10.59

Netback Received[3]

	2006				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($/bbl) [1]	$28.96	$42.38	$42.29	$32.93	$36.75
Heavy Oil ($/bbl)	20.83	35.65	35.80	18.60	27.84
Natural gas & NGL's ($/BOE)	32.63	25.94	24.85	25.71	26.82
Total BOE ($/BOE)	$27.57	$35.96	$35.25	$27.35	$31.63

Notes:

(1) Medium oil production includes production from our Hay River property. The crude oil from this property has an average API of 24^{o} (medium grade); however, it benefits from a heavy oil royalty regime and therefore, would be classified as heavy oil according to NI 51-101.
(2) Includes impact of power hedge gains and losses.
(3) Before gains or losses on commodity derivatives.

Environment, Health and Safety Policies and Practices

Harvest has established internal environmental, health and safety guidelines and systems to ensure the health and safety of its employees, contractors and neighbouring residents and to ensure compliance with environmental laws, rules and regulations. These systems require Harvest to regularly conduct emergency response planning exercises to ensure its plans are effective and to inspect suspended wells, abandoned wells as well as site restoration plans and activities. Harvest's Manager of Environment, Health and Safety is responsible to monitor regulatory requirements and when required, implement appropriate compliance procedures and to cause our operations practices to be carried out in accordance with the applicable environmental requirements with adequate safety precautions. The Reserves, Safety and Environmental Committee of Harvest Operations' Board of Directors regularly review the results of these internal programs. Although the existence of these controls cannot guarantee total compliance with environmental laws, rules and regulations, Harvest believes that its operations are in material compliance with the applicable requirement.

In 2006, Harvest invested $9.2 million in the reclamation and restoration of existing wellsites as part of our overall commitment to restore the surface land to its original state. As a result of our efforts over the past few years, we were able to submit 50 reclamation certificate applications during the year which will ultimately result in the elimination of both our administrative as well as financial obligation to the surface owners. In addition, we completed the downhole abandonment of 19 wells.

In 2006 we received approval to inject waste gas from our Hayter field back into the reservoir rather than flaring this gas into the atmosphere. This approval will not only eliminate approximately 350 E3m3 (12.3 mmscf) of waste gases from our environment, but will also provide further pressure support in our pursuit of enhancing the oil recovery from our large oil pools.

Impact of Volatility in Commodity Prices

Harvest's operational results and financial condition will be dependent on the prices received for petroleum and natural gas production. Petroleum and natural gas prices 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 and natural gas regions. Any decline in petroleum and natural gas prices could have an adverse effect on Harvest's financial condition. Harvest mitigates such price risk through closely monitoring the various commodity markets and establishing commodity price risk management programs, as deemed necessary, to provide stability to its cash flows.

A summary of financial and physical contracts in respect of price risk management activities can be found in Note 18 to Harvest's consolidated financial statements for the year ended December 31, 2006 and under the heading "Risk Management Contracts" in Harvest's management discussion and analysis for the year ended December 31, 2006 both of which have been filed on SEDAR at www.sedar.com. Both Note 18 of Harvest's audited consolidated financial statements for the year ended December 31, 2006 and the "Risk Management Contracts" discussion in Harvest's management discussion and analysis for the year ended December 31, 2006 are incorporated herein by this reference.

Industry Conditions

The petroleum and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of petroleum and natural gas by agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the petroleum and gas industry. It is not expected that any of these controls or regulations will affect Harvest's operations in a manner materially different than they would affect other petroleum and natural gas entities of similar size. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the petroleum and natural gas industry.

Pricing and Marketing – Petroleum, Natural Gas and Associated Products

In the provinces of Alberta, British Columbia and Saskatchewan, petroleum, natural gas and associated products are generally sold at market index based prices. These indices are generated at various sales points depending on the commodity and are reflective of the current value of the commodity adjusted for quality and locational differentials. While these indices tend to track industry reference prices (i.e. West Texas Intermediate crude oil at Cushing, Oklahoma or natural gas at Henry Hub, Louisiana), some variances can occur due to specific supply-demand imbalances. These differentials can change on a monthly or daily basis depending on the supply-demand fundamental at each location as well as other non-related changes such as the value of the Canadian dollar and the cost of transporting the commodity to the pricing point of the particular index.

The producers of crude oil are entitled to negotiate sales contracts directly with purchasers, with the result that the market determines the price of crude oil. Crude oil prices are primarily based on worldwide supply and demand. The specific price depends in part on quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance and other contractual terms. Crude oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any crude 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 license from the NEB and the issuance of such license requires the approval of the Governor in Council.

The price of natural gas 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 other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 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 license from the NEB and the issuance of such license requires the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Pipeline Capacity

Although pipeline expansions are ongoing, pipeline capacity is an important consideration and may impact the oil and natural gas industry by limiting the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, United States of America and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period or in such other representative period as the parties may agree); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements provided, in the case of export-price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

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 and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur 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, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery 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, net profits interests or net carried interests.

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

In November, 2003 the Tax Act was amended to provide the following initiatives applicable to the oil and gas industry to be phased in over a five year period: (i) a reduction of the federal statutory corporate income tax rate on income earned from resource activities from 28% to 21%, and (ii) a deduction for federal income tax purposes of actual provincial and other Crown royalties and mining taxes paid coincident with the elimination of the 25% resource allowance. In addition, the percentage of Alberta Royalty Tax Credit required to be included in federal taxable income was 12.5% in 2004, 17.5% in 2005 and 32.5% in 2006; and will be 50% in 2007; 60% in 2008; 70% in 2009; 80% in 2010; 90% in 2011, and 100% in 2012 and beyond.

Alberta

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing crude oil reserves in Alberta. Crude 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 reactivated well that has not produced for: (i) a 12-month period, if resuming production in October, November or December of 1992 or January, 1993; or (ii) a 24 month period, if resuming production in February 1993 or later. 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). Crude oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

Crude oil royalty rates vary from province to province. In Alberta, oil royalty rates vary between 10% and 35% for crude oil and 10% and 30% for new oil. New oil is applicable to oil pools discovered after March 31, 1974 and prior to October 1, 1992. The Alberta government introduced the Third Tier Royalty with a base rate of 10% and a rate cap of 25% for crude oil pools discovered after September 30, 1992.

Effective January 1, 1994, the calculation and payment of natural gas royalties became subject to a simplified process. 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 continues to be eligible for a royalty exemption for a period of 12 months, or such later time that the value of the exempted royalty quantity equals 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.

Alberta's current royalty system for oil sands, introduced in 1997 and expiring June 30, 2007, is designed to support the development of the oil sands industry. An initial royalty of 1% of the quantity of oil sands product that is recovered and delivered to the royalty calculation point is payable until the project has recovered specified allowed costs, including certain exploration and development costs, operating costs, a return allowance and royalties paid to the Crown. Subsequent to such recovery, the royalty payable is the greater of the aforesaid 1% royalty and 25% of the net revenue from an oil sands project. The foregoing royalty will approximate a 1% royalty on gross revenue before payout and a 25% royalty on net revenue after payout.

For periods prior to January 1, 2007, a producer of crude oil or natural gas in Alberta was entitled to a credit on qualified oil and natural gas production against the royalties payable to the Crown by virtue of the Alberta Royalty Tax Credit ("**ARTC**") program. The ARTC rate is based on a price sensitive formula and the ARTC rate varies between 75% at prices at and below $100 per m3 and 25% at prices at and above $210 per m3 in respect of royalties paid on eligible producing properties. 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 a corporation claiming maximum entitlement to ARTC will generally not be eligible for ARTC. For periods subsequent to December 31, 2006, the ARTC program has been repealed.

British Columbia

Producers of crude oil and natural gas in the Province of British Columbia are also required to pay annual rental payments in respect of the Crown leases and royalties and freehold production taxes in respect of crude oil and gas produced from Crown and freehold lands, respectively. The amount payable as a royalty in respect of crude oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil) between October 31, 1975 and June 1, 1998 (new oil) or after June 1, 1998 (third-tier oil). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the amount obtained by the producer, and a prescribed minimum price. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for the province of British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("**Strategy**"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties, and regulatory reduction and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits of up to $30 million annually towards the construction, upgrading and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry.

- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of crude oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil" or "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas" and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic meters in a month.

A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002 was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002 will receive the "fourth tier" royalty/tax rates and new incentive volumes.

On March 23, 2005, the Government of Saskatchewan passed legislation to subject trusts to their Corporation Capital Tax Resource Surcharge (the "**Resource Surcharge**") with an effective date of April 1, 2005. The Resource Surcharge is calculated based on the applicable oil and natural gas revenues earned in Saskatchewan at a rate of 3.6% for wells drilled prior to October 1, 2002 and at a rate of 2% for wells drilled on or after October 1, 2002. Effective July 1, 2006, the Resource Surcharge rates were reduced from 3.6% to 3.3% for wells drilled prior to

October 1, 2002 and from 2% to 1.85% for wells drilled on or after October 1, 2002 and effective July 1, 2007, the Resource Surcharge rates were reduced from 3.3% to 3.1% for wells drilled prior to October 1, 2002 and from 1.85% to 1.75% for wells drilled on or after October 1, 2002. And subsequent to July 1, 2008, the Resource Surcharge rates were reduced from 3.1% to 3.0% for wells drilled prior to October 1, 2002 and from 1.75% to 1.70% for wells drilled on or after October 1, 2002. Prior to this legislation, the Resource Surcharge did not apply to trusts to earned oil and gas revenues in Saskatchewan.

Land Tenure

Crude oil and natural gas located in western Canada 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 2 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 petroleum and natural gas industry is subject to environmental regulation pursuant to a variety of international conventions and Canadian federal, provincial and municipal laws, regulations, and guidelines. Such regulation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain petroleum and gas industry operations. In addition, such regulation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such regulation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**AEPEA**"), which came into force on September 1, 1993 and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The AEPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations and significantly increase penalties. Harvest is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment and will be taking such steps as required to ensure compliance with the AEPEA and similar legislation in other jurisdictions in which it operates. Harvest believes that it is in material compliance with applicable environmental laws and regulations and also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

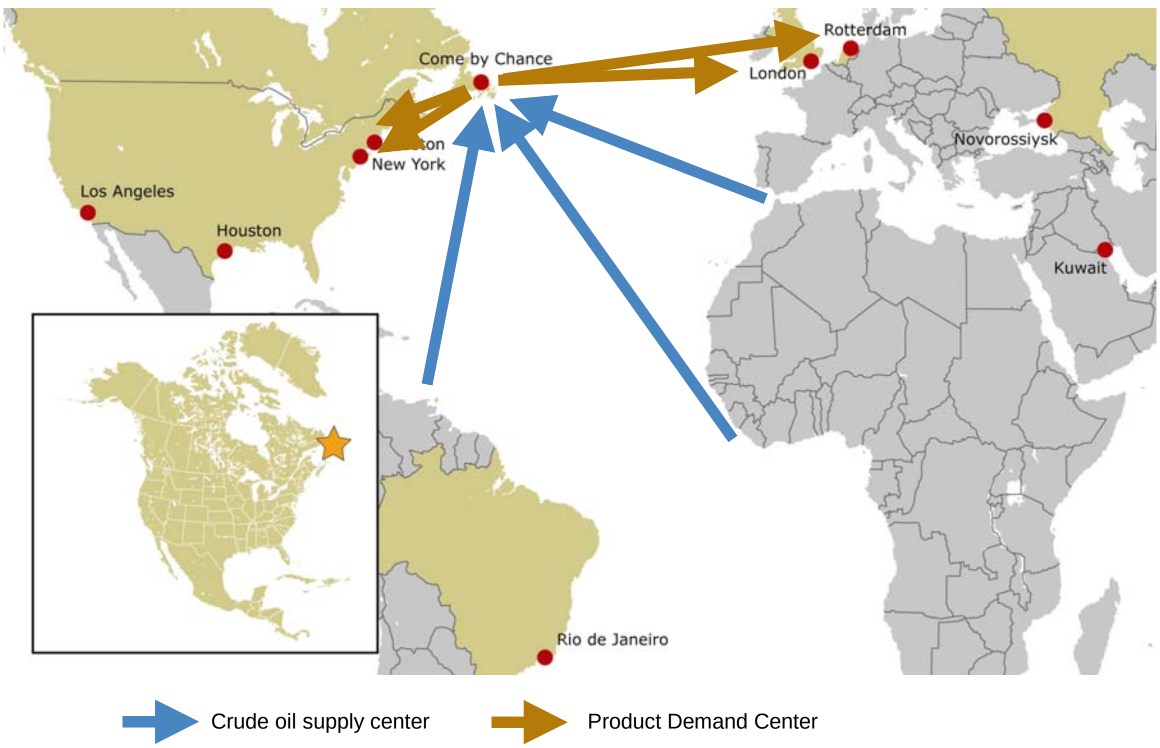
British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. In April 2005, Environment Canada released "Project Green", a working paper giving early indications of how implementation was to be achieved. Large Final Emitters ("**LFEs**"), being 700 of Canada's largest emitters, will receive a specific reduction target of 45 megatonnes, and will have the opportunity to purchase domestic offset and technology credits. The exact mechanism for operating in the domestic credit market has yet to be revealed, and the prospect of non-LFE enterprise participating in that market to any great extent is uncertain. Various incentive funds have also been established to provide seed funding for the purchase of experimental technologies, encourage investment in alternative energy sources, and acquire credits from the domestic and international markets for re-sale to Canadian enterprise.

Environment Canada, in August 2005, released consultation papers for the management of a system of greenhouse gas offsets in the form of tradable and bankable credits. The credits are created by enterprise, individuals, or municipal government through the implementation of projects registered with the to-be-created offset authority. Standards for quantifying greenhouse gas reductions were also proposed in the consultation paper.

PETROLEUM REFINING AND MARKETING BUSINESS

North Atlantic is an independent crude oil refiner that owns and operates a medium gravity, sour crude oil hydrocracking refinery located in the Province of Newfoundland and Labrador with a capacity of 115,000 barrels per stream day. The Refinery's feedstocks are delivered by tanker primarily from the Middle East, Russia and Latin America. The Refinery produces high quality gasoline, ultra low sulphur diesel, jet fuel and furnace oil with a residual of heavy fuel oil. Approximately 10% of North Atlantic's refined products are sold in the Province of Newfoundland and Labrador while approximately 90% are sold in the U.S. east coast markets such as Boston and New York City. North Atlantic enjoys a significant transportation advantage as it operates a deep water docking facility and has approximately seven million barrels of tankage including six 575,000 barrel crude tanks enabling the receipt of crude oil transported on very large crude carriers which typically result in significantly lower per barrel transportation charges. The following map highlights the North Atlantic transportation advantage.



Distance from Come by Chance, Newfoundland, Canada to:	Sailing Days
Boston, U.S.	3
New York, U.S.	3
London, U.K.	7
Rotterdam, Netherlands	7
Houston, U.S.	8
Novorosslysk, Russia	14
Rio de Janeiro, Brazil	14
Los Angeles, U.S.	18
Kuwait City, Kuwait	24

North Atlantic's assets include dock facilities for off-loading crude oil feedstock and for loading refined products. These facilities include two berths connected to the onshore tank farm by an 800 foot causeway and a 2,800 foot approach trestle combination. The dock facilities handle approximately 220 vessels each year with North Atlantic owning and operating two tugboats to assist with berthing and unberthing tankers. One tugboat, acquired in 1999, is equipped with firefighting capability while the other is equipped with oil spill response capability.

Through its marketing division, North Atlantic operates a petroleum marketing and distribution business in the Province of Newfoundland and Labrador with average daily sales over 9,800 barrels. The North Atlantic brand has been positioned in the Newfoundland marketplace as a local company with its retail gasoline business operating 66 retail gas stations and 3 cardlock locations capturing a market share of approximately 15%. In addition to its retail operations, North Atlantic has a commercial, wholesale and home heating business.

Brief History

The construction of the Refinery commenced in 1971 with the crude oil distillation unit commissioned in late 1973 and most other process units started-up in 1974. The Refinery was shut down two years later as the owner filed for bankruptcy protection during the oil price shock. In 1980, Petro-Canada purchased the Refinery but did not operate it, and in late 1986, sold the Refinery to a private company. From 1986 through 1994, the new owner invested approximately $132 million in the Refinery including the construction of a new hydrogen furnace. On April 24, 1994, the Refinery experienced a fire at the vacuum tower and, as a consequence, the entire facility was again shut down as the owner was unable to finance the restoration of the Refinery.

The Vitol Refining Group B.V. acquired the Refinery in August 1994 and commenced a major restoration and successfully commissioned the Refinery in late 1994. Since then, more than US$400 million was invested to maintain, upgrade and expand the facility. These investments significantly improved the Refinery's operating performance in terms of refinery throughput, reliability, saleable yield, product quality, safety and environmental performance. In 2006, the Refinery averaged 94,800 barrels per stream day, up slightly from 93,900 barrels per stream day in the prior year. Both production years were impacted by planned maintenance turnarounds, with a saleable yield of 95.1% while its safety performance was 0.84 lost time accidents per 200,000 man hours. Since 1997, the Refinery's sulphur dioxide emissions have also been reduced by 63% despite a significant increase in throughput.

Refinery Operations

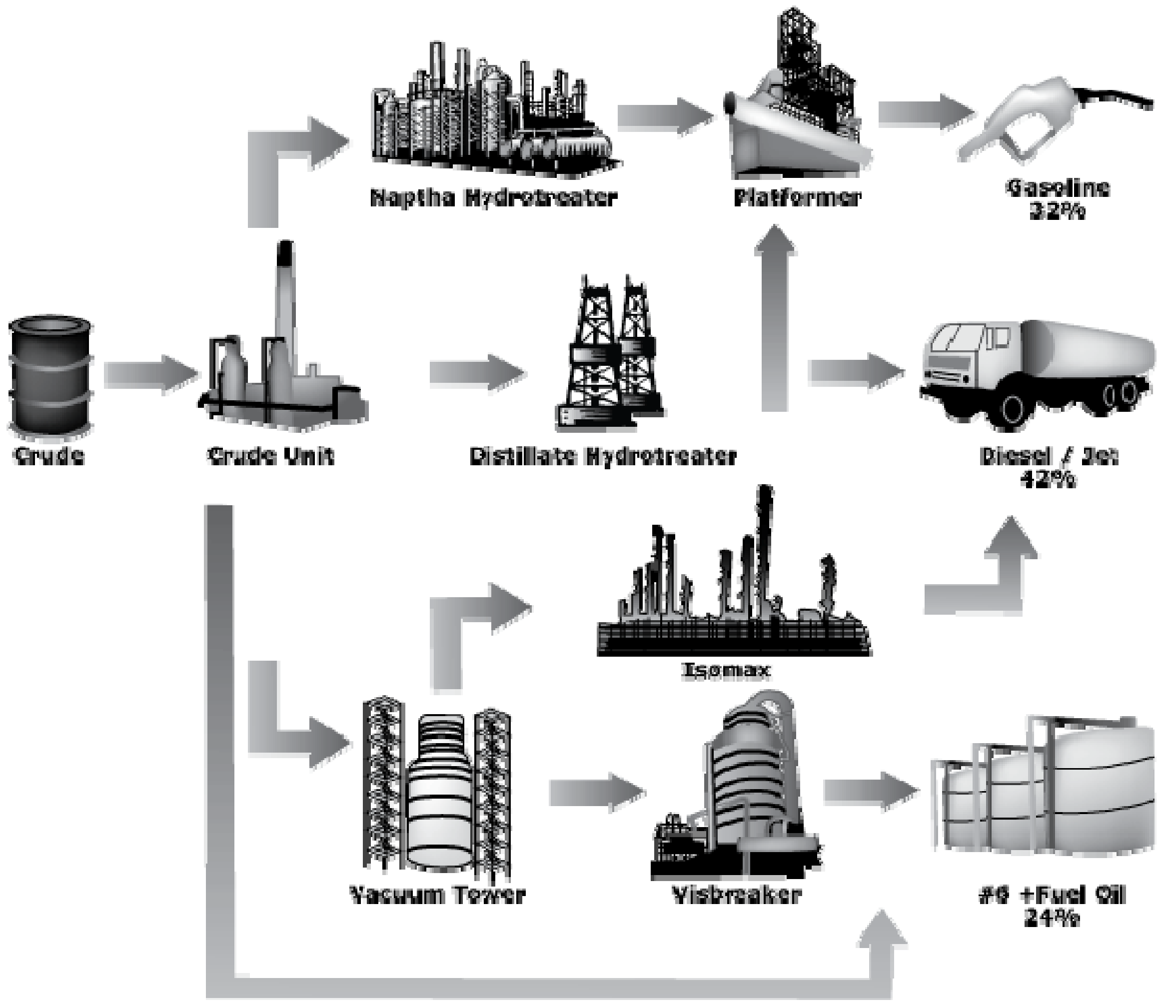
Summary of Refinery Inputs

Crude oil and other feedstocks are delivered to the Refinery via vessels capable of carrying over 2 million barrels of crude oil per vessel. Normally, there is approximately 20 days of crude oil feedstock in tankage at the Refinery to mitigate the effects of any delivery disruptions. Over the past three years, the source of the crude oil feedstock has been as follows:

	From October 19, 2006 to December 31, 2006	2006	2005	2004
			(000's of bbls)	
Middle East	5,372	25,535	23,672	26,884
Russia	-	1,148	5,596	6,421
Latin America	524	4,258	2,686	-
Other	446	3,667	2,324	3,445
Total Feedstock	**6,342**	**34,608**	**34,278**	**36,750**

Overview of Crude Oil Processing

The following is a summary of the primary process flow of North Atlantic's Refinery including a brief description of the process and purpose of the identified processing units. This summary excludes the various utility plants as well as a number of secondary units that add relatively small incremental volume enhancements to higher valued products from the diesel and fuel oil streams.



Crude & Vacuum Distillation Unit

Crude oil from tankage is heated and processed in the crude unit for primary distillation or separation into various components. The crude oil is first processed in the crude distillation tower where the crude is fractionated into the following streams:

- Liquid petroleum gas products such as fuel gas, propane, and butane;
- Lighter liquid products (naphtha) which are further upgraded in the naphtha hydrotreater and platformer for the production of gasoline;
- Distillate materials (kerosene and diesel) which are produced from the middle of the distillation tower. The kerosene goes to either jet fuel blending, the distillate hydrotreater for Ultra Low Sulphur Diesel ("**ULSD**") production, or No. 6 fuel blending. The crude diesel goes to the distillate hydrotreater for ULSD production;
- The material remaining in the bottom of the crude distillation tower ("**bottom ends**") is sent to the vacuum tower for further separation.

- The vacuum tower operates at less than atmospheric pressure and further fractionates the bottom ends. Vacuum gas-oil from the vacuum tower is then routed to the Isomax unit to be upgraded primarily into naphtha, kerosene and ultra-low sulphur diesel. The residual vacuum tower bottoms stream is routed to the visbreaker.

Naphtha Hydrotreater and Platformer and Platformate Hydrogenation Units

The naphtha hydrotreater, uses hydrogen and a catalyst to remove sulphur and nitrogen contaminants from the naphtha to enable it to be used as platformer feed. The platformer then converts the naphtha into high octane gasoline for use in gasoline blending. A portion of the gasoline is further processed in the platformate hydrogenation unit ("**PHU**"). The PHU enables the refinery to meet the low benzene level requirements of reformulated gasoline.

Distillate Hydrotreater

The distillate hydrotreater operates at high pressure and uses hydrogen over a catalyst bed to remove nearly all of sulphur and nitrogen from the middle distillates for the production of ultra-low sulphur diesel.

Isomax HydroCracker Unit

The Isomax unit (also known as a hydrocracker) uses extremely high heat and pressure to upgrade the heavy gas-oil portions through the injection of hydrogen. This process removes contaminants and produces naphtha for gasoline blending and platformer feed, ultra-low sulphur diesel and jet fuel. The bottom ends from the Isomax unit are also used as a valuable lubricant feedstock.

Visbreaker

The vacuum tower bottoms, an asphalt-like product, are processed in the visbreaker. The visbreaker uses high temperature to crack long chain molecules thereby reducing cutter (kerosene) requirements for No 6 oil blending.

Storage and Shipping

Crude oil feedstock and refined products from the various processing units are temporarily stored in designated tanks. North Atlantic has storage capacity for approximately seven million barrels of crude oil and refined product. This storage capacity is typically allocated approximately 50% to crude oil feedstock and 50% to refined product outputs. Refined products are ultimately shipped for delivery to the United States Atlantic Coast market, including Boston and New York City. These markets typically consume approximately 90% of the Refinery's production. The vessels delivering refined products typically have capacity for approximately 330,000 barrels and are limited to transporting one or two products.

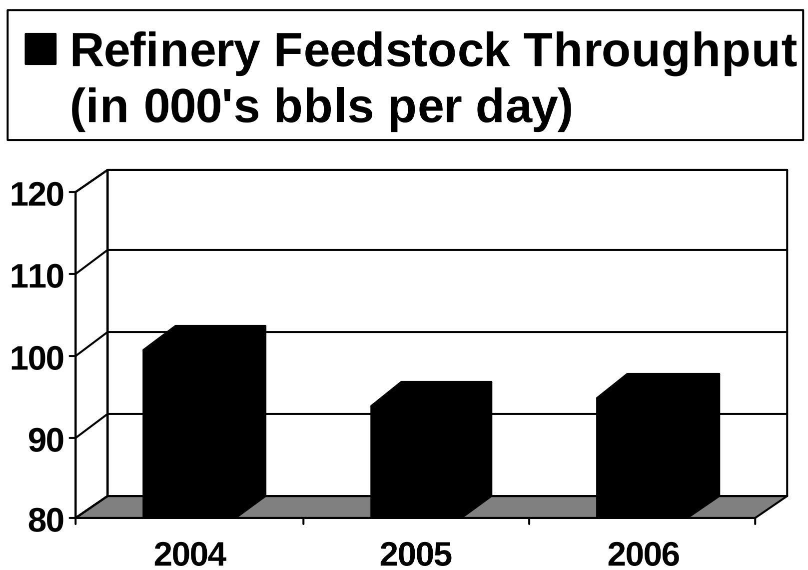
Summary of Refined Products

Over the past three years, the Refinery has produced the following refined products with a total yield of approximately 95% of feedstock as the impact of adding hydrogen swells the barrels offsetting the fuel used by the Refinery:

	From October 19, 2006 to December 31, 2006	2006	2005	2004
			(000's of bbls)	
Gasoline and related products	1,875	11,434	12,571	15,349
Ultra low sulphur diesel	2,624	14,270	13,736	13,723
Heavy fuel oil	1,752	9,633	9,444	9,582
Total Products	6,251	35,337	35,751	38,654
Total Yield (as a % of feedstock)	99%	102%	104%	105%

Operations Reliability

Improving the reliability of the Refinery has been a major focus for North Atlantic accomplished with significant capital expenditures and a change in maintenance philosophy. North Atlantic's maintenance philosophy has evolved to one that emphasizes long term solutions to reliability issues through the conduct of rigorous analyses regarding the root cause of reliability issues. Of particular note, North Atlantic developed on advanced Equipment Integrity Program whereby remaining equipment life calculations are utilized to determine equipment turnaround schedules and ensuring that equipment is repaired or replaced before failure occurs. A summary of North Atlantic's Refinery level of throughput for the period 2004 to 2006 is as follows:



The decline in 2004 was due to a planned minor turnaround of the crude oil distillation tower, and in 2005 was due to a planned major turnaround outage to maintain common facilities.

Currently, North Atlantic has the opportunity and intends to consider opportunities to grow its business through the reconfiguration and enhancement of its Refinery assets with a suite of expansion or debottlenecking projects plus a coker project or a visbreaker project for bottoms upgrading.

Supply and Offtake Agreement

Concurrent with the acquisition of North Atlantic by Harvest, North Atlantic entered into the Supply and Offtake Agreement with Vitol Refining S.A. The Supply and Offtake Agreement provides that the ownership of substantially all crude oil feedstock and refined product inventory at the Refinery be retained by Vitol Refining S.A. and that during the term of the Supply and Offtake Agreement, Vitol Refining S.A. will be granted the right and obligation to provide crude oil feedstock for delivery to the Refinery as well as the right and obligation to purchase all refined products produced by the Refinery. The Supply and Offtake Agreement also provides that Vitol Refining S.A. will also receive a time value of money amount (the "**TVM**") reflecting the cost of financing the crude oil feedstock and sale of refined products as the Supply and Offtake Agreement requires that Vitol Refining S.A. retain ownership of the crude oil feedstock until delivered through the inlet flange to the Refinery as well as immediately take title to the refined products as they are delivered by the Refinery through the inlet flange to designated storage tanks. Further, the Supply and Offtake Agreement provides North Atlantic with the opportunity to share the incremental profits and losses resulting from the sale of products beyond the U.S. East Coast markets.

Pursuant to the Supply and Offtake Agreement, North Atlantic, in consultation with Vitol Refining S.A., will request a certain slate of crude oil feedstocks and Vitol Refining S.A will be obligated to provide the crude oil feedstocks in accordance with the request. The Supply and Offtake Agreement includes a crude oil feedstock transfer pricing formula that aggregates the pricing formula for the crude oil purchased as correlated to published future contract settlement prices, the cost of transportation from the source of supply to the Refinery and the settlement cost or proceeds for related price risk management contracts plus a fee of US$0.08 per barrel. The purpose of the price risk management contracts is to convert the fixed price of crude oil feedstock purchases to floating prices for the period from the purchase date through to the date the refined products are sold to allow "matching" of crude oil feedstock purchases to refined product sales thereby mitigating the gross margin risk between the time crude oil feedstocks are purchased and the sale of the refined products.

The Supply and Offtake Agreement requires that Vitol Refining S.A. purchase and lift all refined products produced by the Refinery, except for certain excluded refined products to be marketed by North Atlantic in the local Newfoundland market, and provides a product purchase pricing formula that aggregates a deemed price based on the current Boston and New York City markets less the deemed costs of transportation, insurance, port fees, inspection charges and similar costs deemed to be incurred by Vitol Refining S.A., plus the TVM component. The TVM component recognizes the cost of financing the refined products for the time deemed to deliver the refined product from the Refinery through to the date Vitol Refining S.A. is deemed to have received payment for the sale.

The TVM component of the Supply and Offtake Agreement in respect of crude oil feedstock and the sale of refined products will reflect an effective interest rate of 350 basis points over the London Inter Bank Offer Rate ("**Libor**") and will be included in the weekly settlement of all amounts owing.

The Supply and Offtake Agreement requires that Vitol Refining S.A provide North Atlantic with notice if it plans to sell product outside the U.S. East Coast market which will entitle North Atlantic to the right, but not the obligation, to share in the incremental profit or loss from such sales.

The Supply and Offtake Agreement may be terminated by either party at the end of an initial two year term, and at any time thereafter, by providing notice of termination no later than six months prior to the desired termination date or if the Refinery is sold in an arms length transaction, upon 30 days notice prior to the desired termination date. Further, the Supply and Offtake Agreement may be terminated upon the continuation for more than 180 days of a delay in performance due to force majeure but prior to the recommencing of performance. After an initial 12 month period, Vitol Refining S.A.'s exclusive right and obligation to provide crude oil feedstock to the Refinery may be terminated by either party by providing six months notice. Upon termination of the entire agreement or the right and obligation to provide crude oil feedstock, North Atlantic will be required to purchase the related crude oil feedstock and refined product inventory or crude oil feedstock, respectively, at the prevailing market prices.

Vitol Refining S.A. is an indirect wholly-owned subsidiary of the Vitol Refining Group B.V., a privately owned worldwide marketer of crude oil providing oil trading and marketing services to upstream producers through to downstream retailers of petroleum products. In 2005, the Vitol Group handled over US$80 billion of crude oil, fuel oil, gasoline and related products. With headquarters in Rotterdam, the Netherlands and Geneva, Switzerland, the

Vitol Group has trading entities in Houston, London, Bahrain and Singapore which provide 24 hour coverage of all the world's oil markets. In the past two years, the Vitol Group has traded over 85 million tonnes of crude oil and is a major lifter of non-equity crude oil from Nigeria, the Middle and Far East, Russia and the Caspian. In the crude oil sector, the Vitol Group has developed a worldwide reputation as a reliable business partner. In addition, the Vitol Group is one of the largest independent gasoline traders in the world with over 23 million tonnes handled over the past four years.

Marketing Division

North Atlantic's marketing division (the "**Marketing Division**") is headquartered in St. John's, Newfoundland and is comprised of five business segments: retail, home heating, commercial, wholesale and bunkers described as follows:

Retail Gasoline

North Atlantic operates 66 retail gasoline stations and 3 commercial cardlock locations with 39 locations branded as "North Atlantic" and 16 locations branded as "Home Town" (a secondary brand for small market areas) with the remaining 11 locations unbranded. Most locations include a convenience store which is independently operated. In 2005, the volume of gasoline and diesel sold at these retail locations represented a market share of approximately 15% of the Newfoundland market. The major competitors in the Newfoundland market are Irving Oil, Imperial Oil and Ultramar.

Home Heating Business

North Atlantic delivers furnace oil and propane to approximately 20,000 residential heating and commercial customers throughout Newfoundland with about 90% of the demand for furnace oil, 9% for propane and 1% for kerosene. North Atlantic is a full service residential heating supplier providing a furnace parts maintenance replacement program, emergency burner service and heating system installations from five "Home Heating" stores. North Atlantic's installation and emergency burner service is provided by independent contractors, as is its bulk hauling.

Commercial Business

North Atlantic delivers distillates, jet fuel, propane and No. 6 fuel oil to commercial heating, marine, aviation, trucking and construction industries from seven storage terminals.

Wholesale Business

North Atlantic provides distillates, jet fuel and propane to a number of wholesale customers from both its wharf and truck rack facilities with current volumes averaging approximately 3,300 barrels per day.

Bunker Business

North Atlantic sells bunkers to crude oil and refined product vessels at its wharf facilities.

Overview of Management Structure

The management structure of North Atlantic consists of a two man executive team (a "**President, Refinery Manager**" and a "Vice President, Chief Financial Officer") supported by eight director/managers with responsibilities for:

- Production;
- Economics and Engineering Sciences;
- Reliability and Field Services;
- Environmental, Health and Safety and Risk Management;
- Strategic Planning;

- Marketing;
- Human Resources; and
- Corporate Services.

Gunther Baumgartner, President, Refinery Manager, is a chemical engineer with over 25 years in the oil industry including eight years with North Atlantic: four years as President and prior to that as Director of Economics and Engineering Sciences. Prior to joining North Atlantic in 1998, Mr. Baumgartner was a refinery supply manager and a trader with Vitol.

Glenn Mifflin, Vice President, Chief Financial Officer, is a Chartered Accountant with a Masters of Business Administration with over 19 years of experience in the oil industry. Mr. Mifflin has held a number of positions within North Atlantic including serving as President of North Atlantic's Marketing Division.

Employees and Labour Relations

North Atlantic has approximately 570 full-time employees of which 65% are unionized and approximately 140 part-time employees of which 90% are unionized. The unionized employees are represented by the United Steel Workers of America. North Atlantic has had a history of good relations collective bargaining with its union which is evidenced by the lack of any strike action at the Refinery. The collective agreements with the United Steel Workers of America expire in late 2007 and early 2008. See "*Risk Factors*".

North Atlantic maintains a number of employee benefit programs for its employees including basic life insurance and accidental death and dismemberment insurance, extended healthcare and dental coverage. North Atlantic also maintains defined benefit and defined contribution pension plans for its employees and provides certain post retirement health care benefits which cover substantially all employees and their surviving spouses. At December 31, 2006, the pension plan and other benefit plan obligations exceeded the pension plan and other benefit plan funding by approximately $12.2 million. For additional information, refer to Note 17 in Harvest's audited consolidated financial statements for the year ended December 31, 2006 filed on SEDAR at www.sedar.com.

Environment, Health and Safety Policies and Practices

Consistent with our petroleum and natural gas business, North Atlantic has an active and comprehensive Integrated Management System to promote the integration of safety, health and environmental awareness into our refinery and related businesses. In 2006 the refinery was audited by the Workplace Health, Safety and Compensation Commission and received a rating of 97.2 which is the most positive rating given by WHSCC on an initial audit. Hydrocarbon contamination through spills achieved a record low in 2006 with only 0.25 litres lost to water and 1.2 m3 to land. Our refinery inspection program continued to gain more prominence as we completed 434 inspections in 2006 versus 294 in 2005. SO2 emissions at the refinery were 8.6% below the approved limit for the year, and there were no SO2 emissions above the air quality standards in surrounding communities, nor were there any violation of daily SO2 limits.

Industry Conditions

The petroleum refining industry is subject to extensive controls and regulations governing its operations (including marine transportation product specifications, refining emissions and market pricing) imposed by legislation enacted by various levels of government all of which should be carefully considered by investors in the petroleum refining industry. It is not expected that any of these controls or regulations will affect Harvest's operations in a manner materially different than they would affect other petroleum refining entities of similar size. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the petroleum refining industry.

Industry Background

An oil refinery is a manufacturing facility that uses crude oil and other feedstocks as a raw material and produces a variety of refined products. The actual mix of refined products from a particular refinery varies according to the refinery's processing units, the specific refining process utilized and the nature of the crude oil feedstock. The refinery processing units generally perform one of three functions: the different types of hydrocarbons in crude oil are separated, the separated hydrocarbons are converted into more desirable or higher value products, or chemicals treat the products to remove unwanted elements and components such as sulphur, nitrogen and metals. Refined products are typically differing grades of gasoline, diesel fuel, jet fuel, furnace oil and heavier fuel oil.

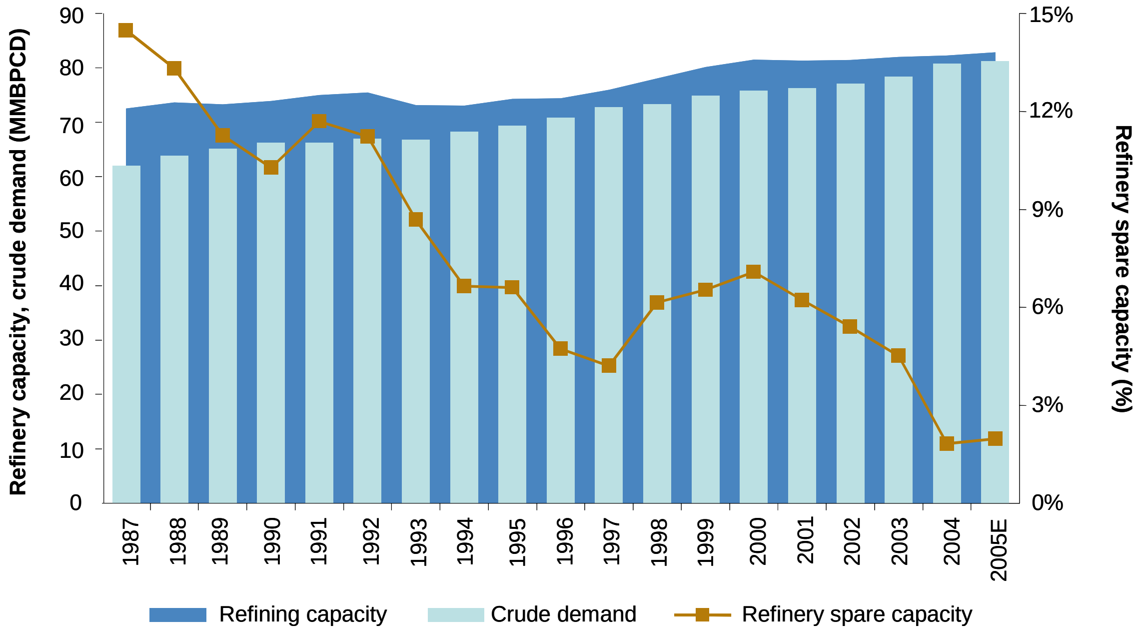
Refining is primarily a margin based business where the crude oil feedstocks and the refined products are commodities. Both crude oil and refined products in each regional market react to a different set of supply/demand and transportation pressures and refiners must balance a number of competing factors in deciding what type of crude oil to process, what kind of equipment to invest in and what range of products to manufacture. As most refinery operating costs are relatively fixed, the refining goal is to maximize the yield of high value refined products and to minimize crude oil feedstock costs. The value and yield of refined products are a function of the refinery equipment and the characteristics of the crude oil feedstock while the cost of feedstock depends on the type of crude oil. The refining industry depends on its ability to earn an acceptable rate of return in its marketplace where prices are set by international as well as local markets.

Demand for refined oil products has significantly increased in recent years due to the industrialization of countries such as China and India. As economic conditions improve in these countries, demand for gasoline and diesel continues to rise due to rising transportation usage and power generation requirements. In the United States, the demand for gasoline continues to rise while Europe is experiencing rapid growth in demand for diesel. Over the long term, refining margins and crude oil prices are typically correlated as both are driven by the demand for refined petroleum products.

Until recently, global investment in refining capacity has been restrained as weak refining margins have not supported investment in either capacity increases at existing refineries or the construction of new refineries. From the early 1980's through the early 1990's, global refining capacity fell as uneconomic refineries were shut down in the face of low margins. Since then, global refining capacity has grown, predominantly through capacity creep, but at a pace insufficient to keep up with the growth in global demand for refined products. Given the lead-time required to engineer and construct new refining facilities and resistance to refineries being built in many areas, it is expected that the global refined product market should be strong for several years.

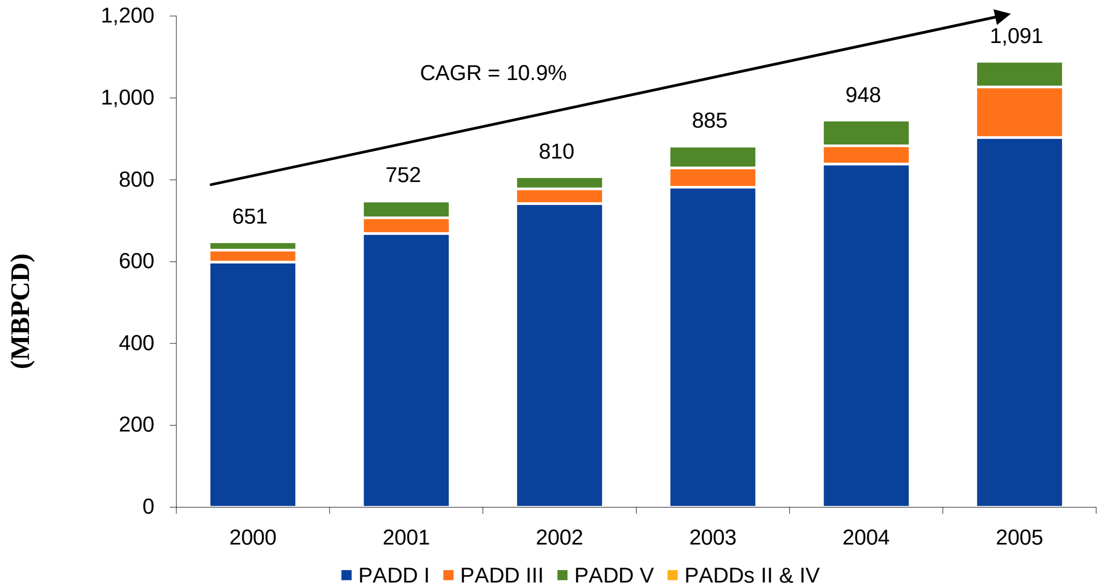
In addition to the global tightening of the refined product supply/demand balance, global crude oil supply has become heavier and higher in sulphur content. The incremental production from most OPEC countries and many other producers has tended to be sour crude, containing more sulphur, while incremental crude oil production from Canada, Venezuela and Mexico has been both heavy and sour. Because global refining capacity is largely configured to process the higher gravity and lower sulphur crude oil, lower gravity and more sour crude oil have increasingly been sold at a discount to the lighter and sweeter crude oil. At the same time, refiners have turned to lighter and sweeter crude oil as feedstocks to meet the lower sulphur fuel specifications in North America and Europe resulting in a greater discount for sour crude oil. Notwithstanding the widening quality differentials, the higher prices paid for all crude oil has accelerated the development of heavier gravity and higher sulphur crude oil production. As a result, quality differentials are expected to remain wide providing a significant economic benefit for those refiners able to process lower quality crude oil into higher value refined products.

As presented in the following graph, moderate creep in refinery capacity has not kept pace with the demand for crude oil resulting in the spare refining capacity tightening from over 15% in 1987 to less than 3% in 2005.



Source: Capacity per Energy Information Administration and Demand per BP Statistical Review.

Consistent with global trends, near-term growth in US demand for refined products is expected to continue to exceed growth in domestic refining capacity and projected growth in the supply of lower quality heavy-sour crude oil is expected to exceed the capacity to process such crude oil. Both trends are expected to continue to support the historically high US refining margins as any significant expansion in domestic supply capacity beyond capacity creep will require at least three to five years of lead time. The expected imbalance in US supply of, and demand for, refined products will likely be met by the importing of refined products. However, anticipating that refining capacity in most major supply sources appear fully committed, US refining margins will need to remain strong to attract imports from more distant locations. Since 1995, growth in imports has been most apparent in gasoline supply, where imports have grown by over 10% annually in the United States east coast market (known as PADD 1), where regional product demand significantly exceeds refining capacity, and being the primary import point for petroleum product into the U.S.



Source: AEGIS Energy Advisors Corp.

Refining is primarily a margin-based business where refiners generate profits by selling refined products at prices higher than the costs of acquiring crude oil feedstock and converting into refined products. A refinery's location can also have an important impact on its refining margins as location can influence access to crude oil feedstocks and the efficient distribution of refined products. As a benchmark indicator of refining margins, the New York Mercantile Exchange ("**NYMEX**") "2-1-1 crack spread" is a marketable derivative product that mirrors the gross margin attainable by a refiner processing two barrels of light sweet crude oil (as defined by the West Texas Intermediate benchmark price ("**WTI**")) and selling two barrels of refined product, consisting of one barrel of gasoline and one barrel of diesel into the New England market where product prices are set in relation to NYMEX gasoline and NYMEX diesel prices. Sour crude oil traditionally sells at a discount to light sweet crude oil, and hence, the margin for refiners that refine sour crude oil is characterized as a "sour crack spread" which includes a differential between the WTI price and the price for Deepwater Sour Mars Blend Oil crude oil price, a representative sour crude oil, as well as the "2-1-1 crack spread."

Pricing and Marketing

Since 2001, in the provinces of Newfoundland and Labrador, the sales price of residential home heating fuels and automotive gasoline and diesel fuel sold within the Province of Newfoundland and Labrador is subject to regulation under the *Petroleum Product Act* (Newfoundland), administered by the Public Utilities Board. Under this act, the Pricing Commissioner has the authority to set the maximum wholesale and retail prices that a wholesaler and a retailer may charge and to determine the minimum and maximum mark-up between the wholesale price to the retailer and the retail price to the consumer within the Province of Newfoundland and Labrador. The wholesale and retail prices of petroleum products is adjusted monthly based on the New York Harbour benchmark price for these products, however, the prices may be adjusted more frequently when circumstances warrant.

RISK FACTORS

Both Harvest's petroleum and natural gas operations and its petroleum refining operations are conducted in the same business environment most other operators in the respective businesses and the business risks are very similar. However, the Harvest Energy Trust structure is significantly different than that of a traditional corporation with share capital and there are certain unique business risks of Harvest's structure. Accordingly, Harvest's business risks have been segregated into those generally applicable to petroleum and natural gas operators as well as petroleum refining operators and those applicable to royalty trusts as well as those risks particular to Unitholders resident in the United States and other non-residents of Canada.

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

Risks Related to Harvest's Petroleum and Natural Gas Operations

Volatility of Commodity Prices and Foreign Exchange Risk

The Trust's cash flow from operations and financial condition are dependent on its Net Profits Interests and the Direct Royalties which are dependent on the prices received for the sale of petroleum, natural gas and natural gas liquids production. Prices for petroleum, natural gas and natural gas liquids have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil producing regions, which are beyond the control of Harvest Operations or the Trust. Oil prices received from production in Canada also reflect changes in the Canadian/U.S. currency exchange rate. A decline in petroleum and/or natural gas prices or an increase in the Canadian/US currency exchange rate could have a material adverse effect on the Trust's cash flow from operations, financial condition and the cash available for distribution to Unitholders as well as funds available for the development of its Operating Subsidiaries petroleum and natural gas reserves. From time to time, Harvest Operations may manage the risk of changes in commodity prices and currency exchange rates by entering into commodity price risk management contracts and/or currency exchange contracts. To the extent that Harvest Operations or the Trust engage in risk management activities related to commodity prices and currency exchange rates, it will be subject to counterparty risk. In addition, commodity price risk management contracts may require, from time to time, margin payments to be made which could reduce the Trust's cash available for distribution to Unitholders.

Crude Oil Differentials

At the end of 2006, Harvest's production was approximately 45% light and medium gravity crude oil, 25% heavy oil and 30% natural gas. Processing and refining heavy oil is more expensive than processing and refining light oil and accordingly, producers of heavy oil receive lower prices for their production. The differential between light oil and heavy oil has fluctuated widely during recent years and when compounded with the fluctuations in the benchmark prices for light oil, the result is a substantial increase in the volatility of heavy oil prices. An increase in the heavy oil differential usually results in Harvest receiving lower prices for its heavy oil and could have a material adverse effect on the Trust's cash flow from operations, financial condition and the cash available for distribution to Unitholders as well as funds available for the development of its oil and natural gas reserves. The heavy oil price differential is normally the result of the seasonal supply and demand for heavy oil, pipeline constraints and heavy oil processing capacity of refineries, all of which are beyond the control of Harvest Operations.

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 Harvest Operation's assets and potentially, liability to third parties. Harvest Operations employs prudent risk management practices and maintains liability insurance in amounts consistent with industry standards. In addition, business interruption insurance has been purchased for selected facilities. The Trust's Operating Subsidiaries may become liable for damages arising from such events against which it cannot insure against or 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 Trust's cash flow from its NPI.

Continuing production from a property and to some extent, the marketing of production therefrom, are largely dependent upon the capabilities of the operator of the property. To the extent the operator fails to perform its duties properly, production may be reduced and proceeds from the sale of production from properties operated by third parties may be negatively impacted. Although Harvest Operations operates the majority of its Properties, there is no guarantee that it will remain operator of such Properties or that it will operate other Properties that may be acquired.

A significant portion of Harvest's operating expenses are electrical power costs. Since deregulation of the electrical power system in Alberta in recent years, electrical power prices have been set by the market based on supply and demand and recently, electrical power price in Alberta have been volatile. Generally, this volatility has resulted in higher electrical power prices which negatively impact Harvest's operating expenses, and in turn, the Trust's cash flow from operations and cash available for distribution to Unitholders. To mitigate its exposure to the volatility in electrical power prices, Harvest Operations has entered into fixed priced forward purchase contracts for approximately 50% of its electrical power consumption in Alberta through December 2008. In respect of its operations in Saskatchewan, the Saskatchewan power system is regulated and as such, electrical power costs are not subject to significant volatility. However, there can be no certainty that the Saskatchewan power system will not deregulate in the future.

Although satisfactory title reviews will generally be conducted on the Properties in accordance with industry standards, such reviews do not guarantee or certify that a defect in title may not arise to defeat the claim of an Operating Subsidiary to certain Properties. A reduction of cash flow from a net profits interest or income from Direct Royalties payable to the Trust could result from such circumstances.

Harvest's ability to market petroleum and natural gas from its wells also depends upon numerous other factors beyond its control, including:

- The availability of capacity to refine heavy oil;
- The availability of natural gas processing capacity;
- The availability of pipeline capacity;
- The availability of diluent to blend with heavy oil to enable pipeline transportation;
- The price of oilfield services;
- The accessibility of remote areas to drill and subsequently service wells and facilities; and,
- The effects of inclement weather;

Because of these factors, Harvest may be unable to market all of the petroleum or natural gas it is capable of producing or to obtain favourable prices for the petroleum and natural gas it produces.

Reserve Estimates

The reserve and recovery information contained in Harvest's Reserve Reports are only an estimate, such estimates are complex to determine, and the actual production and ultimate reserves recovered from the Properties may differ from the estimates prepared by the Independent Reserve Engineering Evaluators.

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

Depletion of Reserves (Sustainability)

The Trust's cash flow from operations and cash available for distribution to unitholders, 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. Harvest will not be reinvesting to the same extent as other industry participants as it makes cash distributions to its unitholders. Accordingly, absent additional capital investment from other sources, production levels and reserves attributable to the Properties will decline.

The Operating Subsidiaries' future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on their success in exploiting its resource base and acquiring additional reserves. Without reserve additions through acquisition or development activities, the Operating Subsidiaries' reserves and production will decline over time as reserves are produced. There can be no assurance that the Operating Subsidiaries will be successful in developing or acquiring additional reserves on terms that meet the Operating Subsidiaries' investment objectives.

Failure to Realize an Adequate Rate of Return on Prices Paid for Properties

The prices paid for acquisitions were based, in part, 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 Harvest. In particular, changes in the prices of and markets for petroleum and natural gas from those anticipated at the time of making acquisitions will affect the value of the Trust Units. In addition, all engineering assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than those currently attributed to the Properties.

Changes in Legislation

There can be no assurance that income and capital tax laws, government incentive programs and regulations relating to the petroleum and natural gas industry, such as environmental and operating regulations, will not be changed in a manner which adversely affects Harvest.

Environmental Concerns

The petroleum 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 on the Operating Subsidiaries or the issuance of clean up orders on the Properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on Harvest. See "General Business Description – Petroleum and Natural Gas Business".

Additionally, the potential impact of Canada's ratification of the Kyoto Protocol on Harvest's business and the Trust's cash flow from operations and cash available for distribution to Unitholders with respect to instituting reductions of greenhouse gases is difficult to quantify at this time.

Competition

There is strong competition relating to all aspects of the petroleum and natural gas industry. The Operating Subsidiaries and/or the Trust actively compete for capital, skilled personnel, undeveloped land, 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 petroleum and natural gas organizations, many of which may have greater technical and financial resources than the Operating Subsidiaries and/or the Trust, individually or combined. 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 Harvest Operations are directors or officers of corporations which are in competition to the interests of Harvest. No assurances can be given that opportunities identified by such board members will be provided to the Operating Subsidiaries and/or the Trust. See "Conflicts of Interest".

Risks Related to Harvest's Petroleum Refining and Related Marketing Operations

Investment in North Atlantic

Harvest's investment in North Atlantic is in the form of interest bearing notes and interests in various partnerships and trusts, and accordingly, Harvest is dependent upon the ability of North Atlantic to pay its interest obligations under the notes and distributions from the various partnerships. North Atlantic's ability to pay interest and distributions is entirely dependent on its operations and assets which will be impacted by risks typical of refinery and marketing operations.

Volatility of Commodity Prices

North Atlantic's earnings and cash flows from refining and wholesale and retail marketing operations are dependent on a number of factors including fixed and variable expenses (including the cost of crude oil and other feedstocks) and the price at which North Atlantic is able to sell refined products. In recent years, the market prices for crude oil and refined products have fluctuated substantially. These prices depend on a number of factors beyond North Atlantic's control, including the demand for crude oil and other refined products, which are subject to, among other things:

- Changes in the global demand for crude oil and refined products;
- The level of foreign and domestic production of crude oil and refined products;
- Threatened or actual terrorist incidents, acts of war, and other worldwide political conditions in both crude oil producing and refined product consuming regions;
- The availability of crude oil and refined products and the infrastructure to transport crude oil and refined products;
- Supply and operational disruptions including accidents, weather conditions, hurricanes or other natural disasters;
- Government regulations including changes in fuel specifications required by environmental and other laws;
- Local factors including market conditions and the operations of other refineries in the markets in which North Atlantic competes; and
- The development and marketing of competitive alternative fuels.

Generally, fluctuations in the price of gasoline and other refined products are correlated with fluctuations in the price of crude oil, however, the prices for crude oil and prices for refined products can fluctuate in different directions as a result of worldwide market conditions. Further, the timing of the relative movement in prices as well as the magnitude of the change could significantly influence refining margins as could price changes occurring during the period between purchasing crude oil feedstock and selling refined products manufactured from the feedstock. North Atlantic does not produce crude oil and must purchase all of its crude oil feedstock at prices that fluctuate with worldwide market conditions and this could significantly impact North Atlantic's earnings and cash flow. Although Harvest produces crude oil in western Canada, this crude oil cannot be economically transported to the Refinery. North Atlantic also purchases refined products from third parties for sale to its customers and price changes during the period between purchasing and selling these products may also impact North Atlantic's earnings and cash flow.

North Atlantic purchases approximately 250,000 megawatt hours of electrical power from Newfoundland and Labrador Hydro, a provincial crown corporation. A substantial proportion of Newfoundland and Labrador Hydro's electricity is generated by hydroelectric power, a relatively inexpensive source compared to fossil fuel generators. However, North Atlantic's cost of electrical power has increased from $0.024 per kilowatt hour in 2002 to $0.041 in

2005, a near doubling in price. Electricity prices have been and will continue to be affected by supply and demand for service in both local and regional markets and continued price increases will impact North Atlantic's earnings and cash flow.

Fluctuations in the Canada-United States Exchange Rates

The prices for crude oil and refined products are generally based on market prices in U.S. dollars while North Atlantic's operating costs and capital expenditures are primarily in Canadian dollars. Fluctuations in the exchange rates between the U.S. and Canadian dollar will give rise to currency exchange rate exposure for North Atlantic. Although this currency exchange rate exposure may be hedged, there can be no assurance that a currency exchange rate risk management program will be sufficient to effectively cover all of North Atlantic's exposure.

Disruptions in the Supply of Crude Oil and Delivery of Refined Products

North Atlantic's Refinery receives all of its crude oil feedstock and delivers approximately 90% of its refined products via water born vessels including very large crude carriers capable of handling over 2 million barrels of crude oil. In addition to environmental risks of handling such vessels discussed below, North Atlantic could experience a disruption in the supply of crude oil because of accidents, governmental regulation or third party actions. A prolonged disruption in the availability of vessels to deliver crude oil to the Refinery and/or to deliver refined products to market would have a material adverse effect on North Atlantic's business, financial condition and results of operations.

Over the past three years, North Atlantic purchased over 60% of its crude oil feedstock from sources in the Middle East. North Atlantic does not maintain long term contracts with any of its crude oil suppliers. To the extent that its crude oil suppliers, particularly suppliers in the Middle East, reduce the volume of crude oil supplied to North Atlantic as a result of declining production or competition or otherwise, North Atlantic's business, financial condition and results of operations would be adversely affected to the extent that North Atlantic was not able to find another supplier with a substantial amount and similar type of crude oil. Further, North Atlantic has no control over the level of development in the fields that currently supply the Refinery nor the amount of reserves underlying such fields, the rate at which production will decline or the production decisions of the producers which are affected by, among other things, prevailing and projected crude oil prices, demand for crude oil, geological considerations, government regulation and the availability and cost of capital.

North Atlantic is relying on the creditworthiness of Vitol Refining S.A. for its purchase of crude oil feedstock for the Refinery pursuant to the Supply and Offtake Agreement and will be relying on the creditworthiness of Harvest to enter into price risk management contracts to reduce North Atlantic's exposure to adverse fluctuations in the prices of crude oil and refined products. Accordingly, should the creditworthiness of Vitol Refining S.A. and/or Harvest deteriorate, crude oil suppliers and financial counterparties may change their view on supplying North Atlantic with crude oil and price risk management contracts, respectively, and induce them to shorten the payment terms or require additional credit support, such as letters of credit. Due to the large dollar amount of credit associated with the volume of crude oil purchases and long-term price risk management contracts, any imposition of more burdensome payment terms on North Atlantic may have a material adverse effect on North Atlantic's and Harvest's financial liquidity which could hinder North Atlantic's ability to purchase sufficient quantities of crude oil to operate the Refinery at full capacity. In addition, if the price of crude oil increases significantly, the credit requirements to purchase enough crude oil to operate the Refinery at full capacity will also increase. A failure to operate the Refinery at full capacity could have an adverse material affect on North Atlantic's business, financial condition and results of operations as well as Harvest's financial condition and the Trust's cash flow from operations.

Operational Risks

The Refinery is a single integrated and interdependent facility which could experience a major accident, be damaged by severe weather or other natural disaster, or otherwise be forced to shut down. A shutdown of one part of the Refinery could significantly impact the production of refined products and may reduce, and even eliminate, North Atlantic's cash flow. Any one or more of the Refinery's processing units may require a planned turnaround or encounter unexpected downtime for maintenance or repair and the time required to complete the work may take longer than anticipated. There are no assurances that the Refinery will produce refined products in the quantities or at the cost anticipated, or that it will not cease production entirely in certain circumstances which could have a material adverse effect on North Atlantic's business, financial condition and results of operations as well as Harvest's financial condition and the Trust's cash flow from operations.

North Atlantic's refining operations, including the transportation of and storage of crude oil and refined products, are subject to hazards and inherent risks typical of similar operations such as fires, natural disasters, explosions, spills and mechanical failure of its equipment or third-party facilities, any of which can result in personal injury claims as well as damage to North Atlantic's properties and the properties of others. While North Atlantic carries property, casualty and business interruption insurance, North Atlantic does not maintain insurance coverage against all potential losses, and could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on North Atlantic's business, financial condition and results of operations as well as Harvest's financial condition and the Trust's cash flow from operations.

Currently, North Atlantic has the opportunity and intends to consider opportunities to grow its business through the reconfiguration and enhancement of its Refinery assets with the suite of expansion or de-bottlenecking projects plus a coker project or a visbreaker project for bottoms upgrading. However, if unanticipated costs occur or North Atlantic's revenues decrease as a result of lower refining margins, operating difficulties or other matters, there may not be sufficient capital to enable North Atlantic to fund all required capital and operating expenses. There can be no assurance that cash generated by North Atlantic's operations or funding available from debt financings or further investment by Harvest will be available to meet capital and operating requirements.

The operation of refineries and related storage tanks is inherently subject to spills, discharges or other releases of petroleum or hazardous substances. If any of these events had previously occurred or occurs in the future in connection with any of North Atlantic's Refinery or storage tanks, or in connection with any facilities to which North Atlantic sends wastes or by-products for treatment or disposal, other than events for which North Atlantic is indemnified, North Atlantic could be liable for all costs and penalties associated with their remediation under federal, provincial and local environmental laws or common law, and could be liable for property damage to third parties caused by contamination from releases and spills. The penalties and clean-up costs that North Atlantic may have to pay for releases or spills, or the amounts that North Atlantic may have to pay to third parties for damage to their property, could be significant and the payment of these amounts could have a material adverse effect on North Atlantic's business, financial condition and results of operations as well as Harvest's financial condition and the Trust's cash flow from operations.

North Atlantic operates in environmentally sensitive coastal waters where tanker operations are closely regulated by federal, provincial and local agencies and monitored by environmental interest groups. Transportation of crude oil and refined products over water involves inherent risk and subjects North Atlantic to the provisions of Canadian federal laws and the laws of the Province of Newfoundland and Labrador. Among other things, these laws require North Atlantic to demonstrate its capacity to respond to a "worst case discharge" to a maximum 10,000 metric tonne oil spill. North Atlantic's marine division manages vessel traffic to the Refinery and works with regulatory authorities on measures to prevent and mitigate the risk of oil spills and other marine related matters. The marine division has two tugboats to assist in berthing and unberthing tankers at North Atlantic's dock with one tugboat equipped with fire fighting capability and the other equipped for spill response capability. The tugboat operations have a safety management system certified under the International Safety Management Code and are also certified under the International Ship and Port Security Code. In addition, North Atlantic has contracted with the Eastern Canada Response Corporation to supplement its resources. However, there may be accidents involving tankers transporting crude oil or refined products, and response services may not respond in a manner to adequately contain a discharge and North Atlantic as well as Harvest may be subject to a significant liability in connection with a discharge.

North Atlantic has in the past operated service stations with underground storage tanks in the Province of Newfoundland and Labrador, and currently operates 13 retail service stations and 2 cardlock locations, with underground storage tanks. North Atlantic is required to comply with provincial regulations governing such storage tanks in the Province of Newfoundland and Labrador and compliance with these requirements can be costly. The operation of underground storage tanks also poses certain other risks, including damages associated with soil and groundwater contamination. Leaks from underground storage tanks which may occur at one or more of North

Atlantic's service stations, or which may have occurred at previously operated service stations, may impact soil or groundwater and could result in fines or civil liability for North Atlantic. While North Atlantic maintains insurance in respect of such risks, there are no assurances that such insurance will be adequate to fully compensate for any liability North Atlantic may incur if such risks were to occur.

Environmental, Health and Safety Risks

North Atlantic's operations and properties are subject to extensive federal, provincial and local environmental and health and safety regulations governing, among other things, the generation, storage, handling, use and transportation of petroleum and hazardous substances, the emission and discharge of materials into the environment, waste management and characteristics and composition of gasoline and diesel fuels. If North Atlantic fails to comply with these regulations, it may be subject to administrative, civil and criminal proceedings by governmental authorities as well as civil proceedings by environmental groups and other entities and individuals. A failure to comply, and any related proceedings, including lawsuits, could result in significant costs and liabilities, penalties, judgments against North Atlantic or governmental or court orders that could alter, limit or stop North Atlantic's operations.

Consistent with the experience of other Canadian refineries, environmental laws and regulations have raised operating costs and required significant capital investments at the Refinery. Harvest believes that the Refinery is substantially compliant with existing laws and regulatory requirements. However, potentially material expenditures could be required in the future may be required for North Atlantic to comply with evolving environmental, health and safety laws, regulations or requirements that may be adopted or imposed in the future.

In addition, new environmental laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement or other developments could require North Atlantic to make additional unanticipated expenditures. Many of these laws and regulations are becoming increasingly stringent, and the cost of compliance with these requirements can be expected to increase over time. Harvest is not able to predict the impact of new or changed laws or regulations or changes in the ways that such laws or regulations are administered, interpreted or enforced. The requirements to be met, as well as the technology and length of time available to meet those requirements, continue to develop and change. To the extent that the costs associated with meeting any of these requirements are substantial and not adequately provided for, there could be a material adverse effect on North Atlantic's business, financial condition and results of operations as well as Harvest's financial condition and the Trust's cash flow from operations.

North Atlantic is presently subject to litigation and investigations with respect to the use of MTBE and the delivery of contaminated sulphur (see "Legal Proceedings"). North Atlantic may become involved in further litigation or other proceedings, or may be held responsible in any existing or future litigation or proceedings, the costs of which could be material.

Management Risks

North Atlantic's future performance depends to a significant degree upon the continued contributions of its senior management team and key technical and operations employees. The loss of one or more members of the senior management team or a number of key technical and operations employees could result in a disruption to North Atlantic's operations. In addition, North Atlantic faces competition for these key individuals from competitors, customers and other companies operating in the refining industry and to the extent that North Atlantic loses members of its senior management team or key technical and operations employees for any reason, North Atlantic will be required to hire other personnel to manage and operate North Atlantic and it may not be able to locate or employ such qualified personnel on acceptable terms. As a result, the operating history of North Atlantic which has resulted in revenue and profitability growth rates may not be indicative of North Atlantic's future operations, prospects and viability.

Employee Relations

North Atlantic has approximately 570 full-time employees and 140 part-time employees of which approximately 65% and 90%, respectively, are represented by the United Steel Workers of America pursuant to collective bargaining agreements expiring in 2007 and 2008. North Atlantic may not be able to renegotiate these collective agreements on satisfactory terms, or at all, which may result in an increase in operating costs. In addition, the existing collective agreements may not prevent a strike or work stoppage in the future, and any such work stoppage could have a material adverse effect on North Atlantic's business, financial condition and results of operations as well as Harvest's financial condition and the Trust's cash flow from operations.

Competition

North Atlantic competes with a broad range of refining and marketing companies, including multinational oil companies. Because of their geographic diversity, larger and more complex refineries, integrated operations and greater resources, some of North Atlantic's competitors may be better able to withstand volatile market conditions, to compete on the basis of price, to obtain crude oil in times of shortage and to bear the economic risks inherent in all phases of the refining industry.

Terrorist Attacks, Threats of Attacks or Acts of War

North Atlantic's business is affected by general economic conditions as well as fluctuations in consumer confidence and spending which can decline as a result of numerous factors outside of its control, such as terrorist attacks, threatened terrorist attacks or acts of war. Terrorist attacks, as well as events occurring in response to or in connection with them, including future terrorist attacks against Canadian or U.S. targets, rumours or threats of war, actual conflicts involving the military of Canada, the United States or their allies could cause trade disruptions impacting North Atlantic's crude oil suppliers or refined products customers or energy markets generally, and may adversely impact North Atlantic's business, financial condition and results of operations as well as Harvest's financial condition and the Trust's cash flow from operations.

Since the terrorist attacks of September 11, 2001, the Government of the United States of America has issued public warnings that energy-related assets (which could include North Atlantic's Refinery) may be at greater risk of future terrorist attacks than other targets in Canada or the United States. Such occurrences could significantly impact energy prices, including prices for crude oil and refined products which could have a material adverse effect on North Atlantic's business, financial condition and results of operations as well as Harvest's financial condition and the Trust's cash flow from operations.

Risks Related to Harvest's Structure

Debt Service

As of March 20, 2007, Harvest has indebtedness of approximately $1.3 billion under its Three Year Extendible Revolving Credit Facility. In addition, letters of credit have been issued to third parties totalling approximately $1 million on behalf of Harvest Operations to secure services, primarily electric power, for its petroleum and natural gas operations. Harvest Operations has also issued U.S.$250 million of $7^{7/8}$% Senior Notes due October 15, 2011 on which semi-annual interest payments are required. The Operating Subsidiaries have provided the lenders under its Three Year Extendible Revolving Credit Facility with security over all of Harvest's assets. If Harvest commits an event of default or the lenders demand repayment, the lenders may foreclose on and/or sell Harvest's assets free from, or together with, the NPI encumbrance.

Certain payments by the Operating Subsidiaries and the Trust's cash distributions to Unitholders are prohibited upon an event of default or demand for repayment under the Three Year Extendible Revolving Credit Facility. Any indebtedness of the Operating Subsidiaries to the Trust pursuant to the NPI and amounts payable to the Unitholders under the Trust Indenture are subordinate to payment required pursuant to the Three Year Extendible Revolving Credit Facility pursuant to subordination agreements between the Lenders, the Trust, and the Operating Subsidiaries. These subordination agreements may restrict the ability of the Operating Subsidiaries to pay amounts owing under the NPI to the Trust or pay interest or principal on any indebtedness owing to the Trust or other amounts owing to the Trust, and therefore may limit or eliminate the Trust's cash available for distribution to Unitholders.

Harvest must meet certain ongoing financial and other covenants under the Three Year Extendible Revolving Credit Facility. The covenants are customary restrictions on the Operating Subsidiaries' operations and activities, including restrictions on the incurring of indebtedness, the granting of security, the issuance of incremental debt and the sale of assets. Harvest is also subject to certain covenants under the note indenture respecting the $7^{7/8}$% Senior Notes, including limitations on the ability of Harvest to issue secured debt and to pay cash distributions to unitholders.

Debt Repayment

Harvest is permitted to borrow funds to finance the purchase of assets, incur capital expenditures, repay other obligations and for working capital purposes. Borrowings of the Operating Subsidiaries may be repaid with funds received from the Trust. Debt service costs of the Operating Subsidiaries are deducted in computing income from the Net Profits Interest payments and debt service costs of the Trust reduce the Trust's cash available for distribution to Unitholders. Variations in interest rates could result in significant changes in the amount required to be applied to debt service before payment of the NPI obligations and result in less cash available for distribution to Unitholders.

Interest and principal payable pursuant to the $7^{7/8}$% Senior Notes are payable in U.S. dollars. Harvest is permitted to borrow funds under the credit facilities in U.S. dollars and would be required to settle interest and principal amounts in the same currency. Variations in the Canadian/U.S. currency exchange rate could result in a significant increase in the amount of the interest and principal payments under the Three Year Extendible Revolving Credit Facility and the $7^{7/8}$% Senior Notes, thereby reducing the Trust's cash available for distribution to Unitholders.

Variability of Cash Distributions

The Operating Subsidiaries may retain a portion of their cash flows from the Properties to facilitate the development of the Properties. Harvest believes this will assist in maintaining distributions over a longer period than would otherwise be the case if all cash flows from the Properties were paid to the Trust and subsequently distributed to the Unitholders. Future cash flows from such Properties may not be sufficient to fully recover the development costs and may not generate sufficient cash flows to allow the Operating Subsidiaries to maintain their Net Profits Interest payments to the Trust resulting in a reduction in the Trust's cash available for distribution to Unitholders over the longer term.

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 petroleum and natural gas sector and should not be viewed by investors as shares in Harvest Operations or any of the Operating Subsidiaries. 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 distribution to Unitholders, the value of the Properties acquired by Harvest and the Operating Subsidiaries' ability to affect the long-term cash flows from the 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 petroleum and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

Unitholder Limited Liability

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

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

The activities of the Trust and Operating Subsidiaries 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 Operating Subsidiaries and having contracts signed by or on behalf of the Trust include a provision that such obligations are not binding upon Unitholders personally.

The provinces of Alberta and Ontario have recently passed legislation providing unitholders of mutual fund trusts the same limited liability protections afforded shareholders of corporations.

Investment Eligibility

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

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 Operating Subsidiaries' ability to make the necessary capital investments to maintain or expand its petroleum and natural gas reserves will be impaired. To the extent the Trust or the Operating Subisdiaries are required to use cash flow to finance capital expenditures or property acquisitions, the cash available for distribution to Unitholders will be reduced.

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 Board of Directors of Harvest Operations may determine. In addition, the Trust may issue additional Trust Units from time to time pursuant to the Trust Unit Rights Incentive Plan, Unit Award Incentive Plan and DRIP Plan. The possible issuance of these Trust Units could result in dilution to holders of Trust Units.

Reliance on Management of Harvest Operations

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

Return of Capital

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

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.

Structure of the Trust

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

Proposed Changes to The Tax Act

On October 31, 2006, the Minister of Finance of the Government of Canada proposed to apply a tax at the mutual fund trust level on distributions of certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate income tax rates in Canada and to treat such distributions as dividends to the unitholders (the "**October 31 Proposals**"). On December 21, 2006 the Minister of Finance released draft legislation to implement the October 31, 2006 Proposals pursuant to which, commencing January 1, 2011 (provided Harvest only experiences "normal growth" and no "undue expansion" before then), certain distributions from Harvest which would have otherwise been taxed as ordinary income generally will be characterized as dividends in addition to being subject to tax at corporate rates at the mutual fund trust level. Assuming the October 31 Proposals are ultimately enacted in their present form, the implementation of such legislation would be expected to result in adverse tax consequences for Harvest and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada) and may impact cash available for distribution to Unitholders.

In the days following the announcement of the Proposal, a communications and government relations program was launched by an organization of which Harvest is a member, the Canadian Association of Income Funds ("**CAIF**"). CAIF was formed in 2002 to represent and promote the interests of all Canadian income funds, publicly listed limited partnerships, income trusts and royalty trusts, regardless of the sector or nature of the trust's business. A second organization, the Coalition of Canadian Energy Trusts ("**CCET**") was formed in the weeks following October 31, 2006, which has in its membership all of the Canadian oil and gas royalty trusts, including Harvest, and the majority of the related energy services and infrastructure trusts. Both independently and through its support and membership in the above two organizations, Harvest has been actively involved with efforts to educate and inform government representatives about the negative implications this Proposal presents for trusts generally and energy trusts specifically.

Management believes that the October 31 Proposals may reduce the value of the Trust Units, which would be expected to increase the Trust's cost of raising capital in the public markets. In addition management believes that the October 31 Proposals are expected to: (a) substantially eliminate the competitive advantage that Harvest and other Canadian energy trusts enjoy relative to their corporate peers in raising capital in a tax-efficient manner; and (b) place Harvest and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation. The October 31 Proposals are also expected to make trust units less attractive as an acquisition currency resulting in it becoming more difficult for Harvest to compete for acquisitions. There can be no assurance that Harvest will be able to reorganize its structure to substantially mitigate the expected impact of the October 31 Proposals.

Further, the proposals provide that any "undue expansion" (being defined as expansion beyond "normal growth") could result in the adverse tax consequences resulting from the proposals being realized sooner than January 1, 2011. On December 15, 2006, the Department of Finance issued guidelines with respect to what is meant by "normal growth" whereby "normal growth" would include equity growth within certain "safe harbour" limits measured by reference to the market capitalization of the respective publicly traded mutual fund trust as of the end of trading on October 31, 2006. The market capitalization would include only the market value of the issued and outstanding trust units and exclude any convertible debt, options or other interests convertible into or exchangeable for trust units. These safe harbour limits are 40% for the period from November 1, 2006 to December 31, 2007, and 20% each for calendar 2008, 2009 and 2010. Moreover, these limits are cumulative, so that any unused limit for a period carries over into the subsequent period. Additional details of the Department of Finance's guidelines include the following:

(a) new equity includes units and debt that is convertible into units (and may include other substitutes for equity if attempts are made to develop those);

(b) replacing debt that was outstanding as of October 31, 2006 with new equity, whether by a conversion into trust units of convertible debentures or otherwise will not be considered growth for these purposes and will therefore not affect the safe harbour; and

(c) the exchange, for trust units, of exchangeable partnership units or exchangeable shares that were outstanding on October 31, 2006 will not be considered growth for those purposes and will therefore not affect the safe harbour.

The Trust's market capitalization as of the close of trading on October 31, 2006, having regard only to its issued and outstanding Trust Units, was approximately $3.7 billion, which means the Trust's "safe harbour" equity growth amount for the period ending December 31, 2007 is approximately $1.5 billion, and for each of calendar 2008, 2009 and 2010 is an additional approximately $735 million (in any case, not including equity, including convertible debentures, issued to replace debt that was outstanding on October 31, 2006).

While these guidelines are such that it is unlikely they would affect Harvest's ability to raise the capital required to maintain and grow its existing operations in the ordinary course prior to January 1, 2011, they could adversely affect the cost of raising capital and Harvest's capability to undertake more significant acquisitions.

CAIF and CCET launched extensive public relations and government relations campaigns, held media and press conferences, and conducted individual and group meetings with government representatives, including the Minister of Finance. Through late January and early February 2007, the House of Commons Finance Committee held hearings to review the decision to tax income trusts, which featured testimony from financial experts, interest groups and other expert witnesses. The Committee subsequently issued a report that included a series of recommendations for amending the Proposal, including a reduction in the proposed tax rate and an extension of the transition period from four years to ten years.

It is not known at this time when the October 31 Proposals will be enacted by Parliament, if at all, or whether the October 31 Proposals will be enacted in the form currently proposed.

Risks Particular to Unitholders Resident in the United States and Other Non-Resident Unitholders

Unitholders Resident in the United States May be Subject to Passive Foreign Investment Company Rules

The Trust may be a passive foreign investment company for United States federal income tax purposes for the 2006 taxable year and in subsequent taxable years. To date, Harvest has not received advice that the Trust should not be considered a passive foreign investment company for the 2006 taxable year or previous taxable years. If the Trust were classified as a passive foreign investment company, Unitholders resident in the United States (other than most tax-exempt investors) would be subject to adverse tax rules. Under these adverse tax rules, Unitholders resident in the United States generally would be required to allocate any gain or excess distributions, which include any annual distributions other than in the first year the unitholder held the Trust Units, that is greater than 125% of the average annual distributions received by that unitholder in the three preceding taxable years or, if shorter, that unitholder's holding period for Trust Units. The amount allocated to the current taxable year and any year prior to the first year in which Harvest was a passive foreign investment company would be taxed as ordinary income in the current year. The amount allocated to each of the other taxable years would be subject to tax at the highest rate of tax in effect for the applicable class of taxpayer for that year, and an interest charge for the deemed deferral benefit would be imposed with respect to the resulting tax attributable to each of the other taxable years. Holders will not be able to make a "qualifying electing fund" election or, with respect to the Trust's Operating Subsidiaries that were considered to be passive foreign investment companies, a "mark-to-market" election to protect themselves from these adverse consequences if Harvest were ultimately determined to be a passive foreign investment company. Unitholders resident in the United States are strongly urged to consult their own tax advisors regarding the United States federal income tax consequences of Harvest's possible classification as a passive foreign investment company and the consequences of such classification.

Unitholders Resident in the United States and Other Non-Resident Unitholders may be subject to Additional Taxations

The Tax Act and the tax treaties between Canada and other countries may impose additional withholding and other taxes on the cash distributions or other property paid by the Trust to unitholders who are not residents of Canada and these taxes may change from time to time. For instance, since January 1, 2005, a 15% withholding tax is applied to all cash distributions made to all unitholders who are not residents of Canada.

The Ability of Unitholders Resident in the United States and Other Non-Resident Unitholders to Enforce Civil Remedies May be Limited

The Trust is a trust organized under the laws of Alberta, Canada and Harvest's principal place of business is in Canada. The directors and officers of Harvest Operations are residents of Canada and most of the experts who provide services to Harvest are resident of Canada and all or a substantial portion of their assets and Harvest's assets are located within Canada. As a result, it may be difficult for investors in the United States or other non-Canadian jurisdictions (a "**Foreign Jurisdiction**") to effect service of process within such Foreign Jurisdiction upon such directors, officers and representatives of experts who are not residents of the Foreign Jurisdiction or to enforce against them judgements of courts of the applicable Foreign Jurisdiction based upon civil liability under the securities laws of such Foreign Jurisdiction, including United States federal securities laws or the securities laws of any state within the United States. In particular, there is doubt as to the enforceability in Canada against Harvest or any of its directors, officers or representative of experts who are not residents of the United States, in original actions or in actions for enforcement of judgement of United States courts of liabilities based solely upon the United States federal securities laws or the securities laws of any state within the United States.

DISTRIBUTIONS TO UNITHOLDERS

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, dividends on the shares or other securities of the Operating Subsidiaries less all expenses and liabilities of the Trust, including debt service costs, which are due or accrued and which are chargeable to income.

The actual amount of cash available for distribution depends on, among other things, the quantity and quality of crude oil, natural gas and natural gas liquids produced, prices received for such production, direct expenses of the Trust, taxes, operating costs, transportation and processing costs, capital expenditures, debt service costs, Crown and other royalties, other Crown charges, net contributions to the reclamation funds, net contributions by the Operating Subsidiaries to the Reserve Account, and general and administrative costs of the Trust and the Operating Subsidiaries. See "Risk Factors". The Operating Subsidiaries also have the discretion to incur debt or retain cash in order to modify seasonal and other variations in cash available for distribution. Unitholders may also receive distributions of the net proceeds received from sales of Properties to the extent Harvest Operations determines not to use those proceeds to acquire additional Properties.

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

Pursuant to the provisions of the Trust Indenture all income earned by the Trust in a fiscal year, not previously distributed in that fiscal year, must be distributed to Unitholders of record on December 31. This excess income, if any, will be allocated to Unitholders of record at December 31 but the right to receive this income, if the amount if not determined and declared payable at December 31, will trade with the Trust Units until determined and declared payable in accordance with the rules of the Toronto Stock Exchange. To the extent that a Unitholder trades Trust Units in this period they will be allocated such income but will dispose of their right to receive such distribution. The following table sets forth the per Trust Unit amount of monthly cash distributions paid by the Trust for the periods indicated.

	2007	**2006**	**2005**	**2004**
January	$0.38	$0.35	$0.20	$0.20
February	$0.38	$0.35	$0.20	$0.20
March	$0.38	$0.38	$0.20	$0.20
April	$0.38(2)	$0.38	$0.20(1)	$0.20
May		$0.38	$0.20	$0.20
June		$0.38	$0.20	$0.20
July		$0.38	$0.20	$0.20
August		$0.38	$0.20	$0.20
September		$0.38	$0.20	$0.20
October		$0.38	$0.20	$0.20
November		$0.38	$0.20	$0.20
December		$0.38	$0.20	$0.20

Notes:

(1) In addition to the regular cash payment to Unitholders on April 15, 2005, the Trust also paid an extra distribution valued at $0.252 in the form of trust units to holders of record on March 31, 2005.

(2) The Trust announced on January 10, 2007 that monthly cash distribution of $0.38 per Trust Unit will be paid on April 16, 2007 to Unitholders of record on March 20, 2007.

GENERAL DESCRIPTION OF CAPITAL STRUCTURE

Harvest Energy Trust was created, and Trust Units issued, pursuant to the Trust Indenture. The Trust Indenture provides for the administration of Harvest, the investment of Harvest's assets, the calculation and payment of cash distributions to Unitholders, the calling of and conduct of business at meetings of Unitholders, the appointment and removal of the Trustee and the redemption of Trust Units. Among other things, material amendments to the Trust Indenture, the early termination of Harvest and the sale or transfer of all or substantially all of the property of Harvest require the approval of a Special Resolution by 66 2/3% of the votes cast at a Special Meeting of the Unitholders. The Trust Indenture has been amended and restated on each of July 10, 2003, May 4, 2005 and February 3, 2006.

The Trust has also issued five series of unsecured subordinated convertible debentures and in addition has also assumed two additional series of unsecured subordinated convertible debentures upon the completion of the acquisition of Viking on February 3, 2006. The Debentures are governed by the terms of the Debenture Indenture. These Debentures are convertible into fully paid and non-assessable Trust Units, at the option of the holder, at any time prior to the close of business on the earlier of the maturity date and the business day immediately preceding the date specified by the Trust for redemption. The conversion price per Trust Units is specified for each series.

On June 30, 2004, Harvest Operations issued 600,587 Exchangeable Shares to former shareholders of Storm Energy Inc. who were residents of Canada and elected to receive such shares. The Exchangeable Shares were exchangeable into Trust Units at a pre-determined ratio which was increased for each distribution made by the Trust subsequent to June 30, 2004. The Exchangeable Shares were provided equivalent voting rights as those of Unitholders through an agreement pursuant to which the holders of Exchangeable Shares could direct the Trustee to vote at meetings of Unitholders. After retractions of 145,040 shares in 2004, 272,578 shares in 2005 and 156,067 shares in 2006, Harvest Operations elected on March 16, 2006 to exercise its de minimus redemption right to redeem all of the remaining Exchangeable Shares outstanding on June 22, 2006 for a cash payment totalling $1.0 million following which there were no Exchangeable Shares outstanding.

The Trust Indenture allows for the creation of an unlimited number of Special Voting Units to enable the Trust to effect exchangeable securities transactions. Exchangeable securities transactions are commonly used in corporate acquisitions to give the selling securityholder a tax deferred "rollover" on the sale of the securityholder's securities, which may not otherwise be available. In an exchangeable securities transaction the tax event is generally deferred until the exchangeable securities are actually exchanged. Holders of Special Voting Units are not entitled to any distributions of any nature whatsoever from the Trust, but are entitled to such number of votes at meetings of Unitholders as may be prescribed by Harvest's Board in the resolution authorizing the issuance of any Special Voting Units. Except for the right to vote at meetings of the Unitholders, the Special Voting Units shall not confer upon the holders thereof any other rights. As of December 31, 2006, one Special Voting Unit was outstanding having been issued in connection with Harvest Operations of Exchangeable Shares on June 30, 2004 none of which are outstanding as of December 31, 2006. This Special Voting Unit was subsequently cancelled.

Trust Units and the Trust Indenture

Effective upon the amendment and restatement of the Trust Indenture which occurred concurrent with the closing of the Viking Arrangement on February 3, 2006, the Trust is authorized to issue three classes of Trust Units, described and designated as Ordinary Trust Units, Special Trust Units and Special Voting Units, pursuant to the amended and restated Trust Indenture. Each Ordinary Trust Unit entitles the holder or holders thereof to one vote at any meeting of the unitholders and each Special Trust Unit shall entitle the holder or holders thereof to three-sixteenths of one vote at any meeting of the unitholders. The Special Trust Units were created and issued to enable the closing of the Viking Arrangement and all have been subsequently cancelled. Unless otherwise specifically designated as such, all references to Trust Units are deemed to be references to Ordinary Trust Units.

As of March 20, 2007, there were 130,069,755 Trust Units (122,096,172 Trust Units at December 31, 2006) issued and outstanding. Each Trust Unit entitles the holder thereof to one vote at any meeting of the holders of Trust Units and represents an equal undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding-up of the Trust. All Trust Units shall rank among themselves equally and rateably without discrimination, preference or priority. Each Trust Unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the Trust Units held by such holder (see "Redemption Right" below). See "Risk Factors – Risks Related to Harvest's Structure Nature of Trust Units".

The Trust Indenture also provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or 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 Harvest Operations 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 Harvest Operations may determine.

The Trust Units do not represent a traditional investment and should not be viewed by investors as "shares" in the Trust. Corporate law does not govern the Trust and the rights of Unitholders. As holders of Trust Units in the Trust, the 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 rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act (Canada)*, the *Companies' Creditors Arrangement Act (Canada)*, and in some cases, the *Winding Up and Restructuring Act (Canada)*. As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation.

The following is a summary of certain provisions of the Trust Indenture and the Trust Units. For a complete description, reference should be made to the Trust Indenture, as may be subsequently amended and superseded, a copy of which may be viewed at the offices of, or obtained from, the Trustee and a copy of which has been filed on www.sedar.com.

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. The provinces of Alberta and Ontario have recently passed legislation providing Unitholders of mutual fund trusts the same protections afforded shareholders of corporations. See "RISK FACTORS – Risks Related to Harvest's Structure Unitholder Limited Liability".

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" (as defined in the Trust Indenture) 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.

The Trust Indenture imposes limitations on the amount of cash consideration the Trust may pay out for the Trust Units tendered for redemption and also provides for the determination of the value of the Market Redemption Price payable if the Trust Units are not listed for trading on the TSX or any other stock exchange. The details of these provisions can be reviewed in further detail in the Trust Indenture filed at www.sedar.com.

It is anticipated that this Redemption Right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Promissory notes of Harvest Operations or the Trust 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 notes. Such 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 Ownership

The Trust Indenture provides that it is intended that the Trust qualify as a "unit trust" and a "mutual fund trust" under the Tax Act. For the Trust to qualify as a "mutual fund trust" for the purposes of the Tax Act, it is required that, among other things, (i) the Trust not be considered to be a trust established or maintained primarily for the benefit of non-residents of Canada; or (ii) the Trust satisfies certain conditions as to the nature of the assets of the Trust as specified in the Tax Act (the "**Asset Test**"). Harvest believes that the Trust has at all material times satisfied the Asset Test and accordingly, for purposes of the Tax Act, the Trust should qualify as a "mutual fund trust".

In addition, Harvest, with the assistance of its transfer agent and registrar for the Trust Units, Valliant Trust Company, maintains a process of soliciting participant declaration forms from all registered holders of its Trust Units. The participation declaration forms requires the certification of the number of Trust Units held by non-residents of Canada and the number of non-residents holders, all as defined by the Tax Act. This process includes the solicitation of such forms by the Canadian Depository for Securities and, indirectly, the Depository Trust company. At the end of each quarter, Harvest instructs Valiant Trust Company to complete this solicitation process and report the results. As at December 31, 2006, the non-resident holders of Trust Units represented approximately 54% of the Trust's issued and outstanding Trust Units.

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 Harvest Operations pursuant to the Trust Indenture and the Administration Agreement. 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 cash distributions paid to Unitholders, although the calculation of the amount of the distribution shall be made by Harvest Operations and approved by the Harvest Board;

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

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

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

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

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

The Trustee is required under the Trust Indenture to exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith and in the best interests of the Trust and the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

At each annual meeting, the Unitholders shall reappoint or appoint a successor to the Trustee at the annual meeting of Unitholders. The Trustee may also be removed by Harvest Operations upon delivery of a notice in writing Harvest Operations 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 Harvest Operations, or any other person to whom the Trustee has, with the consent of Harvest Operations, 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 Harvest Operations 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.

Delegation of Authority, Administration and Governance

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

Harvest Operations currently has a board of directors consisting of 8 individuals, and has presented a slate of 8 directors to the Unitholders at the 2007 Annual Meeting. Pursuant to the Trust Indenture, Unitholders are entitled to elect the Board of Directors annually. Prior to all annual meetings, Harvest Operations will deliver an information circular and form of proxy to Unitholders with respect to the election of the directors of Harvest Operations at any such meeting.

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

In exercising its powers and discharging its duties, Harvest Operations 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. Harvest Operations' 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, Harvest Operations employs and will continue to employ prudent oil and natural gas business practices. All of Harvest Operations' 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 Harvest Operations by the Trust and the costs of providing such services.

General and administrative costs are deducted from production revenues in computing income from the Net Profits Interest to the extent not paid from the residual income of Harvest Operations or deducted by the Trust in determining cash available for distribution to Unitholders. General and administrative costs are generally charged to the Trust by Harvest Operations based on direct costs incurred in fulfilling the obligations of Harvest Operations to the Trust pursuant to the Trust Indenture and the Administration Agreement. Harvest Operations 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.

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, 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 Harvest Operations and the appointment of the auditors of the Trust.

A meeting of Unitholders may be convened at any time and for any purpose by Harvest Operations 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.

Take-Over Bid

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

Termination of the Trust

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

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

Reporting to Unitholders

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

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, Harvest Operations and any other subsidiary of the Trust; to enter into any other obligations on behalf of the Trust; or enter into any subordination agreement on behalf of the Trust or any other person, and to assign, charge, pledge, hypothecate, convey, transfer, mortgage, subordinate, and grant any security interest, mortgage or encumbrance over or with respect to all or any of the Trust Fund or to subordinate the interests of the Trust in the Trust Fund to any other person. Debt service costs incurred by the Trust are deducted in determining the cash available for distribution to Uniholders.

Debentures and the Debenture Indenture

The following is a summary of the material attributes and characteristics of the Debentures. This summary does not, however, include a description of all of the terms of each series of Debentures, and reference should be made to the respective Debenture Indenture filed at www.sedar.com for a complete description of such terms.

General

The Debentures are issued under the Debenture Indenture. The Trust may, however, from time to time, without the consent of the holders of the Debentures but subject to the limitations described herein, issue additional debentures of the same series or of a different series under the Debenture Indenture. The Debentures are issuable only in denominations of $1,000 and integral multiples thereof.

Each series of Debentures will specify a maturity date, an interest rate, the terms of the conversion privilege and the redemption terms, if any. The principal amount of the Debentures will be payable in lawful money of Canada or, at the option of the Trust and subject to applicable regulatory approval, by payment of Units as further described under "- Payment upon Redemption or Maturity" and "- Redemption and Purchase". The interest on the Debentures will be payable in lawful money of Canada including, at the option of the Trust and subject to applicable regulatory approval, in accordance with the Unit Interest Payment Election as described under "Interest Payment Option".

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

Conversion Privilege

Each Debenture is convertible at the holder's option into fully paid and non-assessable Units at any time prior the earlier of the Final Maturity Date and the Business Day immediately preceding the date specified by the Trust for redemption of the Debentures at a specified conversion price. No adjustment will be made for distributions on Units issuable upon conversion or for interest accrued on Debentures surrendered for conversion; however, holders converting their Debentures will receive accrued and unpaid interest thereon.

Subject to the provisions thereof, the Debenture Indenture will provide for the adjustment of the specified conversion price in certain events including: (a) the subdivision, redivision or consolidation, reduction or combination of the outstanding Units; (b) the distribution of Units to holders of Units by way of distribution or otherwise other than an issue of securities to holders of Units who have elected to receive distributions in securities of the Trust in lieu of receiving cash distributions paid in the ordinary course; (c) the issuance of options, rights or warrants to holders of Units entitling them to acquire Units or other securities convertible into Units at less than 95% of the then current market price (as defined below under "**Payment upon Redemption or Maturity**") of the Units; and (d) the distribution to all holders of Units of any securities or assets (other than cash distributions and equivalent distributions in securities paid in lieu of cash distributions in the ordinary course). There will be no adjustment of the specified conversion price in respect of any event described in (b), (c) or (d) above if the holders of the Debentures are allowed to participate as though they had converted their Debentures prior to the applicable record date or effective date. The Trust will not be required to make adjustments in the specified conversion price unless the cumulative effect of such adjustments would change the conversion price by at least 1%.

In the case of any reclassification or capital reorganization (other than a change resulting from consolidation or subdivision) of the Units or in the case of any consolidation, amalgamation, arrangement or merger of the Trust with or into any other entity, or in the case of any sale or conveyance of the properties and assets of the Trust as, or substantially as, an entirety to any other entity, or a liquidation, dissolution or winding-up of the Trust, the terms of the conversion privilege shall be adjusted so that each holder of an unsecured subordinated convertible debenture shall, after such reclassification, capital reorganization, consolidation, amalgamation, merger, sale, conveyance, liquidation, dissolution or winding up, be entitled to receive the number of Units or other securities or property such holder would be entitled to receive if on the effective date thereof, it had been the registered holder of the number of Units into which the Debenture was convertible prior to the effective date of such reclassification, capital reorganization, consolidation, amalgamation, merger, sale, conveyance, liquidation, dissolution or winding up.

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

Redemption and Purchase

The Debentures may be redeemable after a specified date and prior to maturity in whole or in part from time to time at the option of the Trust on not more than 60 days and not less than 30 days prior notice as specified for each series of Debentures plus accrued and unpaid interest thereon, if any. In the case of redemption of less than all of a series of Debentures, the Debentures to be redeemed will be selected by the Debenture Trustee on a pro rata basis or in such other manner as the Debenture Trustee deems equitable, subject to the consent of the TSX. The Trust has the right to purchase the Debentures in the market, by tender or by private contract.

Payment upon Redemption or Maturity

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

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

Subordination

The payment of the principal of, and interest on the Debentures will be subordinated in right of payment, as set forth in the Debenture Indenture, to the prior payment in full of all Senior Indebtedness of the Trust and indebtedness to trade creditors of the Trust. "Senior Indebtedness" of the Trust is defined in the Debenture Indenture as the principal of and premium, if any, and interest on and other amounts in respect of all indebtedness of the Trust or any subsidiary of the Trust (whether outstanding as at the date of the Indenture or thereafter incurred), other than indebtedness evidenced by the Debentures and all other existing and future debentures or other instruments of the Trust which, by the terms of the instrument creating or evidencing the indebtedness, is expressed to be *pari passu* with, or subordinate in right of payment to, the Debentures.

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

The Debentures will also be effectively subordinate to claims of creditors of the Trust's subsidiaries except to the extent the Trust is a creditor of such subsidiaries ranking at least *pari passu* with such other creditors. Specifically, the Debentures will be subordinated in right of payment to the prior payment in full of all indebtedness under the Credit Facilities and the Existing Debentures.

Priority over Trust Distributions

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

Change of Control of the Trust

Within 30 days following the occurrence of a change of control of the Trust involving the acquisition of voting control or direction over 66 2/3% or more of the Trust Units (a "**Change of Control**"), the Trust will be required to make an offer in writing to purchase all of the Debentures then outstanding (the "**Debenture Offer**"), at a price equal to 101% of the principal amount thereof plus accrued and unpaid interest (the "**Debenture Offer Price**"). The Debenture Indenture provides that a change of control does not include a merger, reorganization, combination or other similar transaction if the previous holders of Trust Units and securities convertible or carrying the right to acquire Trust Units hold at least 50% of the voting control or direction in such merged, reorganized, combined or other continuing entity.

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

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

Restrictions on Certain Transactions

The Debenture Indenture contains provisions to the effect that subject to the discussion under "Offers for Debentures" below, the Trust shall not enter into any transaction or series of transactions whereby all or substantially all of its undertaking, property or assets would become the property of any other person (herein called a "**Successor**") whether by way of reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise, unless, among other things prior to or contemporaneously with the consummation of such transaction the Trust and the Successor shall have executed such instruments and done such things as are necessary or advisable to establish that upon the consummation of such transaction the Successor will have assumed all the covenants and obligations of the Trust under the Debenture Indenture in respect of the Debentures and the Debentures will be valid and binding obligations of the Successor entitling the holders thereof, as against the Successor, to all the rights of Debentureholders under the Debenture Indenture.

Interest Payment Option

The Trust may elect, from time to time, to satisfy its obligation to pay all or any part of the interest on the Debentures (the "**Interest Obligation**"), on the date it is payable under the Debenture Indenture (an "**Interest Payment Date**"), by delivering sufficient Units to the Debenture Trustee to satisfy all or any part, as the case may be, of the Interest Obligation in accordance with the Debenture Indenture (the "**Unit Interest Payment Election**").

The Debenture Indenture provides that, upon such election, the Debenture Trustee shall (a) accept delivery from the Trust of Units, (b) accept bids with respect to, and consummate sales of, such Units, each as the Trust shall direct in its absolute discretion, (c) invest the proceeds of such sales in short-term permitted government securities (as defined in the Indenture) which mature prior to the applicable Interest Payment Date, and use the proceeds received from such permitted government securities, together with any proceeds from the sale of Units not invested as aforesaid, to satisfy the Interest Obligation, and (d) perform any other action necessarily incidental thereto.

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

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

Events of Default

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

Offers for Debentures

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

Modification

The rights of the holders of the Debentures issued under the Debenture Indenture may be modified in accordance with the terms of the Debenture Indenture. For that purpose, among others, the Debenture Indenture will contain certain provisions which will make binding on all Debenture holders resolutions passed at meetings of the holders of Debentures by votes cast thereat by holders of not less than 66 2/3% of the principal amount of the Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66 2/3% of the principal amount of the Debentures then outstanding. In certain cases, the modification will, instead or in addition, require assent by the holders of the required percentage of Debentures of each particularly affected series.

Limitation on Issuance of Additional Debentures

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

Premium Distribution™, Distribution Reinvestment and Optional Trust Units Purchase Plan ("DRIP Plan")

The Trust has adopted the DRIP Plan which is available to eligible Unitholders (the DRIP Plan is not currently available to residents of the United States). The DRIP Plan provides eligible holders of Trust Units the means of accumulating additional Trust Units by reinvesting cash distributions. At the discretion of Harvest Operations, Trust Units will be 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 record date applicable to such distribution payment, and the second Business Day immediately prior to the distribution payment date on which at least a board lot of Trust Units is traded).

Effective August 23, 2005, the DRIP Plan includes a unique feature which allows eligible Unitholders to elect, under the Premium Distribution™ component of the DRIP Plan, to deliver Trust Units which have been received pursuant to the distribution reinvestment component of the DRIP Plan to a designated broker in exchange for a premium cash distribution equal to 102% of the cash distribution that such Unitholders would have otherwise been entitled to receive on the applicable distribution date (subject to a proration in certain events under the DRIP Plan). Canaccord Capital Corporation has been designated as the plan broker under the Premium Distribution™ component of the DRIP Plan.

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 up to $100,000 aggregate amount of remittances by a Unitholder in any calendar month and a minimum of $5,000 per remittance; provided that the total number of Trust Units that may be issued each fiscal year pursuant to optional cash payments is restricted to not more than 2% of the number of issued and outstanding Trust units at the commencement of that year. As at March 20, 2007, 10,658,967 Trust Units have been issued from treasury since February 15, 2003 as a result of Unitholder participation in the DRIP Plan with proceeds of approximately $281.4 million.

Stability Ratings

Dominion Bond Rating Services Limited ("**DBRS**") maintains a stability rating system for income funds to provide an indication of both the stability and sustainability of cash distributions per trust unit, which is essentially an assessment of an income fund's ability to generate sufficient cash to pay out a stable level of distributions on a per unit basis over the longer term. The DBRS stability ratings provide opinions and research on funds related to the stability and sustainability of distributions over time and are not a recommendation to buy, sell or hold the trust units. In determining a DBRS stability rating, the following factors are evaluated: (1) operating characteristics, (2) asset quality, (3) financial profile, (4) diversification, (5) size and market position, (6) sponsorship/governance, and (7) growth. The rating categories range from STA-1 being the highest stability and sustainability of distributions per unit to STA-7 being poor stability and sustainability with each category refined into further subcategories of high, middle and low providing a total of 21 possible rating categories.

On May 13, 2005, DBRS initiated coverage of the Trust and assigned a stability rating of STA-6 (high) citing its strengths as a steady distribution since inception, a conservative payout ratio of 52% of operating cash flow in 2004, the acquisition of the 19,000 BOE/d of production in September of 2004 as positive in diversifying its production mix and reserve base and management's hedging of 50% to 75% of its net production to reduce cash flow volatility. While recognizing favourable oil price outlook for 2006, DBRS noted the Trust's challenges as high balance sheet leverage, average production decline rates of 22% combined with low capital spending placing increasing reliance on purchasing reserves in a competitive acquisition market and a significant proportion of heavy oil production which have generally higher operating costs and is subject to price differential risk.

On June 29, 2006, DBRS upgraded the stability rating of the Trust to STA-5 (low) following its merger with Viking. Based on its ranking as the fifth largest oil and gas trust, DBRS cited the increased size of core operating areas as providing operating efficiencies and improved access to field services which are in tight supply in western Canada. In addition, DBRS noted the Trust's strengths as a high degree of control over costs with its operated properties representing 85% of total production, the retention of senior Viking management with expertise in heavy oil production complementing its significant heavy oil assets, a larger asset base providing greater access to more favourable lending terms and an active hedging program ensuring some cash flow certainty. The Trust rating also reflected a below average reserve life index among DBRS-rated trusts, an 80% to 85% payout ratio which is high compared to its peers and a continued reliance on acquisitions to maintain its long term asset base.

Following its announcement of the acquisition of Birchill and equity financing on July 26, 2006, DBRS confirmed the STA-5 (low) rating of the Trust noting the high cost of the acquisition as reflective of a broader industry trend with more emphasis placed on probable reserves in evaluating acquisitions in a highly competitive environment. In addition, DBRS recognized that the Birchill properties fit well with the Trust's existing assets providing a high degree of certainty regarding expectation of future performance and that the 50:50 debt and equity financing should result in a modest decline in the Trust's payout ratio.

On August 23, 2006, DBRS placed the stability rating of Harvest "Under Review with Negative Implications" following its proposed acquisition of North Atlantic citing the multiple paid as likely being at the height of the market. DBRS also noted that the North Atlantic refinery is well located with ready access to the eastern United States finished products markets as well as crude oil supply sources globally while recognizing that the vertical integration provides cash flow diversification, additional opportunities to achieve growth and creates a much large entity which should lead to greater financial resources, liquidity and a lower average cost of capital over time. The rating action reflects (1) the initially debt funded transaction would result in a substantially higher debt to capital and debt to cash flow ratios; (2) Harvest's limited expertise in the refining segment which is a highly cyclical business with significant margin volatility; and, (3) the North Atlantic refinery is relatively small and a single asset in an industry that is increasingly focused on scale to achieve cost advantages and market presence.

On November 1, 2006, DBRS placed the stability ratings of select Canadian income trusts "Under Review with Developing Implications" following the Federal Minister of Finance's announcement to make significant changes to the way in which Canadian income trusts will be taxed in the future. For income trusts that plan to reduce the level of their distributions to unitholders to reflect the additional tax burden, the reduction would be viewed as a one time event and DBRS's analytical focus would then be on the stability and sustainability of distributions following the adjustments. Under this scenario, the stability ratings would likely be confirmed; however, the proposed legislation could encourage certain trusts to develop alternative capitalization or operating strategies. Until DBRS is able to discuss these issues with those trusts implementing alternative capitalization or operating strategies, their ratings would remain under review. Harvest's stability rating would also be subject to this latest "Under Review with Developing Implications" rating adjustment.

MARKET FOR SECURITIES

The Trust Units are listed and traded on the TSX and the New York Stock Exchange ("**NYSE**"). The trading symbol on the TSX for the Trust Units is "HTE.UN", and on the NYSE is "HTE". The Trust has issued three series of unsecured subordinated debentures which trade on the TSX under the symbols "HTE.DB" for the 9% Debentures Due 2009, "HTE.DB.A" for the 8% Debentures Due 2009, "HTE.DB.B" for the 6.5% Debentures Due 2010, "HTE.DB.E" for the 7.25% Debentures Due 2013 and "HTE.DB.F" for the 7.25% Debentures Due 2014. In addition, pursuant to the Viking Arrangement, the Trust assumed the two outstanding series of convertible debentures that Viking had outstanding as of February 3, 2006. These debentures trade on the TSX under the symbols "HTE.DB.C" ("VKR.DB" prior to the Viking Arrangement) for the 10.5% Debentures Due 2008 and "HTE.DB.D" ("VKR.DB.A" prior to the Viking Arrangement) for the 6.4% Debentures Due 2012. The trading history for each of the series of debentures is presented below.

The following sets forth the price range and consolidated trading volume of the Trust Units on the TSX and the NYSE for the periods indicated.

	TSX Price Range			NYSE Price Range		
	High	Low	Volume	High	Low	Volume
2006						
January	$38.51	$36.51	4,284,479	$33.50	$31.73	3,275,300
February	$37.99	$32.06	9,809,410	$33.17	$27.75	8,056,800
March	$34.83	$32.10	13,561,855	$30.13	$28.00	6,589,100
April	$35.83	$33.71	8,547,311	$31.50	$28.96	5,095,700
May	$35.18	$31.22	12,099,146	$31.78	$28.00	7,424,500
June	$34.44	$28.84	9,782,528	$31.25	$26.05	7,943,900
July (1)	$34.43	$32.30	9,524,720	$30.44	$28.60	6,372,800
August	$34.85	$33.07	14,579,844	$31.15	$29.41	11,285,700
September	$34.84	$28.02	19,233,640	$31.52	$25.07	13,936,800
October	$33.12	$27.10	17,327,408	$29.49	$24.00	13,379,000
November	$29.90	$24.64	29,031,801	$26.55	$21.70	33,322,600
December	$27.02	$25.44	8,129,854	$23.55	$21.90	15,547,600
2007						
January	$26.22	$23.20	12,822,502	$22.20	$19.70	16,693,600
February	$27.49	$24.81	10,036,635	$23.55	$21.18	10,059,454
March (1-20)	$28.55	$25.96	6,437,281	$24.25	$21.97	7,564,850

The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 9% Debentures Due 2009 as reported by the TSX under the symbol "HTE.DB" for the periods indicated.

2006	High	Low	Close	Volume
January	$266.77	$264.47	$265.00	270
February	No trades	No trades	No trades	-
March	No trades	No trades	No trades	-
April	$240.07	$240.07	$240.07	250
May	$242.91	$228.00	$228.00	460
June	$228.00	$220.02	$227.75	500
July	$238.51	$238.51	$238.51	100
August	$250.00	$241.32	$241.32	280
September	No trades	No trades	No trades	-
October	No trades	No trades	No trades	-
November	No trades	No trades	No trades	-
December	$193.50	$186.00	$186.00	770

2007				
January	$180.99	$173.00	$180.99	140
February	$190.02	$176.01	$178.32	760
March (1-20)	$193.10	$193.10	$193.10	100

The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 8% Debentures Due 2009 as reported by the TSX under the symbol "HTE.DB.A" for the periods indicated.

2006	High	Low	Close	Volume
January	$237.00	$229.00	$231.65	1,510
February	$249.00	$233.00	$249.00	750
March	$215.00	$206.77	$215.00	1,775
April	$220.00	$205.11	$220.00	400
May	$220.00	$218.00	$218.00	630
June	$204.97	$189.44	$195.00	980
July	$208.00	$195.00	$208.00	200
August	$211.46	$205.00	$211.46	860
September	$206.24	$195.53	$195.53	300
October	$202.84	$184.48	$195.02	2,710
November	$175.00	$160.02	$165.00	2,290
December	$166.78	$162.00	$166.62	860
2007				
January	No trades	No trades	No trades	-
February	$170.00	$156.66	$170.00	1,600
March (1-20)	$165.02	$165.02	$165.02	100

The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 6.5% Debentures Due 2010 as reported by the TSX under the symbol "HTE.DB.B" for the periods indicated.

2006	High	Low	Close	Volume
January	$123.25	$118.71	$121.00	12,360
February	$120.68	$107.74	$108.75	34,210
March	$111.70	$107.50	$110.70	15,580
April	$115.00	$109.92	$110.95	15,170
May	$112.00	$106.00	$109.32	21,940
June	$111.70	$103.00	$108.25	62,540
July	$109.00	$106.87	$108.50	3,740
August	$112.00	$107.98	$110.05	13,040
September	$112.30	$102.72	$104.04	54,440
October	$107.50	$101.00	$106.25	65,130
November	$102.70	$96.00	$99.80	55,640
December	$100.00	$98.75	$99.99	21,140
2007				
January	$100.00	$96.00	$100.00	10,635
February	$102.69	$93.26	$99.25	18,710
March (1-20)	$102.49	$98.50	$100.20	6,290

The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 10.5% Debentures Due 2008 as reported by the TSX under the symbol "HTE.DB.C" for the periods indicated.

2006	High	Low	Close	Volume
January[1]	$131.75	$125.60	$127.45	11,060
February	$125.00	$112.99	$125.00	1,510
March	$119.00	$111.58	$118.07	2,450
April	$123.00	$116.14	$120.00	2,790
May	$119.91	$100.08	$116.00	4,540
June	$118.00	$103.00	$115.00	8,250
July	$118.00	$110.42	$118.00	4,060
August	$120.00	$113.00	$115.50	55,990

2006	High	Low	Close	Volume
September	$120.00	$103.00	$107.32	3,610
October	$114.00	$104.02	$111.96	9,320
November	$113.18	$102.50	$105.30	7,650
December	$105.75	$105.01	$105.50	1,760
2007				
January	$105.50	$103.25	$105.00	1,650
February	$106.00	$103.50	$105.00	4,530
March (1-20)	$104.50	$103.00	$103.23	3,060

Note:

(1) Traded as VKR.DB during this period, and assumed by Harvest effective February 3, 2006

The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 6.4% Debentures Due 2012 as reported by the TSX under the symbol "HTE.DB.D" for the periods indicated.

2006	High	Low	Close	Volume
January[1]	$104.99	$102.52	$103.50	73,950
February	$104.00	$101.50	$102.85	47,430
March	$103.49	$102.00	$102.95	61,550
April	$103.69	$100.55	$100.61	53,440
May	$102.00	$97.01	$99.66	69,650
June	$100.45	$98.00	$100.45	46,310
July	$100.99	$99.62	$100.25	27,600
August	$101.00	$99.25	$99.50	36,190
September	$100.50	$99.00	$99.70	44,030
October	$100.90	$97.51	$99.00	43,250
November	$98.03	$90.02	$90.50	63,950
December	$91.99	$90.25	$91.25	61,010
2007				
January	$92.00	$90.34	$91.30	45,600
February	$98.49	$90.76	$96.01	45,760
March (1-20)	$97.50	$92.53	$94.69	20,810

Note:

(1) Traded as VKR.DB during this period, and assumed by Harvest effective February 3, 2006.

The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 7.25% Debentures Due 2009 subsequent to their issue on November 22, 2006 as reported by the TSX under the symbol "HTE.DB.E" for the periods indicated.

2006	High	Low	Close	Volume
November (22-30)	$98.25	$97.00	$97.99	216,560
December	$99.00	$97.00	$99.00	359,210
2007				
January	$99.00	$95.00	$96.15	231,410
February	$98.97	$96.00	$98.35	364,150
March (1-20)	$99.69	$96.50	$99.44	146,090

The 7.25% Debentures Due 2014 issued on February 1, 2007 are listed for trading on the TSX under the symbol "HTE.DB.F". The following table sets forth the high, low and closing trading prices and the aggregate trading volume of these Debentures subsequent to their issue as reported by the TSX under the symbol "HTE.DB.F" for the periods indicated.

	High	Low	Close	Volume
2007				
February	$105.75	$99.75	$103.50	573,990
March (1-20)	$106.50	$102.00	$106.00	224,680

DIRECTORS AND OFFICERS OF HARVEST OPERATIONS CORP.

The names, municipalities of residence, present positions with Harvest Operations and principal occupations during the past five years of the directors and officers of Harvest Operations are set out in the table below.

Name and Municipality of Residence	Position with Harvest Operations	No. of Trust Units Held [1]	Principal Occupation
Kevin A. Bennett[4] Calgary, Alberta	Director	513,735	Professional engineer; independent businessman involved in founding and the directorship of several oil and gas, and energy services companies. Co-founded Harvest Energy Trust in 2002 with Mr. Chernoff. From Sept. 1998 to Sept. 2001, was President, Chief Operating Officer and a director of Ventus Energy Ltd. (a public oil and gas company).
John A. Brussa [3][5] Calgary, Alberta	Director	376,528	Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP (a law firm).
M. Bruce Chernoff [3][5] Calgary, Alberta	Director, Chairman	6,442,238[6]	Professional Engineer; Chairman of Harvest Operations; 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. (a public oil and natural gas company).
Verne G. Johnson[2] Calgary, Alberta	Director	60,381	Independent businessman since January 2000; Senior Vice President, Funds Management of Enerplus Resources Group (a public oil and natural gas trust) from 2000 to 2002.
Hector J. McFadyen[2] Calgary, Alberta	Director	55,329	Independent businessman and Director of Hunting PLC (a public UK based international oil services 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); formerly, President, Midstream Division, Alberta Energy Company Ltd. (now EnCana Ltd., a public oil and natural gas company) until 2002.
Dale Blue[2][7] Mississauga, Ontario	Director	20,373	Independent consultant; until 2001, Chairman, President & Chief Executive Officer of Chase Manhattan Bank of Canada (a financial services company), and Managing Director of Chase Manhattan Bank in New York (a financial services company); over thirty years experience in financial services, has served on numerous domestic and international Boards.

Name and Municipality of Residence	Position with Harvest Operations	No. of Trust Units Held [1]	Principal Occupation
David J. Boone[4] [7] Calgary, Alberta	Director	11,644	Professional Engineer; President, Escavar Energy Inc. (a private oil and natural gas company); prior thereto, Executive Vice President of EnCana Corporation (a public oil and natural gas company) and President of EnCana's Offshore and International Operations division, 2002 – 2003; prior thereto, Executive Vice-President and Chief Operating Officer of PanCanadian Petroleum (a public oil and natural gas company), 2000 – 2002; prior thereto, various positions with Imperial Oil (a public oil and natural gas company); also Vice-Chair, Canadian National Committee of the World Petroleum Congress.
William Friley[3][5] [7] Calgary, Alberta	Director	24,686	President and Chief Executive Officer of Telluride Oil and Gas Ltd. (a private oil and natural gas company), President of Skyeland Oils Ltd. (a private oil and natural gas company), Director of Mustang Resources Inc. (a public oil and natural gas company), and Chairman of TimberRock Energy Corporation (a private oil and natural gas company); Prior thereto, President and Chief Executive Officer of Triumph Energy Corporation (a public oil and natural gas company).
John Zahary[8] Calgary, Alberta	President & CEO	77,799[9]	Professional Engineer, President and Chief Executive Officer of Harvest Operations since February 2006. Prior thereto, President and Chief Executive Officer of VHI (a public oil and natural gas trust) since May 11, 2004; President of Petrovera Resources (a private oil and natural gas company) from June 1999 to March 2004.
Robert Fotheringham[8] Calgary, Alberta	Chief Financial Officer	23,393	Chartered Accountant, Chief Financial Officer of Harvest Operations since February 2006. Prior thereto was Vice President, Finance and Chief Financial Officer of VHI since June, 2004; Chief Financial Officer of Inter Pipeline Fund (a public pipeline limited partnership) from February 2003 to April 2004; Chief Financial Officer of True North Energy Corporation (a private oil sands development company) from November 2001 to January 2003.
Rob Morgan[8] Calgary, Alberta	Chief Operating Officer - Upstream	27,330	Professional Engineer, Chief Operating Officer - Upstream of Harvest Operations since February, 2006. Prior thereto was Vice President, Operations and Corporate Development of VHI since June, 2004; Manager, Planning at Canadian Natural Resources Limited (a public oil and natural gas company) from March 2004 to June 2004; Vice President Corporate Development, and Vice President Engineering of Petrovera Resources (a private oil and natural gas company) from May 1999 to March 2004.
Jacob Roorda[8] Calgary, Alberta	Vice President, Corporate	347,330[10]	Professional Engineer, Vice President, Corporate of Harvest Operations since February 2006. Prior thereto was President of Harvest Operations since August 2002; from June 1999 to July 2002, Managing Director, Research Capital (a mid-sized investment banking dealer).

Name and Municipality of Residence	Position with Harvest Operations	No. of Trust Units Held (1)	Principal Occupation
Gary Boukall Calgary, Alberta	Vice President, Geosciences	13,193	Professional Geologist; On March 16, 2007, appointed Vice President, Geosciences of Harvest Operations; from December 2002 to March 2007 held various senior technical and management positions with Harvest Operations; Prior thereto was a lead geologist at Burlington Resources Ltd.
James Sheasby Calgary, Alberta	Vice President, Engineering	nil	Professional Engineer; On March 16, 2007 appointed Vice President, Engineering of Harvest Operations; from February 2, 2006 to March 2007 was Manager, Engineering of Harvest Operations; from November 2005 to February 2, 2006 was Manager Engineering of Viking Holdings; from November 2004 to October 2005 was Vice President, Engineering of Hygait Resources; from February 2004 to October 2004 was an Exploitation Engineer at Canadian Natural Resources Ltd.; Prior thereto was a Team Lead at Petrovera Resources.
Neil Sinclair Calgary, Alberta	Vice President, Operations	11,078(11)	On March 16, 2007 appointed Vice President, Operations of Harvest Operations; from February 2, 2006 to March 2007 was Manager, Operations of Harvest Operations; from June 9, 2004 to February 2, 2006 was Manager Operations of Viking Holdings Inc.; from February 2004 to June 9, 2004 was Manager of Technical Services at PennWest Petroleum Ltd.; Prior thereto was Manager, Operations at Petrovera Resources.
Phillip L. Reist Calgary, Alberta	Vice President, Controller	5,607	Chartered Accountant; On March 16, 2007 appointed Vice President, Controller of Harvest Operations. From February 2, 2006 to March 16, 2007 was the Controller of Harvest Operations; Controller of Viking Holdings from September 12, 2005 to February 2, 2006; Vice President, Controller of PennWest Petroleum Ltd. from March 2004 to June 2005; and prior thereto was Vice President, Finance and Controller of Petrovera Resources.
David J. Rain(8) Calgary, Alberta	Corporate Secretary	58,164	Chartered Accountant; Corporate Secretary of Harvest Operations since February 2006 and since June 1999, Vice President Finance and Chief Financial Officer and a Director of Caribou Capital Corp. (an investment management company) since June 1999. Previously was Vice President and Chief Financial Officer of Harvest Operations since July 2004; prior thereto Vice President, Finance and Chief Financial Officer of Petrobank (a public oil and natural gas company) from October 2001 to March 2004.
Steven Saunders(8) Calgary, Alberta	Assistant Corporate Secretary and Director of Taxation	3,196	Chartered Accountant; On March 16, 2007, was appointed Assistant Corporate Secretary and relinquished the Treasurer role. Was appointed Treasurer of Harvest Operations on February 2, 2006 and Director of Taxation of Harvest Energy Trust since November 2004; Prior thereto was International Tax Analyst with EnCana Corporation.

Name and Municipality of Residence	Position with Harvest Operations	No. of Trust Units Held (1)	Principal Occupation
Dean Beacon Calgary, Alberta	Treasurer	nil	Appointed Treasurer of Harvest Operations on March 16, 2007; Prior thereto was a Senior Advisor, Corporate Finance at Talisman Energy Inc.

Notes:

(1) Represents all Trust Units held directly or indirectly or over which such person exercises control or direction as at March 20, 2007. Based upon information provided by the director or officer to the Trust.
(2) Member of the Audit Committee.
(3) Member of the Corporate Governance Committee.
(4) Member of the Reserves, Safety and Environment Committee.
(5) Member of the Compensation Committee.
(6) Includes Trust Units held by entities controlled by Mr. Chernoff, and Trust Units held in RESP accounts for the benefit of Mr. Chernoff's children.
(7) Appointed as a director on February 3, 2006 following the completion of the Viking Arrangement.
(8) Effective February 3, 2006 the following changes were made to Harvest Operations' Officers: John Zahary, former President & Chief Executive Officer of Viking became President & Chief Executive Officer of Harvest Operations; Robert Fotheringham, former Vice President, Finance & Chief Financial Officer of Viking became Vice President, Finance & Chief Financial Officer of Harvest Operations; Rob Morgan, former Vice President, Operations & Chief Operating Officer of Viking became Vice President, Engineering and Chief Operating Officer of Harvest Operations; Jacob Roorda, former President of Harvest Operations became Vice President, Corporate; David Rain, former Vice President, Finance & Chief Financial Officer of Harvest Operations became Corporate Secretary; Steve Saunders became Treasurer and Director of Taxation.
(9) Includes 2,902 Trust Units held by Mr. Zahary's spouse.
(10) Includes 81,669 Trust Units held by Mr. Roorda's spouse.
(11) Includes 415 Trust Units held by Mr. Sinclair's spouse.
(12) The terms of office of all of the directors will expire at the next annual unitholders' meeting of the Trust.

As at March 20, 2007, the directors, nominated directors and officers of Harvest Operations and their associates and affiliates, as a group, held, directly or indirectly, or exercise control or direction over, approximately 8,072,004 Trust Units or approximately 6.21% of the outstanding Trust Units.

Corporate Cease Trade Orders or Bankruptcies

Mr. John Brussa was a director of Imperial Metals Limited, a corporation engaged in both oil and gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the *Company Act* (British Columbia) and under the *Companies' Creditors Arrangement Act* (Canada) which resulted in the separation of its two businesses and the creation of two public corporations: Imperial Metals Corporation and IEI Energy Inc. (now Rider Resources Ltd.).

Other than the item referenced above, no director, executive officer or unitholder holding a sufficient number of Trust Units to affect materially the control of the Trust has, within the last 10 years, been a director or executive officer of any company 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 company access to any exemption under securities legislation for a period of more than 30 consecutive days; was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade order or similar order or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days; or within a year of ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency 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.

Personal Bankruptcies

No director, executive officer or Unitholder holding a sufficient number of Trust Units to affect materially the control of the Trust has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being 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 the individual.

Penalties or Sanctions

No director, executive officer or Unitholder holding a sufficient number of Trust Units to affect materially the control of the Trust has, within the last 10 years, 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.

Conflicts of Interest

Directors and officers of Harvest Operations may, from to time, be involved with the business and operations of other oil and gas issuers, in which case a conflict may arise. See "Risk Factors". Properties will not be acquired from officers or directors of Harvest Operations 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 Harvest Operations 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 Harvest Operations and the Trust. No assurances can be given that opportunities identified by such board members will be provided to Harvest Operations and the Trust.

LEGAL AND REGULATORY PROCEEDINGS

There are no legal or regulatory proceedings which the Trust or any subsidiary of the Trust is a party or of which any of their property is subject, nor are there any proceedings known to Harvest to be contemplated that involves a claim for damages exceeding ten per cent of our current assets, other than methyl tertiary butyl ether ("**MTBE**") proceedings against North Atlantic in *The State of New Hampshire versus Amerada Hess Corp. et al*, in of more than 100 MTBE product liability litigation cases that have been consolidated for pre-trial purposes in this matter. The plaintiffs seek relief for alleged contamination of ground water from the various defendants' use of the gasoline additive MTBE. Although the plaintiffs have not made a particular monetary demand, they are asserting collective and joint liability against all defendants. All consolidated law suits are at a preliminary stage and, accordingly, it is too early in the legal process to reach any conclusion regarding the ability of the State of New Hampshire to properly assert jurisdiction over North Atlantic in the lawsuit or to reach any conclusions regarding the substance of the plaintiffs' claims. Accordingly, the evaluation of the risk of liability to North Atlantic is not determinable at this time and no amounts are accrued in the combined financial statements in respect of this matter. In addition, Harvest received an indemnity under the Purchase and Sale Agreement from the vendor of the shares of North Atlantic, Vitol Group B.V., in respect of this contingent liability.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and executive officers of the Trust, any person or company that is the direct or indirect beneficial owner, or who exercises control or direction over more than 10% of the outstanding Trust Units, or any known associate or affiliate of such persons or company, in any transaction within the three most recently completed financial years or during the current financial year.

TRANSFER AGENT AND REGISTRAR

Valiant Trust Company, at its principal offices in Calgary, Alberta, is the transfer agent and registrar of the Trust Units, 9% Debentures Due 2009, 8% Debentures Due 2009, 6.5% Debentures Due 2010, 7.25% Debentures Due 2013, and 7.25% Debentures Due 2014. The transfer agent and registrar of the 10.5% Debentures due 2008 and 6.40% Debentures Due 2012 is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by the Trust within the most recently completed financial year, or before the most recently completed financial year but still in effect, are the following:

1. the Trust Indenture between Harvest Operations Corp. and Valiant Trust Company described in "Trust Indenture";

2. the Indenture between Harvest Energy Trust, Harvest Operations Corp. and Valiant Trust Company in connection with the 9% Debentures Due 2009, 8% Debentures Due 2009, 6.5% Debentures Due 2010, 7.25% Debentures Due 2013, and 7.25% Debentures Due 2014 and the Debentures Indenture between Viking energy Royalty Trust and Computershare Trust Company of Canada in connection with the 10.5% Debentures Due 2008 and 6.40% Debentures Due 2012 described in "GENERAL DESCRIPTION OF CAPITAL – and the Debenture Indenture";

3. the Indenture between Harvest Operations Corp., the Subsidiary Guarantors, Harvest Energy Trust and U.S. Bank National Association in connection with the $7^{7/8}$% Senior Notes;

4. CDN$450,000,000 Bridge Credit Agreement dated October 19, 2006;

5. Amended and Restated Credit Agreement dated October 19, 2006; and

6. The Trust's Unit Incentive Plan and Unit Award Incentive Plan.

Copies of each of these documents have been filed on SEDAR at www.sedar.com.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Trust during, or related to, the Trust's most recently completed financial year other than McDaniel, GLJ and Sproule, the Trust's Independent Reserve Engineering Evaluators and KPMG LLP, the Trust's auditors. As at the date hereof, none of the principals of McDaniel, GLJ, and Sproule as a group, directly or indirectly, owned more than 1% of the Units and KPMG LLP has advised Harvest's Audit Committee that they are independent with respect to the Trust within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Trust or of any associate or affiliate of the Trust except for John A. Brussa, a director of Harvest Operations, who is a partner at Burnet, Duckworth & Palmer LLP which law firm renders legal services to Harvest.

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a Canadian issuer listed on the New York Stock Exchange (the "**NYSE**"), we are not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic requirements. As a foreign private issuer, we are only required to comply with three of the NYSE Rules (i) have an audit committee that satisfies the requirements of the *United States Securities Exchange Act of 1934*; (ii) the Chief Executive Officer must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE Rules; and (iii) provide a brief description of any significant differences between our corporate governance practices and those followed by U.S. companies listed under the NYSE. The Trust has disclosed in the corporate governance section of its website at www.harvestenergy.ca that it does not have an internal audit function. Except as described, the Trust is in compliance with the NYSE corporate governance standards in all other significant respects.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of securities and interests of insiders in material transactions, where applicable, is contained in the Trust's Information Circular – Proxy Statement dated March 20, 2007 which relates to Annual Meeting of Unitholders to be held on May 16, 2007. Additional financial information is provided in Harvest's audited consolidated financial statements and notes there to for the year ended December 31, 2006 which may be found on SEDAR at www.sedar.com.

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

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

(a) (ι) proved and proved plus probable oil and natural gas reserves estimated as at December 31, 2006 using forecast prices and costs; and

(b) the related estimated future net revenue; and

(c) (ii) proved oil and natural gas reserves estimated as at December 31, 2006 using constant prices and costs; and

(iii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's and the Trust's other subsidiaries' reserves data. The report of the independent qualified reserves evaluator is presented below.

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

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

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

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

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

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

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

(signed) "John Zahary"
John Zahary
President & CEO

(signed) "Rob Morgan"
Rob Morgan
Vice President, Engineering & COO

(signed) "Kevin Bennett"
Kevin Bennett
Director and Chairman of the RSE Committee

(signed) "David Boone"
David Boone
Director and Member of the RSE Committee

February 28, 2006

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the Board of directors of Harvest Operations Corp. (the "Corporation"):

We have evaluated the Corporation's and Harvest Energy Trust's other subsidiaries' reserves data as at December 31, 2006. The reserves data consist of the following:

(a) (i) Proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and

(b) The related estimated future net revenue; and

(c) (ii) Proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and

(iii) The related estimated future net revenue; and

The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with the principles and definitions presented in the COGE Handbook.

The following table sets forth the estimated future net revenue (before deductions of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs, and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2006. This table also identifies the respective portions thereof that we have evaluated and reported on to the Corporation's Management and Board of directors.

			Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate)($M)			
Independent Qualified Reserves Evaluator or Auditor	Preparation Date of Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
McDaniel and Associates Consultants Ltd.	March 7, 2007	Canada	-	1,186,293	-	1,186,293
GLJ Petroleum Consultants Ltd.	February 23, 2007	Canada	-	1,430,091	-	1,430,091
Sproule Associates Ltd.	March 19, 2007	Canada	-	660,501	-	660,501
Totals				3,276,885		3,276,885

In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

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

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

Executed as to our report referred to above:

(Signed) McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

(Signed) GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

(Signed) Sproule Associates Ltd.
Calgary, Alberta, Canada

APPENDIX C

HARVEST OPERATIONS CORP. AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the board of directors is attached hereto as Appendix "C". The members of the Audit Committee are Dale Blue, Verne Johnson and Hector McFadyen.

Composition of the Audit Committee

The Board of Directors has determined that each member of the Audit Committee is an "independent" director and "financially literate" in accordance with National Instrument 52-110. In considering criteria for the determination of financial literacy, the Board of Directors looked at the ability to read and understand a balance sheet, an income statement and cash flow statement of a public company as well as the director's past experience in reviewing or overseeing the preparation of financial statements.

Relevant Education and Experience

Name (Director Since)	Principal Occupation & Biography
Mr. Dale Blue (February 2006) Other Canadian Public Board of Director Memberships None	Mr. Blue received a Bachelor of Arts degree in economics from the University of Manitoba and has over thirty years experience in the financial services industry and has held senior positions with Chase Manhattan Bank of Canada and Chase Manhattan Bank in New York. He has also served on the Board of Directors of numerous Canadian public companies and various private companies.
Mr. Verne Johnson (December, 2002) Other Canadian Public Board of Director Memberships Fort Chicago Energy Partners, LP Builders Energy Services Trust Suroco Energy Mystique Energy Gran Tierra Energy	Mr. Johnson received a Bachelor of Science degree in in Mechanical Engineering from the University of Manitoba and has accumulated over 35 years of experience in the oil and natural gas industry with multinational majors as well as has served in senior management positions on a number of Alberta based junior and intermediate exploration and production companies. He also serves on several other Boards, including the Boards of other trusts, and on a number of audit committees.
Mr. Hector McFadyen (December, 2002) Other Canadian Public Board of Director Memberships None	Mr. McFadyen has a Masters of Arts degree in economics from the University of Calgary and a Bachelor of Arts degree in economics from Sir George Williams University and has accumulated over 35 years of oil and natural gas industry experience primarily with a senior producer based in Alberta with significant international business interests where he served as a member of the senior management team. He currently serves as a Director of Hunting PLC (a public UK based international oil services company) and privately-held Computershare Trust Company of Canada.

Pre-Approval of Policies and Procedures

All non-audit or special services performed by any independent accountants must be first approved by the Audit Committee. All remuneration provided to the Trust's auditor and any independent accountants are also approved by the Audit Committee. The Trust's auditor meets with the Audit Committee, without management present, at least annually and more often at the request of either the Audit Committee or the auditor.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by the Trust's external auditor in each of the last two fiscal years for audit services (audit and review of Harvest's annual financial statements and review of quarterly financial statements), were $1,080,950 in 2006 and $292,000 in 2005.

Audit and Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance related services by the Trust's external auditor that are reasonably related to the performance of the audit or review of the Trust's financial statements that are not reported under "Audit Fees" above were $66,342 in 2006 and $33,000 in 2005. These fees are primarily related to French translation fees.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Trust's external auditor for regular tax compliance, tax advice and tax planning were $29,800 in 2006 and $69,430 in 2005.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by the Trust's auditors other than services reported above were nil in 2006 and in 2005.

APPENDIX D

HARVEST OPERATIONS CORP. AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Harvest Operations Corp. ("**HOC**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information. The primary objectives of the Committee are as follows:

1. to assist directors to meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Harvest and related matters;

2. to provide better communication between directors and external auditors;

3. to enhance the external auditor's independence;

4. to increase the credibility and objectivity of financial reports; and

5. to strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of HOC, none of whom are members of management of HOC and all of whom are "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("**MI 52-110**") unless the Board shall have determined that the exemption contained in Section 3.6 of MI 52-110 is available and has determined to rely thereon.

2. The Board shall appoint the Committee Chair, who shall be an unrelated director.

3. All of the members of the Committee shall be "financially literate" (as defined in MI 52-110) unless the Board shall determine that an exemption under MI 52-110 from such requirement in respect of any particular member is available and has determined to rely thereon in accordance with the provisions of MI 52-110.

Mandate and Responsibilities of Committee

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

2. It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to Harvest's Internal Control Systems:

    (a) identifying, monitoring and mitigating business risks; and

    (b) ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review the annual and interim financial statements of Harvest and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

(a) reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;

(b) reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

(c) reviewing accounting treatment of unusual or non-recurring transactions;

(d) ascertaining compliance with covenants under loan agreements;

(e) reviewing disclosure requirements for commitments and contingencies;

(f) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

(g) reviewing unresolved differences between management and the external auditors; and

(h) obtain explanations of significant variances with comparative reporting periods.

4. The Committee is to review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Harvest's disclosure of all other financial information and shall periodically assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board, the Committee shall:

(a) recommend to the Board the external auditors to be nominated;

(b) recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;

(c) on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Trust to determine the auditors' independence;

(d) when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

(e) review and pre-approve any non-audit services to be provided to Harvest or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member report to the Committee at the next scheduled meeting such pre–approval and the member comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by Harvest) their assessment of the internal controls of Harvest, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Harvest and its subsidiaries.

7. The Committee shall review risk management policies and procedures of Harvest (i.e. hedging, litigation and insurance).

8. The Committee shall establish a procedure for:

   (a) the receipt, retention and treatment of complaints received by Harvest regarding accounting, internal accounting controls or auditing matters; and

   (b) the confidential, anonymous submission by employees of Harvest of concerns regarding questionable accounting or auditing matters.

9. The Committee shall review and approve Harvest's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Harvest.

10. The Committee shall have the authority to investigate any financial activity of Harvest. All employees of Harvest are to cooperate as requested by the Committee.

11. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of Harvest without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote.

2. The Chair shall preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the members present the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

6. Agendas, approved by the Chair, shall be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Corporation as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

10. Any members of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to

the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of unitholders following appointment as a member of the Committee.

Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board.