U.S. SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 40-F

[ ] REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

[X] ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2007 Commission File Number: **333-121627**

HARVEST ENERGY TRUST

(Exact name of Registrant as specified in its charter)

Alberta, Canada	1311	N/A
(Province or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification No.)*

Suite 2100
330 Fifth Avenue, S.W.
Calgary, Alberta, Canada T2P 0L4
(403) 265-1178
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System
111 Eighth Avenue
New York, New York 10011
(212) 894-8940

Name, address (including zip code) and telephone number (including area codes of agent for service)

Securities registered or to be registered pursuant to Section 12(b) of the Act

Title of Each Class	Name of each exchange on which registered
Trust Units	The New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act

None

For annual reports, indicate by check mark the information filed with this Form:

[X] Annual information form [X] Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

148,291,170 Trust Units

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the filing number assigned to the Registrant in connection with such Rule.

Yes____ No __X__

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes__X__ No ____

FORM 40-F

Principal Documents

The following documents have been filed as part of this annual report on Form 40-F:

(a) Annual Information Form for the fiscal year ended December 31, 2007;

(b) Management's Discussion and Analysis for the fiscal year ended December 31, 2007; and

(c) Consolidated Financial Statements for the fiscal year ended December 31, 2007 *(Note 21 to the Consolidated Financial Statements relates to United States Accounting Principles and Reporting (U.S. GAAP)).*

FORWARD-LOOKING STATEMENTS

This annual report on Form 40-F contains or incorporates by reference forward-looking statements relating to future events or future performance including forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. For a full description of forward-looking information, readers should review the disclosure under the heading “Special Note Regarding Forward Looking Statements” at pages 10 and 11 in the Registrant’s Annual Information Form for the year ended December 31, 2007, which is attached to the annual report on Form 40-F abd is incorporated by reference herein.

HARVEST ENERGY TRUST

ANNUAL INFORMATION FORM

For the year ended December 31, 2007

MARCH 27, 2008

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 Facility**" or "**Three Year Extendible Revolving Credit Facility**" means the credit facility provided by the Current Lenders as more fully described in Note 11 to Harvest's audited consolidated financial statements for the year ended December 31, 2007 filed on www.sedar.com.

"**Current Lenders**" means the syndicate of lenders to Harvest Operations pursuant to the current Credit 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.

"**Downstream**" means our petroleum refining and marketing segment operating under the North Atlantic trade name, comprised of a medium gravity sour crude hydrocracking refinery with a 115,000 bbls/d nameplate capacity and a marketing division with 64 gasoline outlets, a retail heating fuels business and a commercial and wholesale petroleum products business, all located in the Province of Newfoundland and Labrador.

"**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.

"**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.

"**Grand**" means Grand Petroleum Inc, a public 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, 2007".

"**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.

"**HRGP**" means Harvest Refining General Partnership, a general partnership established under the laws of the Province of Alberta, owned 99% by the Trust and 1% by CNG Trust

"**Independent Reserve Engineering Evaluators**" means McDaniel and GLJ, 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, 2007, in accordance with the standards contained in the COGE Handbook and the reserve definitions and other requirements 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, and all wholly owned subsidiaries of North Atlantic, acquired by Harvest on October 19, 2006.

"**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.

"**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, Harvest Reveal Inc. and the Trust (from March 1, 2007) and Harvest Grand Inc. and the Trust (from August 16, 2007) 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 HRGP (and all direct and indirect wholly-owned subsidiaries of HRGP), 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 HRGP (or any direct or indirect wholly-owned subsidiary of HRGP, 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 is described in "Downstream 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 December 31, 2007, by the annualized production of petroleum, natural gas and natural gas liquids from those reserves in 2007.

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

"**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**" or "**SOA**" means the supply and offtake agreement dated October 19, 2006 entered into between North Atlantic and Vitol Refining, S.A., a wholly-owned subsidiary of the vendor to the North Atlantic Acquisition, the terms of which are summarized under the "Downstream 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 Harvest Operations, 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 fourth amended and restated trust indenture dated January 1, 2008 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.

"**Upstream**" means our petroleum and natural gas segment, consisting of the development, production and subsequent sale of petroleum, natural gas and natural gas liquids in Alberta, Saskatchewan and British Columbia.

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

"**VERT**" means Viking Energy Royalty Trust, an open-ended, 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 ABCA 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.

"**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
GJ	gigajoule

Other

AECO	Carlyle/Riverstone Global Energy and Power Fund'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 Annual Information Form 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,		
	2007	2006	2005
High	1.0852	0.9099	0.8690
Low	0.8435	0.8528	0.7872
Period End	1.0088	0.8581	0.8579
Average (1)	0.9418	0.8846	0.8276

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 laws and regulations relating to the oil and natural gas business including without limitation, tax, royalty and environmental law and regulation;
- 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: "Payout Ratio", "Cash G&A", "Operating Netbacks", “Earnings from

Operations” 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 Payout Ratio, Cash G&A and Operating Netbacks as they are non-GAAP measures used extensively in the Canadian energy trust sector for comparative purposes. Payout Ratio is the ratio of distributions to total Cash from Operating Activities. Operating Netbacks are always reported on a per BOE basis, and include gross revenue, royalties, transportation and operating expenses. 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. Earnings from Operations 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, 2007.

STRUCTURE OF HARVEST ENERGY TRUST

Harvest Energy Trust

Harvest Energy 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 effective January 1, 2008. 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 in its Upstream segment as well as conduct petroleum refining and marketing operations in its Downstream segment through its investments. Cash from the Upstream operations 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. Cash flow from the Downstream operations flows to the Trust in the form of interest and principal on unsecured debt owing to the Trust from North Atlantic Refining Limited as well as partnership distributions from Harvest Refining General Partnership.

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. 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, 2002 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 Harvest Exchangeco Ltd. 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." On January 1, 2008, Harvest Operations amalgamated with Harvest Reveal Inc., Harvest Grand Inc. and 1082125 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 Upstream 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 Grand Inc., a taxable corporation

Harvest Grand Inc. (a wholly-owned subsidiary of Harvest Operations incorporated to acquire Grand Petroeum Inc.) amalgamated with Grand Petroleum Inc. on August 16, 2007 and continued as "Harvest Grand Inc." Harvest Grand Inc.'s assets were comprised of the petroleum and natural gas properties from Grand Petroleum Inc. Its operations were limited to the period from July 31, 2007, the date of the acquisition of Grand Petroleum Inc., until the amalgamation of Harvest Grand Inc., Harvest Operations Corp., Harvest Reveal Inc. and 1082125 Alberta Ltd. on January 1, 2008.

Harvest Reveal Inc., a taxable corporation

Harvest Reveal Inc. (a wholly-owned subsidiary of Harvest Operations incorporated to acquire Reveal Resources Ltd.) amalgamated with Reveal Resources Ltd. on March 1, 2007 and continued as "Harvest Reveal Inc." Harvest Reveal Inc.'s assets were comprised of the petroleum and natural gas properties from Reveal Resources Ltd. Its operations were limited to the period from March 1, 2007, the date of the acquisition of Grand Petroleum Inc., until the amalgamation of Harvest Grand Inc., Harvest Operations Corp., Harvest Reveal Inc. and 1082125 Alberta Ltd. on January 1, 2008.

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 Limited 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.

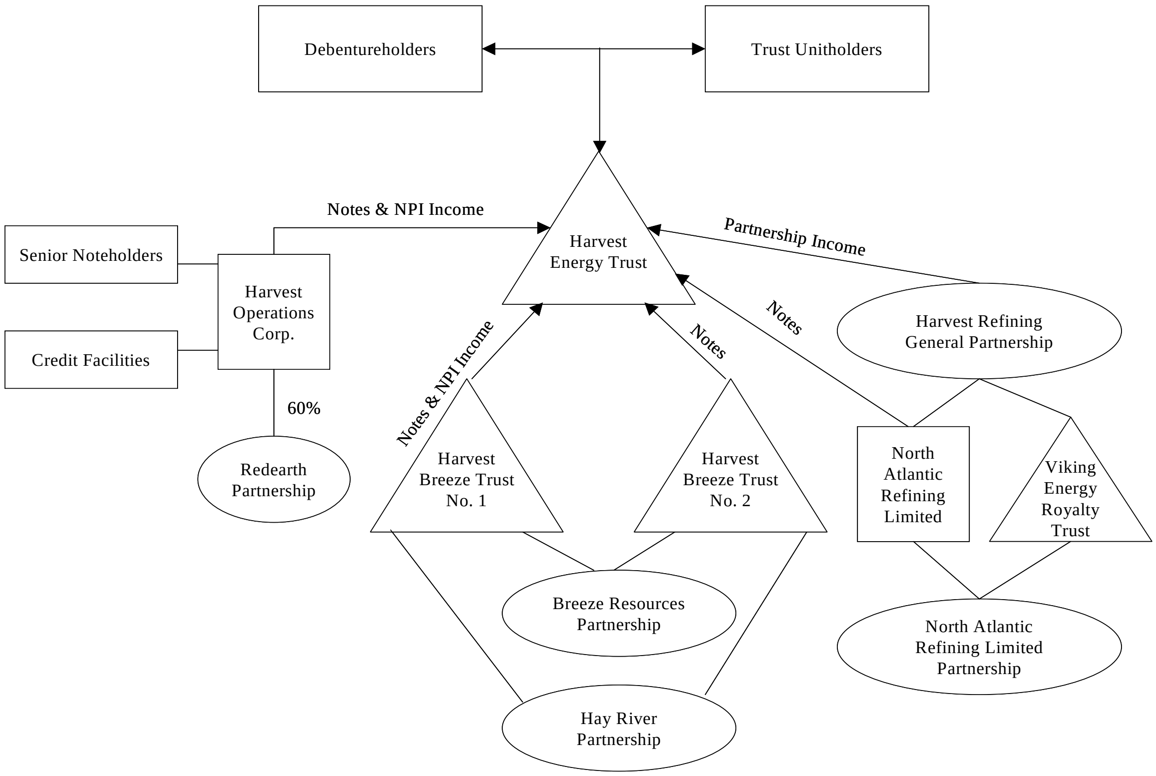
North Atlantic Refining Limited Partnership, a limited partnership

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 and/or interest payments from Harvest Operations, Breeze Trust No. 1, Harvest Breeze Trust No. 2 and North Atlantic Refining Limited and distributions from Harvest Breeze Trust No. 1, Harvest Breeze Trust No. 2, 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 be 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 COGPE account of the Trust, thus creating additional tax deductions in the Trust; 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.

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. for aggregate consideration of approximately $192.2 million. 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 northeastern 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 February 2, 2006, the unitholders of Harvest and of Viking approved a resolution 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. 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.

On July 26, 2006, Harvest entered into an agreement to purchase all of the issued and outstanding shares of Birchill 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.

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 assets of North Atlantic are a 115,000 barrel per stream day sour crude hydrocracking refinery located in the Province of Newfoundland and Labrador and a marketing division with 64 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. The acquisition of North Atlantic created a second business segment for Harvest. Subsequent to purchasing North Atlantic, Harvest had two operating business units: its Upstream operations in western Canada and its Downstream operations in the Province of Newfoundland and Labrador.

During 2006, Harvest's Upstream 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.

Year ended December 31, 2007

On June 11, 2007, Harvest and Grand entered into a pre-agreement whereby Harvest agreed to make an offer to purchase all of the issued and outstanding shares of Grand for $3.84 per share in cash subject to there being at least $66^{2/3}$% of the outstanding shares tendered to the offer. On July 26, 2006, Harvest acquired approximately 74.6% of the outstanding shares of Grand and extended our offer to August 9, 2007, when we acquired an additional 20% of the Grand shares and proceeded to acquire the remaining shares pursuant to the compulsory acquisition provisions of the ABCA. In aggregate, the acquisition cost for Grand totalled $139.3 million comprised of: $109.7 million to acquire the shares of Grand, $28.8 million to repay Grand's bank debt and $0.8 million in respect of related acquisition costs. During the three months ended March 31, 2007, Grand's production averaged 3,409 BOE/d comprised 68% light oil and 32% natural gas. The Grand assets produced as expected contributing approximately 3,350 BOE/d through August and September 2007.

During 2007, Harvest's Upstream production averaged approximately 60,336 BOE/d comprised of approximately 49% light and medium oil, 24% heavy oil and 27% natural gas. Capital spending on internal development in our Upstream business aggregated to $300.7 million, a decrease of $76.2 million over the prior year while capital spending in our Downstream business totalled $44.1 million. For 2007, the daily throughput of feedstock for the Refinery averaged 98,617 bbls/d reflecting two planned shutdowns in the fourth quarter for turnaround and scheduled maintenance activities.

GENERAL BUSINESS DESCRIPTION

Overview

With its acquisition of North Atlantic in October 2006, Harvest became an integrated oil entity with Upstream operations in western Canada and Downstream operations 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 Upstream 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 enhanced oil recovery and other technologies and selective capital investment to maximize reservoir recovery while stressing operational efficiencies to control and reduce operating costs. As at March 20, 2008, Harvest employed 390 full-time employees in its Upstream business, 254 of which are located in the head office and 136 of which are located in the field.

Harvest's Downstream 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. As at March 20, 2008, Harvest employed 560 full-time employees and 140 part-time employees in its Downstream 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 assets with identified operational and development opportunities 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.

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.

Upstream Segment

Within the Upstream segment, Harvest employs the following specific operating strategies:

1. **Acquire Properties with Operational and Development Opportunities** - 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 their net present value.

2. **Enhanced Oil Recovery Projects** - In 2008, Harvest will implement three enhanced oil recovery projects. At Wainwright, we are introducing an alkaline surfactant polymer flood pilot to improve recovery rates. With success of this pilot, we will likely expand it to impact a larger portion of the reservoir at Wainwright. At both Bellshill Lake and Suffield, we are increasing our water reinjections by introducing water produced at adjacent properties to repressurize the reservoir. We have also identified opportunities for similar projects at other fields which may be implemented beyond 2008.

3. **Increase Operating Netbacks** - 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 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.

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 $111.0 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 $111.0 million. Harvest also maintains an industry standard environmental, health and safety program – See "Environmental, Health & Safety Policies & Practices" below under “Other Upstream Information”.

Downstream Segment

Within the Downstream 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.

2. **Profitability Improvement and Expansion –** We have identified numerous near-term profitability enhancement opportunities in our refinery operations including reliability improvements, modest de-bottlenecking of the existing configuration to general cost reduction initiatives which we are pursuing in 2008. In addition, there are larger scale opportunities such as increasing the processing capacity of the Refinery by 33% or more, upgrading our equipment to handle a heavier more sour crude feedstock with a higher refining margin opportunity as well as further processing our existing production of high sulphur fuel oil to a higher value refined product, each of which may cost in excess of $1 billion to engineer and construct. These larger scale opportunities are currently being evaluated as to their technical and economic feasibility by an independent engineering consulting firm.

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.

Cash Flow Risk Management

Harvest employs an integrated approach to cash flow risk management strategies whereby the our cash flow from producing crude oil in western Canada is financially integrated with our requirement to purchase crude oil feedstock for our Downstream operations even though the crude oil produced in western Canada does not physically flow to our refinery in Newfoundland. As a result, our 2008 cash flow at risk is comprised of approximately 38,000 bbls/d of refined product price exposure, 77,000 bbls/d of refined product crack spread exposure and 77,000 Mcf/d of western Canadian natural gas price exposure.

Commencing in 2006, we have limited our financial counterparties to lenders in our syndicated Credit Facility as the security provided under our Credit Facility will extend to our price risk management contracts. This eliminates the requirement for margin calls and the pledging of collateral as well as enables the negotiation of a more limited number of events of default which contributes to limiting the potential that these contracts could exacerbate credit concerns.

During 2007, the net realized loss on price risk management contracts totalled $26.3 million, a $36.3 million reduction from the prior year substantially all related to our crude oil price contracts. For a full description of our price risk management contracts, please refer to Note 18 of our consolidated financial statements for the year ended December 31, 2007 filed on Sedar at www.sedar.com.

UPSTREAM 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, 2008. The effective date of the Statement is December 31, 2007 and the preparation date of the Statement is March 20, 2008.

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, 2007. Harvest's reserves were evaluated by McDaniel (who evaluated approximately 35% of Harvest's total proved plus probable reserves), and GLJ (who evaluated approximately 65% 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, 2008.

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 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 and other requirements 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 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 (Forecast Prices and Costs) – December 31, 2007

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2007
FORECAST PRICES AND COSTS

	RESERVES					
	LIGHT AND MEDIUM OIL(1)		HEAVY OIL(1)		NATURAL GAS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)
PROVED						
Developed Producing	57,967	52,768	34,036	30,803	197,102	162,251
Developed Non-Producing	1,280	1,151	2,104	1,743	19,186	16,094
Undeveloped	6,286	5,533	4,479	3,733	28,724	22,345
TOTAL PROVED	65,532	59,451	40,620	36,279	245,012	200,688
PROBABLE	27,029	24,775	20,073	17,441	96,638	78,042
TOTAL PROVED PLUS PROBABLE	92,561	84,226	60,692	53,720	341,650	278,730

	RESERVES			
	NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (MBOE)	Net (MBOE)
PROVED				
Developed Producing	6,691	5,011	131,545	115,624
Developed Non-Producing	334	236	6,915	5,812
Undeveloped	444	312	15,997	13,303
TOTAL PROVED	7,469	5,560	154,456	134,738
PROBABLE	3,250	2,336	66,458	57,559
TOTAL PROVED PLUS PROBABLE	10,718	7,895	220,914	192,297

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) (2)					Per Boe Discounted
RESERVES CATEGORY	0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)	10% ($/boe)
PROVED						
Developed Producing	3,909,176	3,086,221	2,583,214	2,242,816	1,996,101	19.64
Developed Non-Producing	191,868	138,973	109,999	91,236	77,829	15.91
Undeveloped	349,093	238,634	171,939	128,202	97,693	10.75
TOTAL PROVED	4,450,137	3,463,829	2,865,152	2,462,254	2,171,624	18.55
PROBABLE	2,059,682	1,201,400	809,374	594,346	461,243	12.18
TOTAL PROVED PLUS PROBABLE	6,509,819	4,665,229	3,674,526	3,056,600	2,632,866	16.63

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) (2) 0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
PROVED					
Developed Producing	3,787,413	3,002,074	2,521,828	2,196,317	1,959,868
Developed Non-Producing	171,761	129,858	105,250	88,426	75,978
Undeveloped	300,883	211,631	155,536	117,476	90,261
TOTAL PROVED	4,260,057	3,343,563	2,782,614	2,402,219	2,126,107
PROBABLE	1,588,506	956,789	663,523	499,422	395,631
TOTAL PROVED PLUS PROBABLE	5,848,563	4,300,352	3,446,137	2,901,641	2,521,738

TOTAL

FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($000)	ROYALTIES ($000)	OPERATING COSTS ($000)	DEVELOP-MENT COSTS ($000)	WELL ABANDON-MENT COSTS ($000)	FUTURE NET REVENUE BEFORE INCOME TAXES(2) ($000)	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES(2)
Proved Reserves	9,754,432	1,256,185	3,553,041	325,412	169,658	4,450,136	190,079	4,260,057
Proved Plus Probable Reserves	14,349,689	1,845,011	5,264,233	535,538	195,089	6,509,818	661,255	5,848,563

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000)(2)	UNIT VALUE ($/bbl or $/mcf)
Proved Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	1,130,614	22.99
	Heavy Crude Oil (including solution gas and associated by-products)	1,098,609	21.18
	Associated and Non-Associated Natural Gas (including associated by-products)	634,190	3.45
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	1,454,716	20.21
	Heavy Crude Oil (including solution gas and associated by-products)	1,385,107	18.93
	Associated and Non-Associated Natural Gas (including associated by-products)	832,280	3.22

Notes to Reserves Data Tables

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: 11,952 MMbbl, Proved Undeveloped: 2,839 MMbbl, Total Proved: 14,790 MMbbl, Probable: 3,590 MMbbl and Proved plus Probable: 18,380 MMbbl, and would increase the net heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 10,516 MMbbl, Proved Undeveloped: 2,448 MMbbl, Total Proved: 12,964 MMbbl, Probable: 3,237 MMbbl, and Proved plus Probable: 16,201 MMbbl.

2. 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 Government of Canada has enacted legislation to tax distributions by the Trust commencing January 1, 2011. See "Risk Factors - Risks Related to Harvest's Structure - Changes to the Tax Act

3. Columns may not add due to rounding.

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 those definitions are set forth below.

5. 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.

(b) **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.

(c) **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:

(d) **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.

(e) **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.

(f) **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.

(g) **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, 2008

   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, 2008
FORECAST PRICES AND COSTS

	OIL					NATURAL GAS	NATURAL GAS LIQUIDS	INFLATION RATES [6]	U.S./ CAN EXCHANGE RATE[7]
Year	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] ($Cdn/ bbl)	Alberta AECO Spot Price ($Cdn/ GJ)	Edmonton Cond. and Natural Gasolines ($Cdn/ bbl)	(%/Year)	($US/$Cdn)
Forecast									
2008	90.00	89.00	55.30	64.70	78.20	6.45	91.00	2.0	1.00
2009	86.70	85.70	53.20	62.30	75.30	7.00	87.70	2.0	1.00
2010	83.20	82.20	50.50	59.70	72.20	7.00	84.30	2.0	1.00
2011	79.60	78.50	48.70	57.00	69.00	7.00	80.60	2.0	1.00
2012	78.50	77.40	48.00	56.20	68.00	7.10	79.60	2.0	1.00
2013	77.30	76.20	47.20	55.30	66.90	7.30	78.40	2.0	1.00
2014	78.80	77.70	48.10	56.40	68.20	7.55	80.00	2.0	1.00
2015	80.40	79.30	49.10	57.50	69.60	7.80	81.60	2.0	1.00
2016	82.00	80.80	50.10	58.70	71.00	8.00	83.10	2.0	1.00
2017	83.70	82.50	51.10	59.90	72.50	8.25	84.90	2.0	1.00
2018	85.30	84.10	52.10	61.10	73.80	8.45	86.50	2.0	1.00
2019	87.00	85.80	53.10	62.30	75.30	8.70	88.30	2.0	1.00
2020	88.80	87.50	54.20	63.60	76.90	8.95	90.00	2.0	1.00
2021	90.60	89.30	55.30	64.80	78.40	9.20	91.90	2.0	1.00
2022	92.40	91.10	53.40	66.10	80.00	9.40	93.70	2.0	1.00
There-after	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	1.00

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) Heavy crude oil 12 degrees API at Hardisty Alberta (after deduction of blending costs to reach pipeline quality).
(4) Bow River at Hardisty Alberta (Heavy stream).
(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, 2007, were $6.94/Mcf for natural gas, $62.26/bbl for natural gas liquids, $64.09/bbl for light/medium oil, and $46.71/bbl for heavy oil.

3. 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)	
Year	Proved Reserves	Proved Plus Probable Reserves
2008	$97,283	$180,321
2009	$93,554	$155,311
2010	$41,122	$69,821
2011	$20,274	$37,983
2012	$3,128	$11,767
Thereafter	$70,052	$80,334
Total Undiscounted	$325,412	$535,538
Total Discounted at 10%	$241,027	$416,842

Future development costs will be funded through cash flow and the Trust's Credit Facility.

4. Estimated future abandonment 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. No allowance was made, however, for reclamation of wellsites or the abandonment and reclamation of any facilities. See “Other Upstream Business Information – Additional Information Concerning Abandonment and Reclamation Costs” for more information.

5. The forecast price and cost assumptions assume the continuance of current laws and regulations.

6. 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

RECONCILIATION OF
OPERATING SUBSIDIARIES COMPANY GROSS
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

FACTORS	LIGHT AND MEDIUM OIL Gross Proved (Mbbl)	LIGHT AND MEDIUM OIL Gross Probable (Mbbl)	LIGHT AND MEDIUM OIL Gross Proved Plus Probable (Mbbl)	HEAVY OIL Gross Proved (Mbbl)	HEAVY OIL Gross Probable (Mbbl)	HEAVY OIL Gross Proved Plus Probable (Mbbl)	ASSOCIATED AND NON-ASSOCIATED NATURAL GAS Gross Proved (MMcf)	ASSOCIATED AND NON-ASSOCIATED NATURAL GAS Gross Probable (MMcf)	ASSOCIATED AND NON-ASSOCIATED NATURAL GAS Gross Proved Plus Probable (MMcf)
December 31, 2006	68,135	23,230	91,365	39,515	16,725	56,240	258,636	104,913	363,550
Extensions/ Improved Recovery	4,191	5,181	9,372	1,734	3,169	4,903	13,818	12,296	26,114
Technical Revisions	1,801	(2,312)	(511)	1,275	(2,192)	(917)	(1,381)	(25,337)	(26,717)
Discoveries	15	5	20				1,242	730	1,972
Acquisitions	1,683	1,135	2,818	3,319	2,3686	5,687	11,239	5,531	16,770
Dispositions	(510)	(252)	(762)				(3,056)	(1,482)	(4,538)
Economic Factors	132	42	174	58	3	61	190	13	177
Production	(9,915)		(9,915)	(5,281)		(5,281)	(35,677)		(35,677)
December 31, 2007	65,532	27,029	92,561	40,620	20,073	60,692	245,012	96,638	341,650

FACTORS	NATURAL GAS LIQUIDS Gross Proved (Mbbl)	NATURAL GAS LIQUIDS Gross Probable (Mbbl)	NATURAL GAS LIQUIDS Gross Proved Plus Probable (Mbbl)	TOTAL (BOE) Gross Proved (MBOE)	TOTAL (BOE) Gross Probable (MBOE)	TOTAL (BOE) Gross Proved Plus Probable (MBOE)
December 31, 2006	8,171	3,572	11,743	158,927	61,013	219,940
Extensions/ Improved Recovery	331	540	871	8,559	10,939	19,497
Technical Revisions	(543)	(1,037)	(1,579)	2,303	(9,764)	(7,460)
Discoveries	51	37	88	273	164	437
Acquisitions	369	152	521	7,244	4,577	11,821
Dispositions	(36)	(15)	(51)	(1,055)	(514)	(1,569)
Economic Factors	6		6	228	43	271
Production	(880)		(880)	(22,023)		(22,023)
December 31, 2007	7,469	3,250	10,718	154,456	66,458	220,914

Note:
(1) Columns may not add due to rounding.

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, 2008, Harvest has a total of 22.9 MMBOE of company interest reserves that are classified as proved non-producing. Of these non-producing reserves approximately 70% 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 2008 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 are expected 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.

TIMING OF INITIAL UNDEVELOPED
RESERVES ASSIGNMENT

	Company Gross Reserves First Attributed by Year					
PRODUCT TYPE	Units	Prior	2005	2006	2007	Total
Proved Undeveloped						
Light and Medium Crude Oil	Mbbl	686	10	925	1,826	3,447
Heavy Crude Oil	Mbbl	600	0	1,428	5,290	7,318
Natural Gas	MMcf	65	0	6,164	22,494	28,723
Natural Gas Liquids	Mbbl	23	0	219	202	444
Total Oil Equivalent	MBOE	1,320	10	3,599	11,067	15,996
Proved Plus Probable						
Light and Medium Crude Oil	Mbbl	1,046	3	844	7,837	9,730
Heavy Crude Oil	Mbbl	3,048	0	1,185	5,802	10,035
Natural Gas	MMcf	740	0	4,328	21,972	27,039
Natural Gas Liquids	Mbbl	60	0	155	775	990
Total Oil Equivalent	MBOE	4,277	3	2,906	18,076	25,262

Notes: Hay River Reserves are included in Heavy for this analysis

First attributed volumes include additions during the year and do not include revisions to previous undeveloped reserves.

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, 2008.

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 Wells

The following table sets forth the number of wells in which Harvest held a working interest as at December 31, 2007:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	3,121	2,548.9	1,027	846.9	1,635	712.5	462	253.1
British Columbia	155	155.0	46	44.6	0	0.0	23	8.2
Saskatchewan	1,172	980.9	384	353.8	10	10.0	40	38.6
Total	4,448	3,684.8	1,457	1,245.3	1,645	722.5	525	299.9

	Service Wells			
	Active		Suspended	
	Gross	Net	Gross	Net
Alberta	557	476.8	67	52.2
British Columbia	122	122.0	4	4.0
Saskatchewan	188	161.3	11	9.6
Total	867	760.1	82	65.8

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 2007 financial year:

	Exploratory Wells		Development Wells	
	Gross[(1)]	Net[(1)]	Gross[(1)]	Net[(1)]
Oil Wells	0	0	107	97.2
Gas Wells	4	2.5	62	24.2
Service Wells	0	0	5	5.0
Dry Holes	0	0	4	2.6
Total Wells	4	2.5	178	129.0

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 "2008 Capital Expenditures Plan" section under “Other Upstream Information”.

Properties with No Attributed Reserves

The following table sets out Harvest's undeveloped land holdings as at December 31, 2007.

	Undeveloped Acres	
	Gross	Net
Alberta	612,170	410,293
British Columbia	46,382	36,639
Saskatchewan	150,132	134,587
Total	808,683	581,520

	Undeveloped Acres for which rights expire within one year	
	Gross	Net
Alberta	96,889	77,183
British Columbia	4,958	2,479
Saskatchewan	53,732	50,088
Total	155,579	129,750

Production Estimates

The following table sets forth the volume of company working interest production estimated for 2008 as found in the reserve reports:

	2008 Production Forecast				
	Light and Medium Oil (bblsd)	Heavy Oil (bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Total (BOE/d)
Proved Producing	21,225	15,487	94,801	2,805	55,317
Proved Developed Non-Producing	266	345	6,602	98	1,810
Proved Undeveloped	674	1,218	3,831	66	2,596
Total Proved	22,165	17,050	105,234	2,969	59,723
Total Probable	1,400	1,867	9,597	268	5,135
Total Proved Plus Probable	23,566	18,917	114,831	3,237	64,858

OTHER UPSTREAM BUSINESS INFORMATION

Oil and Natural Gas Properties

The Operating Subsidiaries' portfolio of significant Properties is discussed below. Reserve amounts discussed are gross reserves and are stated at December 31, 2007 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 Harvest Operations.

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 Harvest Operations is actively engaged in cost reduction, production and reserve replacement optimization efforts directed at reserve addition through extending the economic life of these producing properties beyond the limits used in the Reserve Report and developing new proven reserves previously not evaluated by the Independent Reserve Engineering Evaluators. In respect of the Properties, the Harvest Operations has entered into a number of electrical power swaps to manage a portion of the risk associated with electrical power cost volatility, which is a significant portion of the production costs associated with the Properties.

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.

2007 Historical Production by Material Property

Material Property	Light, Medium and Heavy Crude Oil (bbls/d)	Natural gas (Mcf/d)	NGL (bbls/d)	Average Daily Production (BOE/d)
SE Saskatchewan	5,727	294	98	5,874
Markerville / Sylvan Lake	690	25,767	779	5,764
Hay River	5,410	0	0	5,410
Suffield	5,202	631	25	5,332
Hayter	3,038	314	12	3,102
Red Earth	2,725	307	76	2,852
Wainwright/Viking Kinsella	2,752	106	3	2,773
Rimbey	241	11,028	576	2,655
Bellshill Lake	2,070	1,410	56	2,361
Crossfield	46	6,422	313	1,429
Lloydminster	1,123	162	0	1,150
Bashaw	899	888	70	1,117
Kindersley	943	579	33	1,073
Other	10,768	49,837	371	19,445
Total	41,634	97,744	2,412	60,337

Principal Producing Properties at December 31, 2007

<u>SE Saskatchewan</u>*:* Our SE Saskatchewan properties are located approximately 110 miles southeast of Regina. Production from SE Saskatchewan averaged 5,874 BOE/d of average 33° API crude oil in 2007, primarily produced from the Tilston and Souris Valley Formations. The SE Saskatchewan property includes Hazelwood, Moose Valley, Parkman, Whitebear, Kenosee and other minor properties. Harvest has an average working interest of over 90% in this primarily operated property. Through the acquisition of Grand in August 2007, Harvest acquired a 50% working interest in approximately 25,000 undeveloped acres (12,500 net to Harvest) and 600 BOE/d of production (300 net to Harvest). This acreage was directly offsetting Harvest's Hazelwood horizontal well development program and has provided incremental drilling opportunities. In 2007 Harvest drilled 33 gross (29 net) wells, primarily horizontal development and infill wells into defined pools including 14 horizontal wells into our Kenosee pool discovered in 2006. In 2007, total capital expenditures were approximately $40 million including $3 million to install emulsion processing facilities at our new Kenosee Souris Valley pool. Fluid produced from the area is processed at our 100% owned Hazelwood facility and is pipeline connected to the Enbridge system. Additional future development at SE Saskatchewan may include step-out and horizontal infill drilling of up to 100 locations to increase the recovery factor and accelerate production. Harvest believes further drilling opportunities are possible through the continued pooling of other landowner interests to drill under-exploited areas. Harvest has extensive proprietary 3D seismic coverage which offers control of the opportunity, and will be used to identify further opportunities on and off our land base.

<u>Markerville</u>*:* The Markerville 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 5,764 BOE/d (75% natural gas) for the 12 months ending December 31, 2007. The area offers multi-zone potential with a number of 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 located at a depth of approximately 800m that contains sweet natural gas that is developed exclusively with vertical wells. Harvest also has a 25-50% working interest in Leduc Pinnacle Reef formations that produce light oil and associated natural gas. In 2007, the company drilled or participated in 22 gross (9.6 net) wells for a total capital expenditure of $13 million in the area. Also in August 2007, Harvest acquired the assets of Grand which included approximately 1,600 BOE/d of natural gas and associated liquids producing from the Ellerslie, Pekisko and Elkton formations. Drilling success on these lands included the discovery of a new Ellerslie Gas pool into which Harvest has drilled 2 wells by the end of 2007. Harvest has various ownership in pipelines, compressors, and gas processing facilities that service the wells in this area.

Hay River*:* Hay River was acquired by Harvest on August 2, 2005 and is located approximately 125 miles NE of Grande Prairie in northeastern British Columbia. In 2007 Hay River produced 5,410 BOE/d of medium gravity (24° API) crude oil which was processed at our central emulsion processing facility with the clean oil transported via pipeline to sales points. Hay River is a winter only access area in that drilling operations can only be undertaken when the ground is frozen (typically between late December and late March) The Hay River medium gravity oil production is priced at a discount to the Edmonton Light oil benchmark, contributing to stronger netbacks when compared to other similar gravity crudes . Harvest has an average 100% working interest in this operated property. In the first quarter of 2007, we drilled 31 gross (31 net) wells for a net expenditure of $40 million. This was a continuation of the winter drilling program that was initiated in December 2006 when an additional 4 wells were drilled (total of 35 for the winter season). 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 completed construction of an all season access road to improve access to the area, the installation of a gas plant to allow for re-injection or sale of natural gas that is currently flared thus reducing greenhouse gas emissions, and the connection to commercial power through BC Hydro which will improve overall electrical efficiency.

Suffield*:* Suffield is located 160 miles SE of Calgary and is located on the site of the Canadian Forces Base Suffield. Production from this region averaged 5,332 BOE/d of primarily heavy oil in 2007, averaging 11-18° API from the Upper Mannville Glauconitic formation. Harvest has an average 99% working interest in this operated property. Fluid produced from the area is processed at three emulsion processing facilities located at Caen, Lark and Batus with clean oil transported via pipeline to sales points. In 2007 Harvest invested $17 million to drill 11 gross (11 net) wells to optimize our producing infrastructure in the region. Future development at Suffield may include step-out, extension and infill drilling at up to 45 identified locations. Pool optimization and enhanced recovery projects will target increased water injection into under-injected reservoirs that have not received adequate pressure maintenance. Specifically for 2007, produced water from our main Batus field will be re-injected into our Lark field to increase reservoir pressure and ultimate oil recovery from this field.

Hayter*:* Harvest acquired the Hayter property in November 2002. Production in 2007 at Hayter averaged approximately 3,100 BOE/d of 14° to 15° API oil, producing from the Lower Cretaceous Cummings/Dina formation. Harvest has an average 94% working interest in this operated property. Emulsion produced from the wells is processed at one of two central processing facilities and then transported via pipeline to sales points. In 2007, Harvest drilled 7 gross (5.3 net) horizontal wells for a total expenditure of $5 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. Harvest has identified the Hayter area as being amenable for enhanced recovery. A condensate injection pilot commenced in 2006, as well as an acid gas injection pilot in 2007. We will continue to test these potential enhanced recovery technologies through 2008 with the intent of commissioning a pilot in 2009. Operating expense reduction projects such as low pressure water disposal wells, horizontal disposal wells, and battery optimization are ongoing.

Red Earth*:* Production in 2007 from Red Earth averaged 2,852 BOE/d of oil (98% oil) averaging 37° to 39° API from the Devonian Slave Point, Granite Wash and Gilwood 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 2007, Harvest drilled 12 gross (8.5 net) wells for a total expenditure of $15 million. In addition, Harvest acquired approximately 11,000 net acres of undeveloped oil sands rights to complement the oil sands rights acquired in 2006 and which is adjacent to our existing light oil production and pipeline infrastructure. Harvest also expanded the capacity of our EVI 3 emulsion processing facility for a total expenditure of $8 million to accommodate increased fluid production from existing wells as wells as future opportunities. Future development at Red Earth may include downspace drilling in the Slave Point G pool, as well as potential water injection to increase the recovery factor in a number of smaller Slave point pools by offsetting 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.

Wainwright: Harvest acquired the Wainwright properties in September, 2004. Production in 2007 from these pools averaged approximately 2,773 BOE/d of 22° to 24° API oil, produced from the Cretaceous Upper Mannville Sparky Formation. Harvest has an average 99% working interest in these operated properties. In 2007, an engineering firm completed a study to evaluate the feasibility of using a polymer based injection fluid to increase waterflood sweep efficiencies and ultimate recoveries in this large oil pool. The results of this study indicate the reservoir is amenable to Alkaline Surfactant Polymer injection, with the potential to increase overall recovery from this field by 10-15%.

Rimbey: The Rimbey area includes producing assets at Ferrier, Wilson Creek, Willesden Green and Rose Creek., and is located approximately 50 miles NW of Red Deer. In 2007 the Rimbey area produced 2,665 BOE/d of primarily natural gas (approximately 70%) from various formations including the Rock Creek, Viking, Ostracod, and Cardium . Harvest's working interest in this area ranges from 25% to 100%. In 2007 Harvest drilled 8 gross (4.9 net) wells for a total net expenditure of $18 million. In addition, to the drilling, harvest participated in the construction at a gas processing facility at South Ferrier for a net capital cost of $3 million. Gas produced from this area is generally transported on company owned and third party owned infrastructure to five company owned compression facilities at Wilson Creek and Rose Creek, Willesden Green and Ferrier as well as third party gas processing facilities.

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° to 28° API oil produced from the Ellerslie, and Dina formations, and totaled 2,361 BOE/d in 2007 weighted 90% 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 2007 Harvest commissioned an engineering study to assess improved recovery opportunities, primarily in the unit. The results of this study indicate incremental oil recovery can be achieved with increased water injection, which Harvest will pursue in 2008.

Crossfield: Crossfield is located approximately 20 miles NW of Calgary. Production in 2007 from this region was primarily natural gas (75%) with some liquids and averaged approximately 1,429 BOE/d from the Lower Cretaceous Basal Quartz formation. Harvest has an average 75% working interest in this operated and non-operated property. In 2007, the operator of the Balzac gas plant that processes gas from Harevst's wells shut down the plant for an extended turnaround which impacted volumes for the year by approximately 340 BOE/d. Harvest has a 1% working interest in the Balzac gas plant, and was also impacted by increased operating costs during the turnaround. Through a farm-out arrangement with a junior oil and gas producer, Harvest participated in 8 gross (0.8 net) wells in Crossfield for a total capital expenditure of $2 million. Harvest continues to evaluate opportunities to downspace and drill additional locations at Crossfield.

Lloydminster: Harvest has a 100% working interest in this heavy oil field located 10 miles south of the town of Lloydminster. Production of 12-14 API heavy crude oil is from the Lloydminster sandstone formation, and averaged 1,150 BOE/d (98% oil) in 2007. Harvest drilled 15 gross (15 net) horizontal wells in 2007 for a net expenditure of $16 million. Production from the area wells is processed in single well batteries and then trucked to Harvest's Bellshill Lake pipeline terminal sales point. Future plans include downspacing the pool with additional horizontal wells and assessing the potential impact of water injection for pressure maintenance and enhanced recovery.

Bashaw: Harvest has a 93.3% working interest in the operated Bashaw D2G pool, and a 90.6% working interest in the operated Bashaw D2L pool. This area produces oil and gas from the Nisku/Leduc reef formation at an average depth of 1,700m. Average production for 2007 was 1,117 BOE/d with 84% weighted to oil and liquids on a BOE basis. In 2007, Harvest drilled 2 gross (1.9 net) wells for a total expenditure of $2.4 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 as optimization of the existing waterflood patterns to improve recovery factors. Bashaw has been identified as amenable to miscible CO_2 injection which would improve ultimate oil ecovery from this field should a suitable CO_2 source and transportation infrastructure be established.

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 2007 averaged 1,073 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 utilizing saturated brine to improve oil sweep efficiency and ultimate recovery factors from this reservoir targeted for 2009.

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, 2007:

Property costs	($millions)
Proved properties	135.1
Undeveloped properties	3.0
Total costs	138.1
Exploration costs	3.1
Development costs	297.6
Total Capital Expenditures	438.8

2008 Capital Expenditure Plan

Harvest’s expected total capital spending on its oil and natural gas properties for 2008 is expected to be approximately $225 million. The primary areas of focus for Harvest’s capital program during 2008 are the following:

SE Saskatchewan – drill approximately 40 gross (40 net) light oil wells for a net expenditure of $45 million.

Markerville – drill 23 gross (11 net) gas wells for a net expenditure of $12 million.

Suffield – drill 14 gross (14 net) heavy oil wells for a net expenditure of $11 million including a number of horizontal re-entry wells that will access incremental oil from existing wellbores. An incremental $2 million is allocated for increased water injection into the Lark field to improve recovery factors.

Red Earth – drill 11 gross (10 net) light oilwells for a net expenditure of $16 million.

Lloydminster / Hayter – drill 21 gross (19 net) heavy oil horizontal wells for a net expenditure of $16 million.

Ferrier – drill 6 gross (3 net) gas wells for a net expenditure of $11 million.

Wainwright – install pilot infrastructure for Alkaline Surfactant Polymer flood for a net expenditure of $7 million.

Bellshill Lake – Install pipeline infrastructure to increase water injection into Bellshill Lake Ellerslie pool for a net expenditure of $3 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:

- Implementation or optimization of enhanced waterfloods in selected pools such as Hay River and Kindersley resulting in increased production and recovery;
- Increasing water handling and water disposal capacity at key fields such as Hayter, Suffield and Bellshill Lake to add incremental oil volumes. This includes additional use of free water knock-outs and additional disposal wells;
- De-bottlenecking existing fluid handling facilities and surface infrastructure;
- 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;
- Uphole completions of bypassed or untested reserves in existing wellbores, including recompletion of existing shut-in wells to access undrained reserves;
- Selected infill and step-out development drilling opportunities for various proven targets generally defined by 3D seismic;
- Numerous exploratory opportunities defined by seismic from which value might be extracted by sale, farmout or joint venture.
- Opportunity to increase recovery factors in established pools using available and evolving enhanced recovery technolgies such as ASP at Wainwright, CO2 injection at Bashaw and acid gas injection at Hayter.

Marketing Arrangements

Crude Oil and Natural Gas Liquids (NGLs')

Harvest's crude oil and NGL production is marketed to a diverse portfolio of intermediaries and end users with contracts on 30 day continuously renewing basis and the NGL contracts on one year terms with both commodities receiving the prevailing monthly market prices. Harvest has a small number of condensate purchase contracts, required for blending heavy oil to meet pipeline specifications, that are a combination of one year and monthly spot contracts both at the prevailing monthly price.

Harvest received an average sales price, excluding the effects of commodity price risk management contracts, of $64.09/bbl for its light and medium crude oil, $46.71/bbl for its heavy crude oil and $62.26/bbl for its NLG’s for the year ending December 31, 2007 compared to $59.82/bbl, $46.14/bbl and $58.54/bbl for the year ending December 31, 2006, respectively.

Natural Gas

Approximately 93% of Harvest's natural gas production is currently being sold at the prevailing daily spot market price in Alberta with the remaining 7% of its production dedicated to aggregator contracts which are contracted for the economic life of the reserves.

Harvest received an average sales price, excluding the effects of commodity price risk contracts, of $6.94/Mcf for its natural gas for the year ending December 31, 2007 compared to $6.76/Mcf in 2006.

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, 2007	869,455	159,100
Anticipated to be paid in 2008	20,400	18,546
Anticipated to be paid in 2009	7,546	6,236
Anticipated to be paid in 2010	7,838	5,889

The number of net wells for which the Independent Reserve Engineering Evaluators estimated that Harvest would incur abandonment and reclamation costs is 4,680 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 $712.0 million ($112.5 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.

Production History

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

Average Daily Production Volumes (before the deduction of royalties)	2007				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil (bbls/d) (1)	27,034	27,586	27,401	26,640	27,165
Heavy Oil (bbls/d)	15,614	14,719	14,217	13,354	14,469
Total Oil (bbls/d)	42,648	42,305	41,618	39,994	41,634
NGL (bbls/d)	2,496	2,338	2,219	2,595	2,412
Natural Gas(Mcf/d)	101,282	98,078	96,737	94,961	97,744
Total Daily Production (BOE/d)	62,024	60,989	59,961	58,416	60,336

Total Sales Production	2007				
	Q1	Q2	Q3	Q4	Total
Light and Medium Oil (bbls) (1)	2,433,077	2,510,343	2,520,909	2,450,896	9,915,225
Heavy Oil (bbls)	1,405,251	1,339,420	1,307,955	1,228,559	5,281,185
Total Oil (bbls)	3,838,328	3,849,763	3,828,864	3,679,455	15,196,410
NGL (bbls)	224,664	212,782	204,171	238,763	880,380
Natural Gas (Mcf)	9,115,346	8,925,064	8,899,771	8,736,379	35,676,560
Total Production (BOE)	5,582,216	5,550,056	5,516,330	5,374,281	22,022,883

Average Sales Prices Received

	2007				
	Q1	Q2	Q3	Q4	Total
Light & Medium oil ($/bbl) [(1)]	$ 58.90	$ 59.20	$ 68.10	$ 70.97	$ 64.09
Heavy Oil ($/bbl)	44.54	43.27	48.95	48.87	46.71
Total Oil ($/bbl)	53.64	53.66	61.56	63.59	58.05
Natural Gas ($/Mcf)	8.05	7.57	5.67	6.43	6.94
NGL ($/bbl)	52.78	58.67	61.63	74.92	62.26
Total BOE ($/BOE)	$ 52.15	$ 51.64	$ 54.15	$ 57.32	$ 53.78

Royalties Paid

	2007				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($000) [(1)]	$ 23,250	$ 28,517	$ 33,996	$ 30,425	$ 116,188
Heavy Oil ($000)	11,386	10,044	10,460	9,879	41,769
Natural gas & NGL's ($000)	15,013	14,987	12,350	13,106	55,456
Total BOE ($000)	$ 49,649	$ 53,548	$ 56,806	$ 53,410	$ 213,413
Light & Medium Oil ($/bbl) [(1)]	$ 9.56	$ 11.36	$ 13.49	$ 12.41	$ 11.72
Heavy Oil ($/bbl)	8.10	7.50	8.00	8.04	7.91
Natural gas & NGL's ($/BOE)	8.61	8.81	7.32	7.73	8.12
Total BOE ($/BOE)	$ 8.89	$ 9.65	$ 10.30	$ 9.94	$ 9.69

Operating Expenses[(2)]

	2007				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($000) [(1)]	$ 35,500	$ 35,060	$ 38,508	$ 38,049	$ 147,117
Heavy Oil ($000)	18,316	18,106	17,105	17,465	70,992
Natural gas & NGL's ($000)	18,480	19,167	24,576	20,586	82,809
Total BOE ($000)	$ 72,296	$ 72,333	$ 80,189	$ 76,100	$ 300,918
Light & Medium Oil ($/bbl) [(1)]	$14.59	$ 13.97	$ 15.28	$ 15.52	$ 14.84
Heavy Oil ($/bbl)	13.03	13.52	13.08	14.22	13.44
Natural gas & NGL's ($/BOE)	10.60	11.27	14.56	12.15	12.13
Total BOE ($/BOE)	$ 12.95	$ 13.03	$ 14.54	$ 14.16	$ 13.66

Netback Received[(2)]

	2007				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($/bbl) [(1)]	$ 34.75	$ 33.87	$ 39.33	$ 43.04	$ 37.53
Heavy Oil ($/bbl)	23.41	22.25	27.87	26.61	25.36
Natural gas & NGL's ($/BOE)	29.67	27.00	15.48	23.80	24.05
Total BOE ($/BOE)	$ 30.31	$ 28.96	$ 29.31	$ 33.22	$ 30.43

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) Before gains or losses on commodity derivatives.

Potential Acquisitions

Harvest 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. Harvest 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, Harvest has not reached agreement on the price or terms of any potential material acquisitions and cannot predict whether any current or future opportunities will result in one or more acquisitions for Harvest.

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. Prior to 2011, these distributions will not be subject to tax at the Trust level. If Harvest maintains its existing structure after 2010, its distributions will be taxed at rates of 29.5% in 2011 and 28% in subsequent years. See "Risk Factors – Risks Related to Harvest's Structure – Changes to the Tax Act".

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 2007, Harvest invested $13.1 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 2007, 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, 2007 and under the heading "Risk Management Contracts" in Harvest's management discussion and analysis for the year ended December 31, 2007 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, 2007 and the "Risk Management Financing and Other" discussion in Harvest's management discussion and analysis for the year ended December 31, 2007 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

Prior to 2009:
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.
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.

Subsequent to 2008:
On October 25, 2007, the Government of Alberta released its New Royalty Framework outlining changes that effective January 1, 2009 will increase the royalty rates on conventional oil and gas, oil sands and coalbed methane using a price-sensitive and volume-sensitive sliding rate formula for both conventional oil and natural gas. While there are considerable details to be provided, our preliminary assessment is that the impact of the changes on Harvest will be modest at current prices, as many of our oil and natural gas wells will be considered low productivity wells that continue to attract favourable royalty treatment. Based on the information available and assuming royalties will continue to be based on field gate prices realized by producers, our analysis indicates that if our field gate prices are less than $53.00, our oil royalties will be lower and if prices are higher, our royalties will increase and similarly for natural gas, if our gas plant prices are less than $7.00, our royalties will be lower and if prices are higher, our royalties will increase. Of particular concern is the royalty rates on natural gas where production from recently drilled wells may qualify as high productivity for a period of time and attract a royalty that is 15% to 20% higher than under the current royalty regime and this could significantly penalize the economics of our drilling natural gas wells. Generally, we will pay higher royalties if commodity prices are high and lower royalties on most of our wells as they will be considered to be low productivity wells.

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 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 oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation 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 "**EPEA**"), which came into force on September 1, 1993, and the Oil and Gas Conservation Act (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the Climate Change and Emissions Management Amendment Act came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. The Corporation will be 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 EPEA and similar legislation in other jurisdictions in which it operates. The Corporation believes that it is in material compliance with applicable environmental laws and regulations. The Corporation also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for in situ oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating CO_2 from other emissions supporting carbon capture and storage.

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. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and gas sector. Among the changes to be implemented are: (i) a new Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) the new Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, on February 19, 2008 the provincial Government announced that starting on July 1, 2008, provided the legislation is approved; a revenue-neutral carbon tax will be applied to all fossil fuels used in the Province. The tax would be phased in, and the initial rate would be based on CO_2e of $10 per tonne for the first six months of 2009 and $15 per tonne for the last six months of 2009, following $5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government would receive otherwise.

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. It is questionable, based on the Updated Action Plan announced by the federal government (see below), that the Kyoto target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oils sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and in-situ production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO2 equivalent per upstream oil and gas facilities; and (iii) 10,000 BOE/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either cancel the offset credits or bank them for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

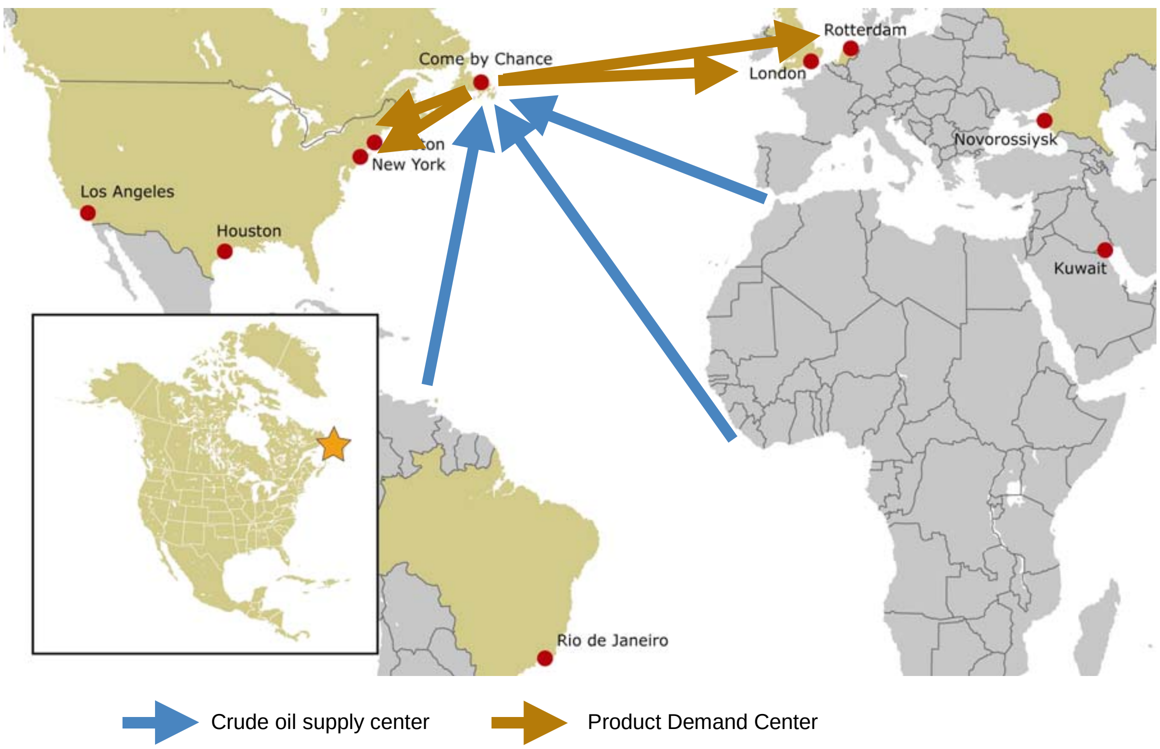
Finally, a one-time credit of up to 15 Mt worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition at this time.

DOWNSTREAM BUSINESS

Harvest’s Downstream business operating under the North Atlantic trade name is comprised of a medium gravity sour crude hydrocracking refinery with a 115,000 bbls/d nameplate capacity and a marketing division with 64 gasoline outlets, a retail heating fuels business and a commercial and wholesale petroleum products business, all located in the Province of Newfoundland and Labrador. The sales volume of our marketing division represents approximately 20% of the Newfoundland market.

The Refinery's feedstocks are delivered by tanker primarily from Iraq, Russia and Venezuela. The Refinery produces high quality gasoline, ultra low sulphur diesel, jet fuel and furnace oil with a residual of high sulphur fuel oil. Approximately 10% of our 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, or further abroad if economics warrant the increased shipping charges. The Refinery 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 this 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

Harvest's Downstream assets include dock facilities for off-loading crude oil feedstock and for loading refined products. The dock facilities handle approximately 220 vessels each year with Harvest 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, Harvest operates a petroleum marketing and distribution business in the Province of Newfoundland and Labrador with average daily sales over 14,000 barrels.

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 unit. 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 prior to our acquisition of the Refinery in late 2006. These investments significantly improved the Refinery's operating performance in terms of refinery throughput, reliability, saleable yield, product quality, safety and environmental performance. In 2007, the Refinery averaged 98,617 barrels per stream day, up slightly from 94,800 barrels per stream day in the prior year. Both production years were impacted by planned maintenance turnarounds, with a saleable yield of 99.4% in 2007 and 95.1% in 2006 while its safety performance was nil lost time accidents per 200,000 man hours in 2007 and 0.84 lost time accidents per 200,000 man hours in 2006. Since 1997, the Refinery's sulphur dioxide emissions have also been reduced by 63% despite a significant increase in throughput.

Refinery Operations

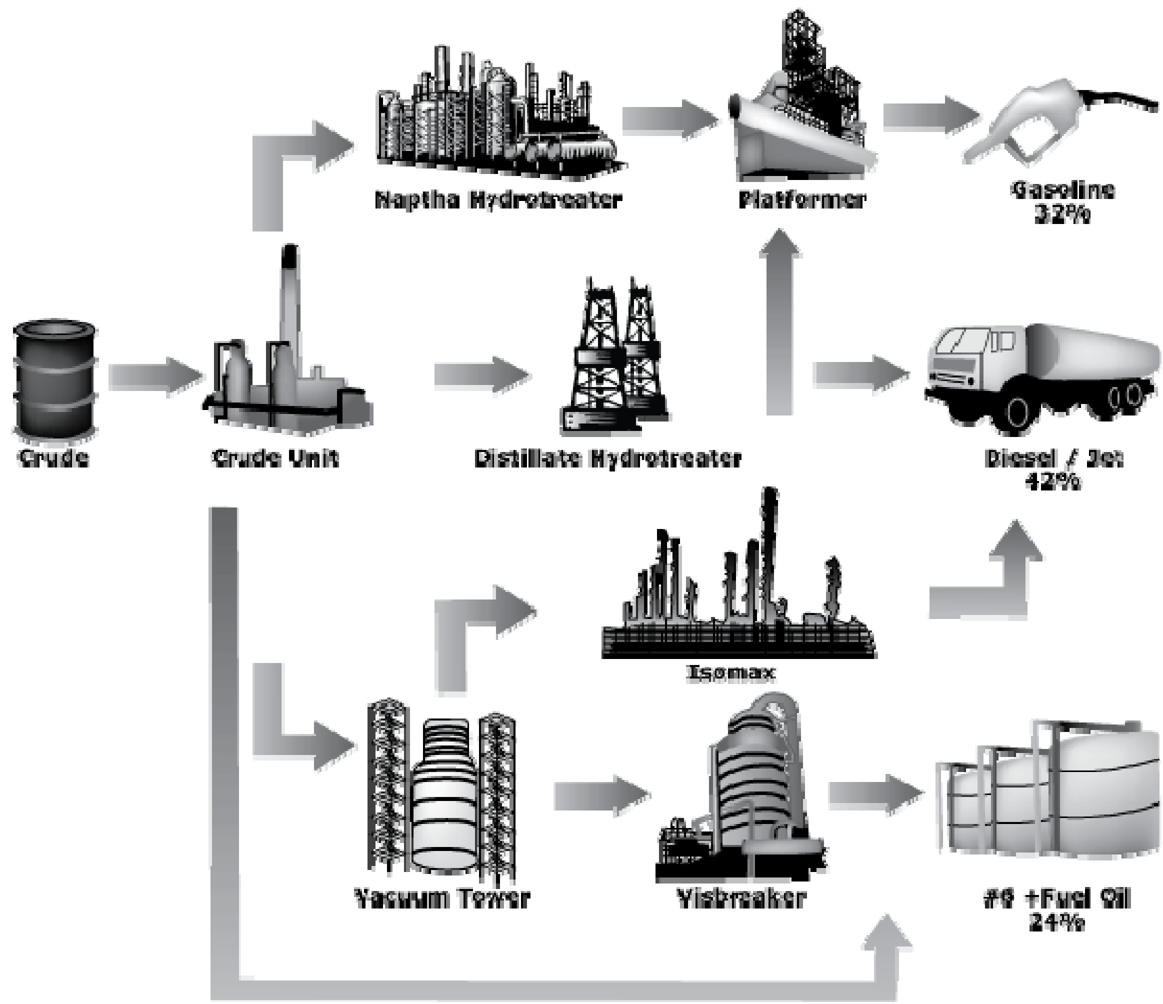
Summary of Refinery Inputs

Crude oil and other feedstocks are delivered to the Refinery via vessels capable of carrying over 2 million barrels of crude oil. Normally, there are 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:

	2007	2006	2005
	(Mbbls)	(Mbbls)	(Mbbls)
Basrah Light	23,230	25,535	23,672
Hamaca	5,180	4,258	2,686
Urals	3,367	1,148	5,596
Other	4,218	3,667	2,324
Total Feedstock	**35,995**	**34,608**	**34,278**

Overview of Crude Oil Processing

The following is a summary of the primary process flow of the 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 Units

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

- Non-condensable petroleum gases that are combusted as fuel within the Refinery processes;
- Liquid petroleum gas products such as propane and butane, that are included among finished product sales volumes;
- Light liquid products (naphtha) which are further upgraded in the naphtha hydrotreater and platformer for the production of gasoline;
- “Virgin” distillate materials (kerosene and diesel) which are extracted from the middle of the distillation tower. The kerosene goes to either jet fuel blending, the distillate hydrotreater for ultra-low sulphur diesel production, or No. 6 fuel blending. The diesel goes to the distillate hydrotreater for ultra-low sulphur diesel production;
- Atmospheric gasoil which is further processed in the ISOMAX hydrocracker and converted into primarily gasoline and distillate products;

The residual stream from the bottom of the crude distillation tower or atmospheric tower bottoms are further distilled in the vacuum distillation unit into the following streams:

- Vacuum gasoil from the vacuum tower is routed to the ISOMAX hydrocracker unit to be upgraded primarily into naphtha, kerosene and ultra-low sulphur diesel.

- The residual vacuum tower bottoms stream is routed to the visbreaker and converted into high sulphur fuel oil.

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 platformate, a high octane gasoline stream for use in gasoline blending. A portion of the platformate is further processed in the platformate hydrogenation unit, which 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 the sulphur and nitrogen contaminates from the middle distillates for the production of ultra-low sulphur diesel.

ISOMAX Hydrocracker Unit

The ISOMAX hydrocracker unit uses extremely high heat and pressure to upgrade the atmospheric gasoil and vacuum gasoil streams using catalyst and hydrogen. This process removes contaminants and produces naphtha for gasoline blending and platformer feed, ultra-low sulphur diesel, and jet fuel. The residual stream from the ISOMAX unit are sold as a high value 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 viscosity to meet the requirements for high sulphur fuel oil blending.

Storage and Shipping

Crude oil feedstock and refined products from the various processing units are temporarily stored in designated tanks. We have storage capacity for approximately seven million barrels of feedstocks and refined products. This storage capacity is allocated approximately 50% to crude oil and other feedstock and 50% to refined products. Refined products are ultimately shipped to the United States East Coast market, which 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.

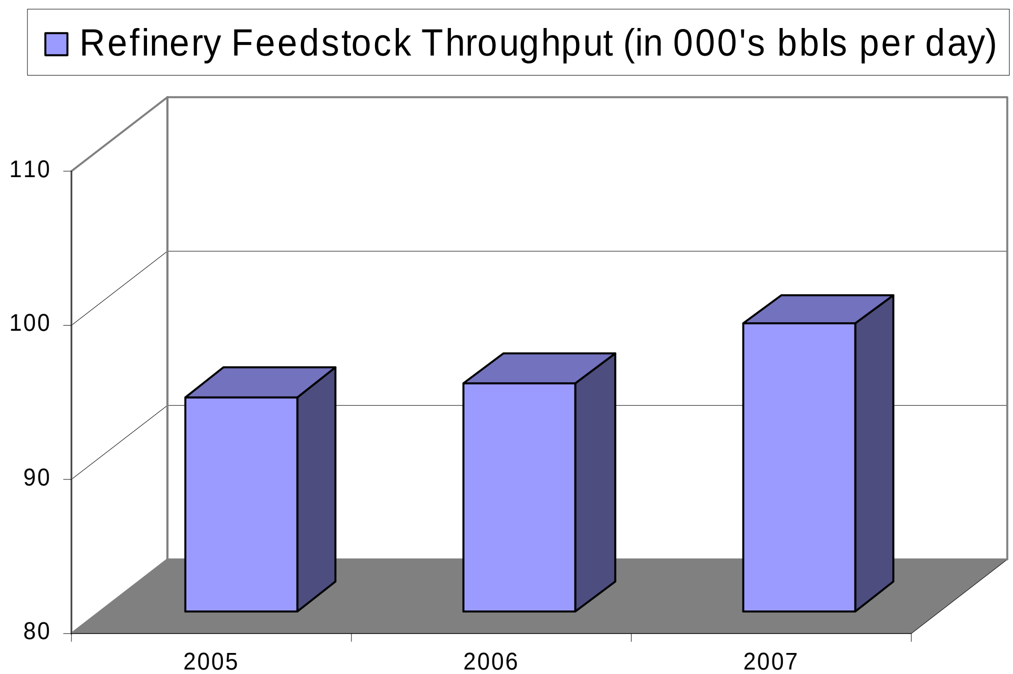
Summary of Refined Products

Over the past three years, the Refinery has produced the following refined products with a total yield of approximately 102% of feedstock:

	2007	2006	2005
	(Mbbls)	(Mbbls)	(Mbbls)
Gasoline and related products	11,515	11,434	12,571
Ultra low sulphur diesel	14,406	14,270	13,736
High sulphur fuel oil	9,843	9,633	9,444
Total Products	35,764	35,337	35,751
Total Liquid Yield (as a % of feedstock)	99%	102%	104%

Operations Reliability

Improving the reliability of the Refinery has been a major focus with significant capital expenditures and a change in maintenance philosophy. Our 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, we have developed an 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 the level of throughput for the period 2005 to 2007 is as follows:



Major refinery shutdowns or turnarounds were undertaken in each of these 3 years.

Supply and Offtake Agreement

Concurrent with the acquisition of North Atlantic by Harvest in 2006, we entered into the SOA with Vitol Refining S.A. The SOA provides that the ownership of substantially all crude oil and other feedstocks and refined product inventory at the Refinery be retained by Vitol Refining S.A. and that during the term of the SOA, Vitol Refining S.A. will be granted the right and obligation to provide crude oil feedstock and other feedstocks for delivery to the Refinery as well as the right and obligation to purchase all refined products produced by the Refinery. The SOA 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 and other feedstocks and sale of refined products as the SOA requires that Vitol

Refining S.A. retain ownership of the crude oil and other feedstocks 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 SOA provides us 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 SOA, we, in consultation with Vitol Refining S.A., request a certain slate of crude oil and other feedstocks and Vitol Refining S.A will be obligated to provide the feedstocks in accordance with the request. The SOA includes a feedstock transfer pricing formula that aggregates the pricing formula for the feedstocks 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 operational price risk management contracts plus a fee of US$0.08 per barrel. The purpose of the operational 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 Harvest 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 SOA 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 SOA in respect of crude oil and other feedstocks 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 SOA requires that Vitol Refining S.A provide us with notice if it plans to sell product outside the U.S. East Coast market which will entitle us to the right, but not the obligation, to share in the incremental profit or loss from such sales.

The SOA 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 SOA 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 and other feedstocks 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 feedstocks, Harvest will be required to purchase the related feedstocks and refined product inventory, 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.

Effective January 20, 2008, we entered into an agreement to sell all of our high sulphur fuel oil not consumed locally at a premium to the New York posted price less a fixed transportation adjustment to one of the world’s largest integrated oil and natural gas producers. This option was provided for in the SOA with Vitol Refining S.A.

Marketing Division

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

Retail Gasoline Business

Our retail gasoline business operates 61 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 9 locations unbranded. Most locations include a convenience store which is independently operated. In 2007, the volume of gasoline and diesel sold at these retail locations represented a market share of approximately 20% of the Newfoundland market. The major competitors in the Newfoundland market are Irving Oil, Imperial Oil and Ultramar.

Retail Heating Fuels Business

Our retail heating fuels business 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.

Bunker Business

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

Overview of Management Structure

Effective in November 2007, Brad Aldrich was appointed, Harvest’s Chief Operating Officer, Downstream. Mr. Aldrich is a senior executive with extensive management experience in petroleum refining and marketing, supply and trading, price risk management, transportation and distribution, and production planning. He has over 27 years of industry experience, including direct responsibility for Clark Refining (an independent petroleum refining and petrochemicals organization) and 12 years of increasing responsibilities with Conoco in their downstream operations. Most recently, Mr. Aldrich held the position of Vice President of Production with Yukos Oil Company, a Russian petroleum company, where he led operations at 11 plants and managed its multi-billion dollar refinery modernization program.

Under Mr. Aldrich’s leadership, our Downstream operations are managed by senior level managers in the following functional areas:

- Production and Maintenance;
- Planning, Economics and Engineering Sciences;
- Marketing;

- Supply and Logistics;
- Finance;
- Human Resources; and
- Support Services.

Employees and Labour Relations

Our Downstream operations have approximately 560 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. During 2007, the collective agreements were renewed for 3 years as at the start of 2008. See "*Risk Factors*".

We maintain a number of employee benefit programs for its employees including basic life insurance and accidental death and dismemberment insurance, extended healthcare and dental coverage, as well as a defined benefit and defined contribution pension plan for its employees and provides certain post retirement health care benefits which cover substantially all employees and their surviving spouses. At December 31, 2007, 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 our audited consolidated financial statements for the year ended December 31, 2007 filed on SEDAR at www.sedar.com.

Environment, Health and Safety Policies and Practices

Consistent with our Upstream business, our Downstream business 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 2007, the Refinery was audited by the Workplace Health, Safety and Compensation Commission and received a rating of 97.2. Consequentially, our workers' compensation assessment rates will be reduced again for the sixth consecutive year. For 2007, the Refinery had a net reduction from the prior year of national pollutant release inventory constituents and greenhouse gas emissions. Finally, the Refinery had no air or effluent water release quality violations in 2007.

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. It is not expected that any of these controls or regulations will affect our Downstream 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.

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 feedstocks. 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.

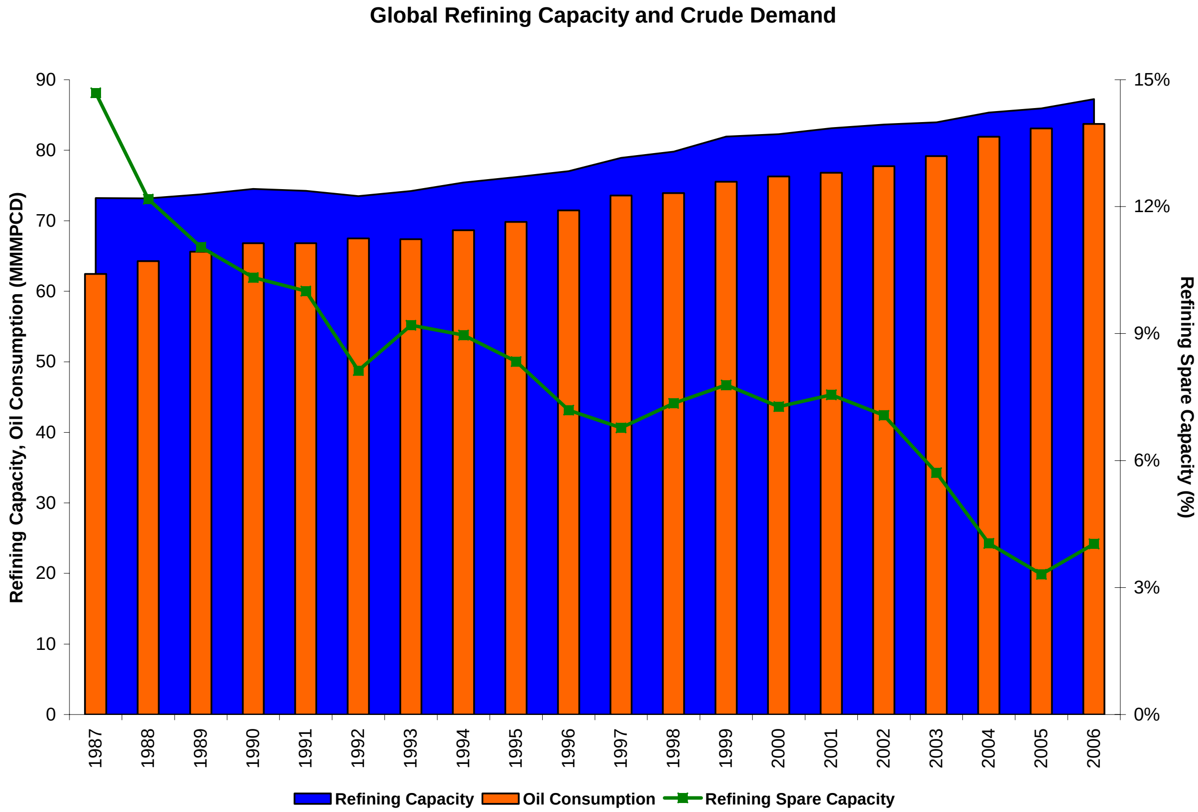
Refining is primarily a margin based business in which the feedstocks and the refined products are commodities. Both crude oil and refined products in each regional market react to a different set of supply/demand and transportation pressures and refiners must balance a number of competing factors in 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 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.

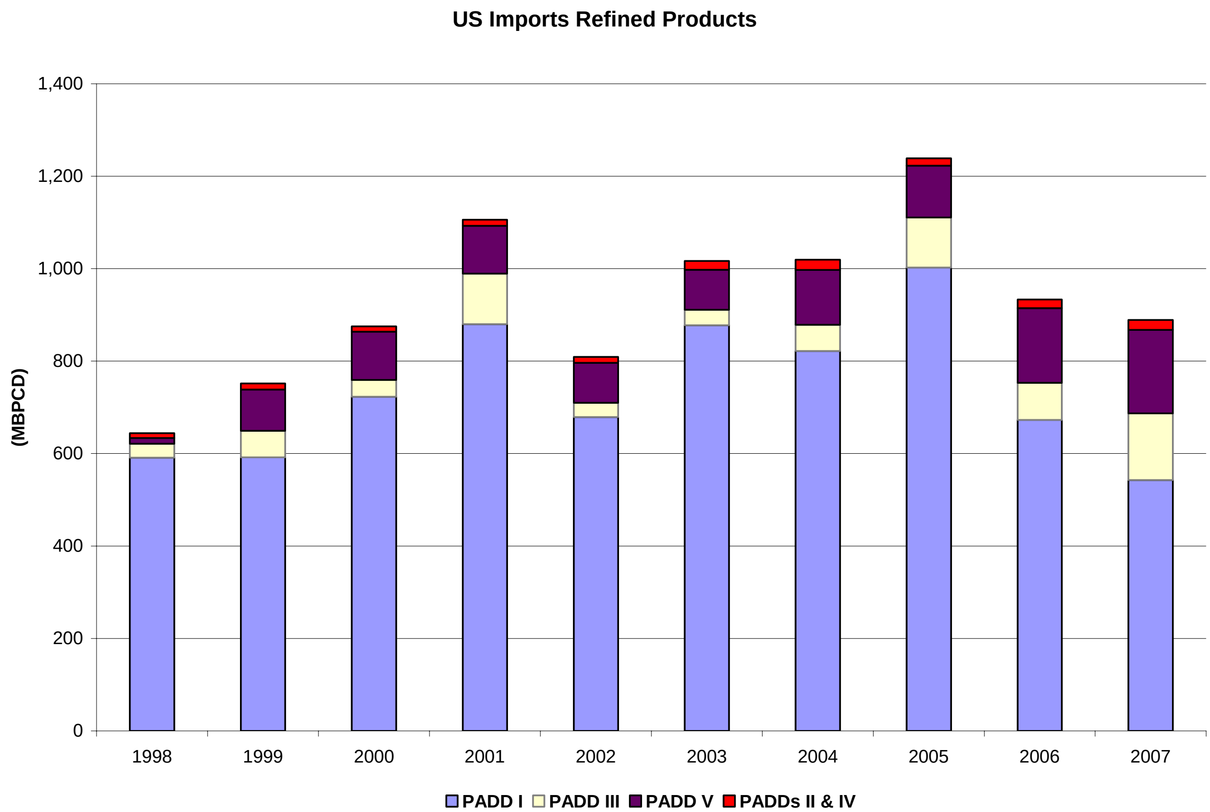
In addition to the global tightening of the refined product supply/demand balance, global crude oil supply has become heavier and higher in sulphur content. The incremental production from most OPEC countries and many other producers has tended to be sour crude, containing more sulphur, while incremental 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.



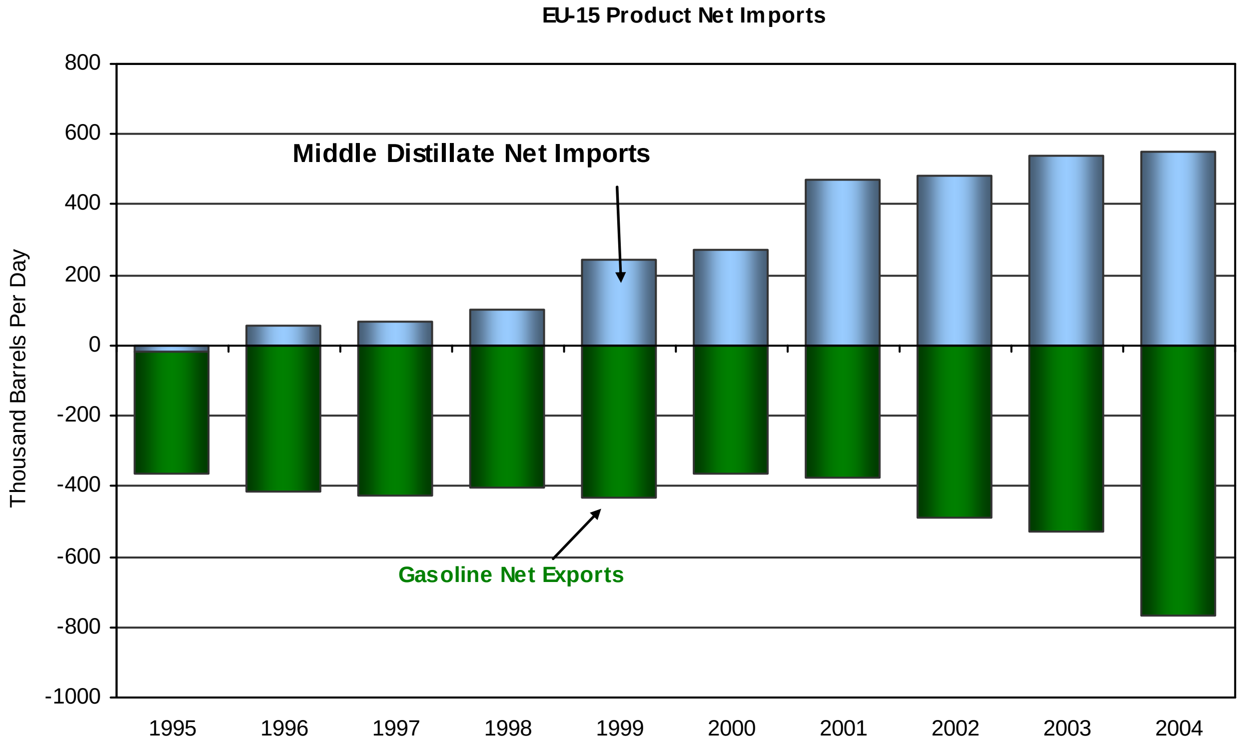
Source: Energy Information Administration

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 refining 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 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 products into the U.S.



Source: Energy Information Administration

Relative to the U.S. import of refined products, the European refined product markets over the past ten years have been characterized as an ever increasing import of distillates, primarily low sulphur diesel, and an increase in the export of gasoline products. Typically, the North American motor fuels market is dominated by gasoline and to a lesser extent diesel, whereas the European motor fuels market is predominately diesel fuel.



Source: Energy Information Administration

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 it 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 Province of Newfoundland and Labrador the sales price of residential home heating fuels and automotive gasoline and diesel fuel sold for consumption 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 in 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 Upstream operations and its Downstream operations are conducted in the same business environment as 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 Upstream operators as well as Downstream 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 Upstream Operations

Volatility of Commodity Prices and Foreign Exchange Risk

The Trust's cash flow from its Upstream operations is dependent on its NPI 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 from operating activities, 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.

Crude Oil Differentials

At the end of 2007, Harvest's production was approximately 49% light and medium gravity crude oil, 24% heavy oil and 27% 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 from operating activities, financial condition and the cash available for distribution to Unitholders as well as funds available for the further 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 and/or dangerous conditions resulting in damage to Harvest Operation's assets and potentially assets of 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 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 a certain 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 prices 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 from operating activities 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 52% 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 NPI 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 from operating activities 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 their cash flows, will be highly dependent on their success in exploiting their 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. Additionally, the potential impact of Canada's ratification of the Kyoto Protocol on Harvest's business and cash from operating activities and cash available for distribution to Unitholders with respect to instituting reductions of greenhouse gases is difficult to quantify at this time. See " Other Upstream Business Information – Environment, Health and Safety Policies and Practices" and "Other Upstream Business Information – Industry Conditions”.

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 Downstream 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

Our Downstream 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 we are 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 Harvest’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 we compete; 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. Harvest does not produce crude oil that can be economically transported to our refinery and must purchase all of its crude oil feedstock at prices that fluctuate with worldwide market conditions and this could significantly impact our earnings and cash flow. We also purchase refined products from third parties for sale to our customers and price changes during the period between purchasing and selling these products could also have a material adverse effect on our business and results of operations, as well as Harvest’s financial condition and cash from operating activities.

We purchase 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, our refinery’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 could also have a material adverse effect on our business and results of operations, as well as Harvest’s financial condition and the cash from operating activities.

.

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 our Downstream operating costs and capital expenditures are primarily in Canadian dollars. Fluctuations in the exchange rates between the U.S. and Canadian dollar result in a currency exchange rate exposure. 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 our exposure.

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

Our refinery receives all of its crude oil feedstock and delivers approximately 90% of its refined products via water borne 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, we 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 an adverse material effect on our business and results of operations, as well as Harvest's financial condition and cash from operating activities.

Since our acquisition of North Atlantic, we have purchased over 75% of our crude oil feedstock from sources in Iraq. We do not maintain long term contracts with any of our crude oil suppliers. To the extent that our crude oil suppliers, particularly suppliers in the Iraq, reduce the volume of crude oil supplied to us as a result of declining production or competition or otherwise, our business, financial condition and results of operations would be adversely affected to the extent that we are not able to find another supplier with a substantial amount and similar type of crude oil. Further, we have no control over the level of development in the fields that currently supply our 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.

We are relying on the creditworthiness of Vitol Refining S.A. for our purchase of crude oil feedstock pursuant to the Supply and Offtake Agreement and rely on the creditworthiness of Harvest to enter into price risk management contracts to reduce 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 us with crude oil and/or 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 may have a material adverse effect on our financial liquidity which could hinder our 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 effect on our business and results of operations, as well as Harvest's financial condition and cash from operating activities.

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, our 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 our business and results of operations, as well as Harvest's financial condition and cash from operating activities.

Our 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 our properties and the properties of others. While we carry property, casualty and business interruption insurance, we do 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 our business and results of operations, as well as Harvest's financial condition and cash from operating activities. Currently, we have the opportunity and intend to consider opportunities to grow our business through the reconfiguration and enhancement of our refinery assets with the suite of expansion or de-bottlenecking projects plus a coker project or a visbreaker project. However, if unanticipated costs occur or our revenues decrease as a result of lower refining margins, operating difficulties or other matters, there may not be sufficient capital to enable us to fund all required capital and operating expenses. There can be no assurance that cash generated by our operations or funding available from debt financings will be available to meet our 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 our storage tanks, or in connection with any facilities to which we send wastes or by-products for treatment or disposal, other than events for which we are indemnified, we 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 we may have to pay for releases or spills, or the amounts that we 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 our business and results of operations, as well as Harvest's financial condition and cash from operating activities.

We operate 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 us to the provisions of Canadian federal laws and the laws of the Province of Newfoundland and Labrador. Among other things, these laws require us to demonstrate our capacity to respond to a "worst case discharge" to a maximum 10,000 metric tonne oil spill. Our 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 our 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, we have contracted with the Eastern Canada Response Corporation to supplement our 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 we may be subject to a significant liability in connection with a discharge.

We have in the past operated service stations with underground storage tanks in the Province of Newfoundland and Labrador, and currently operate 13 retail service stations and 2 cardlock locations with underground storage tanks. We are 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 our 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. While we maintain insurance in respect of such risks, there are no assurances that such insurance will be adequate to fully compensate for any liability we may incur if such risks were to occur.

Aviation Fuel Risks

We produce aviation fuels which involves inherent risks and subjects us to the provisions of Canadian Federal laws. Our product quality assurance programs are extensive; however, these procedures may not be sufficient to detect and prevent contaminants from entering into our aviation fuels which could result in aircraft engines being damaged and/or aircraft crashes. While we maintain insurance in respect of such risks, there are no assurances that such insurance will be adequate to fully compensate for any liability we may incur if such risks were to occur.

Environmental, Health and Safety Risks

Our 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 we fail to comply with these regulations, we 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 us or governmental or court orders that could alter, limit or stop our operations.

Consistent with the experience of other Canadian refineries, environmental laws and regulations have raised operating costs and required significant capital investments at our refinery. We believe that our refinery is substantially compliant with existing laws and regulatory requirements. However, potentially material expenditures could be required in the future may be required for our refinery 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 us 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 our business and results of operations as well as Harvest's financial condition and cash from operating activities.

We are presently subject to litigation and investigations with respect to the use of MTBE and the delivery of contaminated sulphur (see "Legal Proceedings") and although indemnified by the previous owner, there is no assurance that such indemnity will be sufficient to offset our costs and liabilities. We 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

Our future performance depends to a significant degree upon the continued contributions of our senior management team and key technical and operations employees. The loss of one or more members of our Downstream senior management team or a number of key technical and operations employees could result in a disruption to our Downstream operations. In addition, we face competition for these key individuals from competitors, customers and other companies operating in the refining industry and to the extent that we loose members of our senior management team or key technical and operations employees for any reason, we will be required to hire other personnel to manage and operate our Downstream operations and we 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 our future Downstream operations, prospects and viability.

Employee Relations

We have approximately 560 full-time employees and 140 part-time employees in our Downstream operations of which approximately 65% and 90%, respectively, are represented by the United Steel Workers of America pursuant to collective bargaining agreements. Although we have been able to negotiate a new three year contract in late 2007, we may not be able to renegotiate future 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 our Downstream business and results of operations as well as Harvest's financial condition and cash from operating activities.

Competition

We compete with a broad range of refining and marketing companies, including multinational oil companies. Because of their geographic diversity, larger and more complex refineries and greater resources, some of our competitors may be better able to better 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 than we are able to withstand.

Terrorist Attacks, Threats of Attacks or Acts of War

Our Downstream 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 our crude oil suppliers or refined products customers or energy markets generally, and may adversely impact our Downstream business and results of operations as well as Harvest's financial condition and cash from operating activities.

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 our 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 our Downstream business and results of operations as well as Harvest's financial condition and cash from operating activities.

Risks Related to Harvest's Structure

Debt Service

As of March 20, 2008, Harvest has indebtedness of approximately $1.4 billion under its Three Year Extendible Revolving Credit Facility. In addition, letters of credit have been issued to third parties totalling approximately $1.2 million on behalf of Harvest Operations to secure services, primarily electric power, for its Upstream operations. Harvest Operations has also issued US$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 payments 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 NPI 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 Facility 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 NPI 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 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 to 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.

Changes to The Tax Act

On June 22, 2007, the Government of Canada enacted legislation 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. On December 14, 2007, the Government of Canada enacted legislation to implement reductions in the federal income tax rates from 20.5% to 19.5% in 2008 with further reductions scheduled resulting in a 15% tax rate as of January 1, 2012. This legislation effectively implements the Government's plans to apply a tax to public mutual fund trusts commencing January 1, 2011.

However, the legislation provides that any "undue expansion" (being defined as expansion beyond "normal growth") could result in the tax being applied 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. 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. The Department of Finance's guidelines provide that

(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 market capitalization of our Trust Units as of the close of trading on October 31, 2006, 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. At the end of 2007, and after allowing for the continued issuances under our distribution re-investment program, we estimate Harvest could issue approximately $550 million of Trust Units and Convertible Debentures in each of 2008, 2009 and 2010 with any unused “normal growth” available for use prior to 2011. In addition, Harvest is entitled to issue approximately $590 million to replace debt held by the Trust on October 31, 2006.

The Trust continues to consider re-organizing its affairs in a manner that would minimizes taxes and other expenses payable with respect to the operation of the Trust and the Operating Subsidiaries. There can be no assurance that Harvest will be able to reorganize its structure to mitigate the impact of these changes to The Tax Act.

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 2007 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 2007 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.

	2008	**2007**	**2006**	**2005**	**2004**
January	$0.30	$0.38	$0.35	$0.20	$0.20
February	$0.30	$0.38	$0.35	$0.20	$0.20
March	$0.30	$0.38	$0.38	$0.20	$0.20
April	$0.30(2)	$0.38	$0.38	$0.20(1)	$0.20
May		$0.38	$0.38	$0.20	$0.20
June		$0.38	$0.38	$0.20	$0.20
July		$0.38	$0.38	$0.20	$0.20
August		$0.38	$0.38	$0.25	$0.20
September		$0.38	$0.38	$0.35	$0.20
October		$0.38	$0.38	$0.35	$0.20
November		$0.30	$0.38	$0.35	$0.20
December		$0.30	$0.38	$0.35	$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 March 12, 2008 that a monthly cash distribution of $0.30 per Trust Unit will be paid on May 15, 2008 to Unitholders of record on April 22, 2008.

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, February 3, 2006 and January 1, 2008.

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 (one of which series of Debentures matured subsequent to year end and was settled in exchange for the issue of Trust Units). 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.

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, 2007, no Special Voting Units were outstanding.

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, 2008, there were 151,132,746 Trust Units (148,291,170 Trust Units at December 31, 2007) 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, Valiant 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, 2007, the non-resident holders of Trust Units represented approximately 66% 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.

The Unitholders shall reappoint or appoint a successor to the Trustee at each annual meeting of Unitholders. The Trustee may also be removed by Harvest Operations upon delivery of a notice in writing from 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 will present a slate of 8 directors to the Unitholders at the 2008 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 assets 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 Facility 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 provides 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 with the distribution paid by the Trust on June 15, 2007, Unitholders who are residents of the United States are eligible to elect to reinvest distributions to purchase additional Trust Units pursuant to the DRIP Plan.

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. This component of the DRIP Plan is not available to residents of the United States.

Participants in the DRIP Plan (other than residents of the United States) 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, 2008, 17,303,852 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 $452.0 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 larger 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 five 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. One of these two series, "HTE.DB.C" ("VKR.DB" prior to the Viking Arrangement) 10.5% Debentures Due 2008 matured on January 31, 2008 and the $24.3 million principal amount was settled on maturity with the issuance of 1,116,593 Trust Units. The 6.4% Debentures Due 2012 series trade on the TSX under the symbol "HTE.DB.D" ("VKR.DB.A" prior to the Viking Arrangement). 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
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

	TSX Price Range			NYSE Price Range		
	High	Low	Volume	High	Low	Volume
March	$29.22	$25.90	11,430,584	$25.22	$21.97	12,316,050
April	$31.10	$27.74	10,244,956	$28.07	$24.00	10,038,123
May	$33.16	$30.25	13,984,905	$30.70	$27.05	14,253,739
June	$34.48	$31.38	19,605,824	$32.46	$29.47	13,474,838
July	$34.97	$29.50	19,478,671	$33.97	$27.15	17,505,628
August	$31.52	$26.10	17,373,101	$29.74	$24.29	23,146,747
September	$29.40	$25.18	15,463,720	$27.94	$25.15	19,625,622
October	$28.39	$25.92	13,236,903	$29.11	$25.94	20,887,843
November	$26.99	$20.42	12,281,080	$28.96	$20.50	27,496,352
December	$22.22	$19.75	7,729,610	$22.20	$19.80	18,794,208
2008						
January	$23.56	$20.48	10,474,631	$23.24	$20.00	18,167,009
February	$26.00	$22.49	8,552,342	$25.70	$22.51	15,108,961
March (1-20)	$24.13	$22.00	6,543,910	$24.49	$21.44	12,720,843

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.

2007	High	Low	Close	Volume
January	$180.99	$173.00	$180.99	140
February	$190.02	$176.01	$178.32	760
March	$200.00	$193.10	$200.00	600
April	$195.02	$195.02	$195.02	400
May	No trades	No trades	No trades	-
June	$205.00	$205.00	$205.00	220
July	$246.00	$200.13	$238.08	470
August	No trades	No trades	No trades	-
September	No trades	No trades	No trades	-
October	$199.95	$195.94	$195.94	300
November	$185.00	$165.01	$185.00	300
December	No trades	No trades	No trades	-
2008				
January	No trades	No trades	No trades	-
February	$172.00	$172.00	$172.00	100
March (1-20)	No trades	No trades	No trades	-

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.

2007	High	Low	Close	Volume
January	No trades	No trades	No trades	-
February	$170.00	$156.66	$170.00	1,600
March	$165.02	$165.00	$165.00	250
April	$171.04	$165.00	$171.04	1,150
May	$199.33	$170.00	$194.35	810
June	$195.00	$190.02	$190.02	300
July	$195.00	$195.00	$195	100
August	No trades	No trades	No trades	-
September	No trades	No trades	No trades	-
October	$175.22	$153.80	$175.22	450
November	$165.00	$165.00	$165.00	100
December	$117.04	$117.04	$117.04	170
2008				
January	$139.01	$130.77	$130.77	220
February	No trades	No trades	No trades	-
March (1-20)	$145.00	$130.04	$145.00	1,710

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.

2007	High	Low	Close	Volume
January	$100.00	$96.00	$100.00	10,635
February	$102.69	$93.26	$99.25	18,710
March	$103.80	$98.50	$103.80	11,810
April	$104.00	$100.26	$103.11	8,220
May	$107.14	$104.00	$105.00	14,515
June	$109.00	$105.00	$106.41	7,090
July	$112.50	$102.70	$105.03	12,440
August	$102.73	$95.62	$100.00	4,810
September	$102.00	$96.25	$100.00	3,120
October	$100.00	$98.02	$99.00	5,010
November	$99.50	$98.00	$98.25	3,260
December	$98.90	$96.25	$97.00	2,230
2008				
January	$99.99	$97.00	$99.50	1,370
February	$101.75	$98.00	$100.75	1,540
March (1-20)	$102.80	$100.00	$100.00	2,220

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.

2007	High	Low	Close	Volume
January	$105.50	$103.25	$105.00	1,650
February	$106.00	$103.50	$105.00	4,530
March	$104.50	$103.00	$103.51	4,010
April	$105.62	$103.51	$105.62	3,800
May	$112.00	$105.14	$108.50	12,840
June	$123.00	$107.82	$113.10	14,280
July	$120.08	$104.54	$108.22	7,140
August	$106.67	$101.31	$102.10	4,000
September	$104.00	$100.00	$101.12	3,340
October	$103.00	$100.12	$101.14	4,630
November	$101.24	$100.20	$100.46	2,550
December	$100.51	$100.00	$100.00	2,200
2008				
January 1- 31	$109.29	$95.20	$109.15	67,190

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.

2007	High	Low	Close	Volume
January	$92.00	$90.34	$91.30	45600
February	$98.49	$90.76	$96.01	45760
March	$97.50	$92.53	$94.11	50,050
April	$97.88	$93.02	$95.77	64,820
May	$100.00	$96.50	$99.35	47,330
June	$99.74	$98.00	$99.49	40,260
July	$100.00	$97.51	$99.00	27,040
August	$99.29	$91.50	$94.79	14,250
September	$98.99	$88.00	$94.00	16,930
October	$98.00	$91.51	$92.51	25,620
November	$97.99	$82.00	$88.70	34,300
December	$90.00	$77.00	$85.00	31,020
2008				
January	$92.50	$86.00	$92.50	16,530
February	$92.49	$89.51	$91.99	15,050
March (1-20)	$92.24	$90.01	$91.01	14,020

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.

2007	High	Low	Close	Volume
January[1]	$99.00	$95.00	$96.15	231,410
February	$98.97	$96.00	$98.35	364,150
March	$101.75	$96.50	$100.70	379,220
April	$104.00	$99.79	$103.75	198,740
May	$106.75	$103.75	$105.50	337,880
June	$109.45	$105.00	$105.00	310,060
July	$110.00	$102.00	$103.50	220,970
August	$103.40	$95.05	$98.50	109,130
September	$101.00	$95.00	$97.50	98,550
October	$100.00	$95.75	$99.98	197,180
November	$99.98	$89.25	$91.00	176,960
December	$92.00	$82.00	$90.94	90,540
2008				
January	$93.74	$89.00	$92.50	107,160
February	$98.25	$91.56	$96.75	63,000
March (1-20)	$97.00	$94.00	$94.50	100,570

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.

2007	High	Low	Close	Volume
February	$105.75	$99.75	$103.50	573,990
March	$110.65	$102.00	$107.60	421,080
April	$115.00	$105.00	$113.48	291,440
May	$120.90	$112.93	$116.00	363,380
June	$125.87	$115.40	$120.20	808,690
July	$128.00	$110.50	$115.25	304,040
August	$116.00	$101.02	$104.25	17,930
September	$107.00	$100.50	$102.00	16,790
October	$106.00	$100.60	$101.75	138,460
November	$102.50	$89.01	$90.35	22,540
December	$95.00	$83.00	$89.99	129,900
2008				
January	$98.00	$88.01	$94.40	53,590
February	$104.80	$95.50	$101.45	32,320
March (1-20)	$101.50	$95.07	$97.00	12,140

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(3)(10) Calgary, Alberta	Director(9)	515,735	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 (4) Calgary, Alberta	Director(9)	361,064	Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP (a law firm).
M. Bruce Chernoff (4) Calgary, Alberta	Director(9), Chairman	6,442,767 (5)	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) (3) Calgary, Alberta	Director(9)	19,336	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(9)	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) Mississauga, Ontario	Director(9)	13,028	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(3) Calgary, Alberta	Director(9)	12,522	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(4) Calgary, Alberta	Director(9)	9,686	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 Calgary, Alberta	President & Chief Executive Officer	99,979(6)	Professional Engineer, President and Chief Executive Officer of Harvest Operations since February 2006. From May 11, 2004 was President and Chief Executive Officer of VHI; and prior thereto was President of Petrovera Resources.
Robert Fotheringham Calgary, Alberta	Chief Financial Officer	23,393	Chartered Accountant, Chief Financial Officer of Harvest Operations since February 2, 2006; From June 2004 to February 2, 2006 was Vice President, Finance and Chief Financial Officer of VHI; from February 2003 to April 2004 was Chief Financial Officer of Inter Pipeline Fund; and prior thereto was Chief Financial Officer of True North Energy Corporation
Rob Morgan Calgary, Alberta	Chief Operating Officer - Upstream	27,330	Professional Engineer, Chief Operating Officer - Upstream of Harvest Operations since February 2, 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 Calgary, Alberta	Vice President, Corporate	190,076(7)	Professional Engineer, Vice President, Corporate of Harvest Operations since February 2, 2006; from August 2002 to February 2, 2006 was President of Harvest Operations; and prior thereto was Managing Director, Research Capital

Name and Municipality of Residence	Position with Harvest Operations	No. of Trust Units Held [(1)]	Principal Occupation
Brad Aldrich St Louis, Missouri	Chief Operating Officer - Downstream	Nil	Professional Engineer, on November 26, 2007 appointed Chief Operating Officer - Downstream; from 2006 to June 2007 was President & Chief Executive Officer of Changing World Technologies; from 2005 to 2006 was Vice President of Thermodyne Holdings Corp.; and prior thereto was Vice President, Production Yukos Oil Company
Gary Boukall Calgary, Alberta	Vice President, Geosciences	13,933	Professional Geologist, on March 16, 2007 appointed Vice President, geosciences of Harvest Operations; from December 2002 to March 2007 held various positions with Harvest Operations; and 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 to 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 VHI; 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.; and prior thereto was a Team Lead at Petrovera Resources
Neil Sinclair Calgary, Alberta	Vice President, Operations	7,478[(8)]	On March 16, 2007 was 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 VHI; from February 2004 to June 2004 was Manager of Technical Services of Penn West Petroleum Ltd.; and prior thereto was Manager, Operations at Petrovera Resources
Phil Reist Calgary, Alberta	Vice President, Controller	5,607	Chartered Accountant; on March 16, 2007 was appointed Vice President, Controller of Harvest Operations; from February 2, 2006 to March 2007 was Controller of Harvest Operations; from September 2005 to February 2, 2006 was Controller of VHI; from March 2004 to June 2005 was Vice President, Controller of Penn West Petroleum Ltd.; and prior thereto was Vice President, Finance and Controller of Petrovera Resources
Les Hogan Calgary, Alberta	Vice President, Land	Nil	Landman; on December 3, 2007 was appointed Vice President, Land of Harvest Operations; from June 2002 to November 2007 held various positions including Vice President Land and Community Affairs at Pioneer Natural Resources; and prior thereto was Senior Landman of Devon Canada Corporation

Name and Municipality of Residence	Position with Harvest Operations	No. of Trust Units Held (1)	Principal Occupation
David J. Rain Calgary, Alberta	Corporate Secretary	62,205	Chartered Accountant; Corporate Secretary of Harvest Operations since June 2002 and since June 1999 was Vice President, Finance and Chief Financial Officer and a Director of Caribou Capital Corp. (an investment management company); from July 2004 to February 2, 2006 was Vice President and Chief Financial Officer of Harvest Operations; and prior thereto was Vice President, Finance and Chief Financial Officer of Petrobank Energy and Resources Ltd.
Steven Saunders Calgary, Alberta	Assistant Corporate Secretary and Director of Taxation	3,196	Chartered Accountant; on March 16, 2007, was appointed Assistant Corporate Secretary of Harvest Operations and relinquished the Treasurer role; on February 2, 2006 to March 2007 was Treasurer of Harvest Operations and since November 2004 also the Director of Taxation; and prior thereto was International Tax Analyst with EnCana Corporation
Dean Beacon Calgary, Alberta	Treasurer	Nil	On March 16, 2007 appointed Treasurer of Harvest Operations; and prior thereto was a Senior Advisor, Corporate Services at Talisman Energy Inc.

Notes:

(1) Represents all Trust Units beneficially owned, controlled or directed, directly or indirectly as at March 20, 2008. Based upon information provided by the director or officer to the Trust.
(2) Member of the Audit Committee.
(3) Member of the Reserves, Safety and Environment Committee.
(4) Member of the Compensation and Corporate Governance Committee.
(5) 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.
(6) Includes 8,623 Trust Units held by Mr. Zahary's spouse.
(7) Includes 51,767 Trust Units held by Mr. Roorda's spouse.
(8) Includes 415 Trust Units held by Mr. Sinclair’s spouse.
(9) The terms of office of all of the directors will expire at the next annual Unitholders' meeting of the Trust.
(10) Mr. Bennett has not put his name forward to stand for re-election at the next annual meeting of Unitholders.

As at March 27, 2008, the directors, nominated directors and officers of Harvest Operations and their associates and affiliates, as a group, beneficially owned, or controlled or directed, directly or indirectly, approximately 7,862,664 Trust Units or approximately 5.2% 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 as disclosed above, no director or executive officer of Harvest Operations: (a) is, or within 10 years before the date hereof, has been, a director, chief executive officer or chief financial officer of any other issuer that: (i) was subject to an order that was issued while the director or officer was acting in the capacity as director, chief executive office or chief financial officer; or (ii) was subject to an order that was issued after the director or officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer; or

(b) is, or has been within 10 years before the date hereof, a director or executive officer of any issuer that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets. For the purposes of (a) above, "order" means a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

No director or executive officer of Harvest Operations, or to the knowledge of management of the Trust, a unitholder holding a sufficient number of securities of the Trust to affect materially the control of the Trust: (a) is, as at the date hereof, or has been within the 10 years before the date hereof, a director or executive officer of any company (including Harvest Operations) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, state the fact; or (b) has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become 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 director, executive officer or shareholder.

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 Multilateral Instrument 61-101.

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 proceedings which the Trust or any subsidiary of the Trust is or was a party to, or that any of their property is or was the subject of during the year ended December 31, 2007, 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.

There were no penalties or sanctions imposed against the Trust or any subsidiary of the Trust by a Court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2007 or any other penalties or sanctions imposed by a Court or regulatory body against the Trust or any subsidiary of the Trust that would likely be considered important to a reasonable investor in making an investment decision. No settlement agreements were entered into by the Trust or any subsidiary of the Trust with a Court relating to securities legislation or with a securities regulatory authority during the year ended December 31, 2007.

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 beneficially owns, or controls or directs, directly or indirectly 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 Debenture 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 report, valuation, statement or opinion 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 and GLJ, 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 and GLJ 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 27, 2008 which relates to Annual Meeting of Unitholders to be held on May 20, 2008. Additional financial information is provided in Harvest's audited consolidated financial statements and notes there to for the year ended December 31, 2007 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. ("**Harvest Operations**") on behalf of Harvest Energy Trust (the "**Trust**") are responsible for the preparation and disclosure of information with respect to Harvest Operations' and the Trust's other subsidiaries' oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated Harvest Operations' 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 Harvest Operations has:

(a) reviewed Harvest Operations' 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 Harvest Operations' 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 Form 51-101F1 containing reserves data and other oil and natural gas information;

(b) the filing of Form 51-101F2 which is 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(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

March 12, 2008

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

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

1. We have evaluated Harvest Operations' and Harvest Energy Trust's other subsidiaries' reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

2. The reserves data are the responsibility of Harvest Operations' 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).

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

4. 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 Harvest Operations evaluated by us for the year ended December 31, 2007. This table also identifies the respective portions thereof that we have evaluated and reported on to Harvest Operations' 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 11, 2008	Canada	-	1,441,498	-	1,441,498
GLJ Petroleum Consultants Ltd.	March 4, 2008	Canada	-	2,233,055	-	2,233,055
Totals				3,674,553		3,674,553

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

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

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

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

(Signed) GLJ Petroleum Consultants 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 Inc. Gran Tierra Energy Inc.	Mr. Johnson received a Bachelor of Science degree 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 $1,042,650 in 2007 and $1,080,950 in 2006.

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 $369,000 in 2007 and $66,342 in 2006. 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 nil in 2007 and $29,800 in 2006.

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 2007 and in 2006.

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. ("**Harvest Operations**") 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 Harvest Operations, none of whom are members of management of Harvest Operations 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 Harvest Operations 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 Harvest Operations.

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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations of Harvest Energy Trust should be read in conjunction with our audited consolidated financial statements and accompanying notes for the years ended December 31, 2007 and 2006. The information and opinions concerning our future outlook are based on information available at March 12, 2008.

When reviewing our 2007 results and comparing them to 2006, readers should be cognizant that the 2007 results include twelve months of operations from our acquisition of Viking Energy Royalty Trust ("Viking") in February 2006, Birchill Energy Ltd. ("Birchill") in August 2006 and North Atlantic Refining Ltd. ("North Atlantic") in October 2006 and five months from our acquisition of Grand Petroleum Inc. ("Grand") in August 2007 whereas the comparative results in 2006 include only eleven months of operations from our acquisition of Viking, five months of operations from our acquisition of Birchill and ten weeks of operations from our acquisition of North Atlantic. This significantly impacts the comparability of our operations and financial results for the year ended December 31, 2007 to the comparative period in the prior year.

In this MD&A, reference to "Harvest", "we", "us" or "our" refers to Harvest Energy Trust and all of its controlled entities on a consolidated basis. All references are to Canadian dollars unless otherwise indicated. Tabular amounts are in thousands of dollars unless otherwise stated. Natural gas volumes are converted to barrels of oil equivalent ("boe") using the ratio of six thousand cubic feet ("mcf") of natural gas to one barrel of oil ("bbl"). Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. In accordance with Canadian practice, petroleum and natural gas revenues are reported on a gross basis, before deduction of Crown and other royalties, and without including any royalty interests, unless otherwise stated. In addition to disclosing reserves under the requirements of National Instrument 51-101, we also disclose our reserves on a company interest basis which is not a term defined under National Instrument 51-101. This information may not be comparable to similar measures by other issuers.

In this MD&A, we use certain financial reporting measures that are commonly used as benchmarks within the petroleum and natural gas industry such as Earnings From Operations, Cash General and Administrative Expenses and Operating Netbacks and with respect to the refining industry, Earnings (Loss) from Operations and Gross Margin which are each defined in this MD&A. These measures are not defined under Canadian generally accepted accounting principles ("GAAP") and should not be considered in isolation or as an alternative to conventional GAAP measures. Certain of these measures are not necessarily comparable to a similarly titled measure of another issuer. When these measures are used, they are defined as "Non-GAAP" and should be given careful consideration by the reader. Please refer to the discussion under the heading "Non-GAAP Measures" at the end of this MD&A for a detailed discussion of these reporting measures.

FORWARD-LOOKING INFORMATION

This MD&A highlights significant business results and statistics from our consolidated financial statements for the year ended December 31, 2007 and the accompanying notes thereto. In the interest of providing our Unitholders and potential investors with information regarding Harvest, including our assessment of our future plans and operations, this MD&A contains forward-looking statements that involve risks and uncertainties. Such risks and uncertainties include, but are not limited to, risks associated with conventional petroleum and natural gas operations; risks associated with refinery operations, the volatility in commodity prices and currency exchange rates; risks associated with realizing the value of acquisitions; general economic, market and business conditions; changes in environmental legislation and regulations; the availability of sufficient capital from internal and external sources and such other risks and uncertainties described from time to time in our regulatory reports and filings made with securities regulators.

Forward-looking statements in this MD&A include, but are not limited to, the several forward looking statements made in the "Outlook" section as well as statements made throughout with reference to, production volumes, refinery throughput volumes, royalty rates, operating costs, commodity prices, administrative costs, price risk management activity, acquisitions and dispositions, capital spending, reserve estimates, distributions, access to credit facilities, capital taxes, income taxes, cash from operating activities and regulatory changes. For this purpose, any statements that are contained herein that are not statements of historical fact may be deemed to be forward-looking statements. Forward-looking statements often contain terms such as “may”, “will”, “should”, “anticipate”, “expects”, and similar expressions.

Readers are cautioned not to place undue reliance on forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. Although we consider such information reasonable, at the time of preparation, it may prove to be incorrect and actual results may differ materially from those anticipated. We assume no obligation to update forward-looking statements should circumstances, estimates or opinions change, except as required by law. Forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

2007 Financial and Operating Highlights

- Cash from operating activities of $641.3 million, representing an increase of $133.4 million over the prior year primarily due to a full year of downstream operations, the realization of $53.6 million of currency exchange gains and a $39.4 million reduction in cash settlements on our crude oil pricing contracts.
- Upstream operations contributed $624.3 million of cash reflecting production of 60,336 boe/d with strong commodity prices offset by a strengthening of the Canadian dollar and higher operating costs.
- Acquired Grand Petroleum for total cash consideration of $139.3 million representing a cost of approximately $41,000 per flowing barrel and $23.00 per boe for proved and probable reserves complementing our existing oil operations in southeast Saskatchewan.
- Capital spending of $300.7 million in our upstream operations plus $138.2 million of net acquisitions replaced 2007 production with finding and development costs, including changes in future development costs, of $28.10 per boe.
- Downstream operations contributed $165.0 million of cash in 2007 reflecting refining throughput of 114,646 bbl/d and refining margins of US$13.69 per barrel during the first half of the year with an acceleration of turnaround activities significantly reducing throughput and increasing costs during the second half of 2007.
- Increased credit facility to $1.6 billion and extended the maturity date to April 2010 while maintaining the cost of borrowing with a quality syndicate of Canadian and international financial institutions.
- Declared distributions totaling $610.3 million ($4.40 per Trust Unit) with 29% participation in our distribution reinvestment programs providing $178.5 million of additional equity.

SELECTED ANNUAL INFORMATION

The table below provides a summary of our financial and operating results for years ended December 31, 2007 and 2006.

	Year Ended December 31		
($000s except where noted)	**2007**	2006	Change
Revenue, net(1)	**4,069,600**	1,380,825	195%
Cash From Operating Activities	**641,313**	507,885	26%
Per Trust Unit, basic	**$ 4.63**	$ 5.00	(7%)
Per Trust Unit, diluted	**$ 4.30**	$ 4.84	(11%)
Net Income (Loss)(2)	**(25,676)**	136,046	(119%)
Per Trust Unit, basic	**$ (0.19)**	$ 1.34	(114%)
Per Trust Unit, diluted	**$ (0.19)**	$ 1.33	(114%)
Distributions declared	**610,280**	468,787	30%
Distributions declared, per Trust Unit	**$ 4.40**	$ 4.53	(3%)
Distributions declared as a percentage of Cash From Operating Activities	**95%**	92%	3%
Bank debt	**1,279,501**	1,595,663	(20%)
$7^{7/8}$% Senior Notes	**241,148**	291,350	(17%)
Convertible Debentures(3)	**651,768**	601,511	8%
Total long-term financial liabilities(3)	**2,172,417**	2,488,524	(13%)
Total assets	**5,451,683**	5,745,558	(5%)
UPSTREAM OPERATIONS			
Daily Production			
Light to medium oil (bbl/d)	**27,165**	27,482	(1%)
Heavy oil (bbl/d)	**14,469**	13,904	4%
Natural gas liquids (bbl/d)	**2,412**	2,247	7%
Natural gas (mcf/d)	**97,744**	96,578	1%
Total daily sales volumes (boe/d)	**60,336**	59,729	1%
Operating Netback ($/boe)	**29.89**	30.54	2%
Cash capital expenditures	**300,674**	376,881	(20%)
DOWNSTREAM OPERATIONS(4)			
Average daily throughput (bbl/d)	**98,617**	86,890	13%
Aggregate throughput (mbbl)	**35,995**	6,343	467%
Average Refining Margin (US$/bbl)	**10.05**	9.32	8%
Cash capital expenditures	**44,111**	21,411	106%

(1) Revenues are net of royalties.

(2) Net Income includes a future income tax expense of $65.8 million (2006 – a recovery of $2.3 million) and unrealized net losses on risk management contracts of $147.8 million (2006 – net gains of $52.2 million) for the year ended December 31, 2007. Please see Notes 16 and 18 to the Consolidated Financial Statements for further information.

(3) Includes current portion of Convertible Debentures.

(4) Downstream operations acquired on October 19, 2006.

REVIEW OF OVERALL PERFORMANCE

Harvest is an integrated energy trust with our petroleum and natural gas business focused on the operations and further development of assets in western Canada (our "upstream operations") and our refining and marketing business focused on the safe operation of a medium gravity sour crude hydrocracking refinery and a retail and wholesale petroleum marketing business both located in the Province of Newfoundland and Labrador (our "downstream operations").

During 2007, there were two international trends that have significantly impacted Harvest: the appreciation of the Canadian dollar relative to the US dollar and the disruption of international capital markets due to the sub-prime mortgage crisis in the United States and the asset-backed commercial paper problem in Canada. The strengthening of the Canadian dollar tempered the impact of record setting prices for crude oil and refined products as the currency of these pricing benchmarks is denominated in US dollars. For example, the December 31, 2007 closing West Texas Intermediate benchmark price ("WTI") of US$95.98 and a noonday exchange rate of US$1.0120 per Canadian dollar converts to a CDN$94.84 equivalent. This compares to a year earlier when the WTI price was US$61.05 with an exchange rate of US$0.8581 that converted to a CDN$71.15 equivalent resulting in a 57% year-over-year increase in WTI translating to an increase of only 33% in the Canadian dollar equivalent. The impact of a strengthening Canadian dollar for both our upstream business with $937.0 million of crude oil sales and our downstream business with $430.8 million of refining margin is discussed in their respective sections of this MD&A.

In early July 2007, the extent of the sub-prime lending in the United States and the subsequent asset-backed commercial paper problems in Canada severely impacted the non-investment grade debt markets with a tightening of the availability of credit and a re-pricing of credit. We discuss the ongoing impact of this in the Liquidity and Capital Resources section of this MD&A.

During 2007, cash from operating activities totaled $641.3 million, a $133.4 million improvement as compared to $507.9 million in the prior year. While cash generated from our upstream operations of $624.3 million in 2007 remained relatively stable as compared to $626.2 million in the prior year, the cash generated in our downstream operations of $165.0 million in the current year represents a $129.8 million improvement over the prior year reflecting a full year of operations and robust refining margins in the first half of 2007. The increase in contribution from our downstream operations should be considered in light of a $74.1 million increase in interest costs during 2007 also reflecting a full year of ownership. As the Canadian dollar strengthened during 2007, we converted US$654.7 million of US dollar bank loan borrowings to Canadian dollar borrowings crystallizing $47.1 million of currency exchange gains. Cash settlements for our crude oil price risk management contracts totaled $41.5 million in 2007 reflecting a US$57.18 per barrel price cap with 70% participation above the cap, which is a US$13.38 per barrel higher price cap coupled with a 10% increase in participation above the price cap as compared to 2006. The $39.4 million reduction in crude oil risk management losses in 2007 is a result of the US$13.38 higher price cap more than offsetting the US$6.07 increase in the average WTI benchmark price.

Our upstream operations reflected production of 60,336 boe/d in 2007 as compared to 59,729 boe/d in the prior year with the incremental production in 2007 from our 2006 acquisitions of Viking (one month) and Birchill (seven months) and the acquisition of Grand in mid-2007 along with the results of our 2007 capital spending more than offsetting the natural decline and operating disruptions of 2007. Our production decline in 2007 was higher than expected as the assets acquired in the Birchill acquisition included a number of recently completed wells with higher than expected decline rates and our drilling at Hay River in the winter of 2007 did not produce as anticipated resulting in our focus in this area shifting to a re-pressurization of the reservoir. In addition, our operating costs increased to $300.9 million, representing a 23% increase in per unit operating costs to $13.66 per boe reflecting an overheated Alberta oilfield services market. While the average WTI benchmark price increased 9%, our average realized price per boe increased 5% reflecting generally higher discounts for heavy oil and a strengthening of the Canadian dollar.

In early August 2007, we completed our acquisition of Grand for aggregate cash consideration of $139.3 million and quickly integrated its operations into our organization limiting transition costs. At the time of its acquisition, Grand's production averaged approximately 3,400 boe/d comprised of approximately 68% oil and 32% natural gas resulting in the acquisition cost being approximately $41,000 per flowing barrel. In addition, the Grand assets included 46,000 net acres of undeveloped land with supporting seismic. Grand's principal oil producing assets are located in southeast Saskatchewan adjacent to our Hazelwood property with our combined production in this area totaling approximately 3,600 boe/d at year end. In 2008, we are planning to drill 40 wells in southeast Saskatchewan.

Reserve additions in our upstream operations more than replaced our production during 2007 with our proved plus probable reserves at December 31, 2007 totaling 220.9 million boe as compared to 219.9 million boe at the end of 2006. Including changes in future development costs, our 2007 finding and development costs averaged $28.10 per boe while our finding, development and acquisition costs averaged $22.97 per boe as compared to $26.04 per boe and $24.59 per boe, respectively, in the prior year. Included in the 2007 proved plus probable reserve additions are 14.0 million boe attributed to our 2007 capital program and enhanced recovery plans and a further 9.3 million boe for new proved undeveloped reserves which, when coupled with the 10.3 million boe acquired during the year, more than offsets our 2007 production and revisions for underperforming properties. Relative to our 2007 netback price of $29.89, our finding and development costs represent a recycle ratio of 1.06 while our finding, development and acquisition costs represent a recycle ratio of 1.30.

During 2007, our downstream operations generated $165.0 million of cash with $233.1 million generated in the first six months offset by a $68.1 million cash consumption in the last six months. During the first half of 2007, throughput averaged 114,646 bbl/d with our refining margin averaging US$13.69 per barrel which exceeded our expectations. In the second half of the year, our results reflect a significantly reduced refining margin of US$4.16 and the impact of two planned shutdowns. With reduced refining margins appearing early in the third quarter, we accelerated our first shutdown by a few weeks to enable the acceleration of a second shutdown from the spring of 2008, as originally planned, to the fourth quarter of 2007. This acceleration of planned shutdowns better positions us to benefit from anticipated higher refining margins in 2008.

In February 2007, we raised $357.4 million of net proceeds with the issuance of $230 million of principal amount Convertible Debentures and 6,146,750 Trust Units with $289.7 million of proceeds directed to the repayment of our Senior Secured Bridge Credit Facility and the balance applied to our Three Year Extendible Revolving Credit Facility. In April 2007, we increased our Three Year Extendible Revolving Credit Facility from $1.4 billion to $1.6 billion and by October, extended the maturity date of this facility from March 2009 to April 2010 and maintained our syndicate of quality lenders as well as the cost of our borrowing. As the disruptions in the capital markets continue, we are comfortable with the April 2010 maturity date for our credit facilities and may elect to defer further extending the maturity date until capital market conditions improve.

In 2007, we declared distributions to Unitholders totaling $610.3 million ($4.40 per Trust Unit) comprised of ten monthly distributions of $0.38 per Trust Unit and distributions for November and December of $0.30 per Trust Unit. We had maintained our $0.38 per Trust Unit monthly distribution since February 2006 and in light of the impact of a significant strengthening of the Canadian dollar on our crude oil sales revenue and refining margins and the continued high cost of operating in Alberta, we reduced our monthly distribution to $0.30 per Trust Unit effective November 2007 to better balance our cash from operating activities, distributions and capital spending. Unitholder participation in our distribution reinvestment programs generated $178.5 million of equity capital reflecting a 29% average level of participation.

Business Segments

Following our acquisition of North Atlantic in October of 2006, our business has two segments: the upstream operations in western Canada and the downstream operations in the Province of Newfoundland and Labrador. The following table presents selected financial information for our two business segments:

	Year Ended December 31					
	2007			2006		
(in $000's)	**Upstream**	**Downstream**	**Total**	Upstream	Downstream	Total
Revenue[1]	**971,044**	**3,098,556**	**4,069,600**	920,466	460,359	1,380,825
Earnings From Operations[2]	**169,423**	**92,270**	**261,693**	211,418	19,740	231,158
Capital expenditures	**300,674**	**44,111**	**344,785**	376,881	21,411	398,292
Total assets	**3,968,779**	**1,482,903**	**5,451,683**	4,017,761	1,727,797	5,745,558

(1) Revenues are net of royalties.
(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.
(3) 2006 downstream operations are for the period October 19, 2006 to December 31, 2006.

Our Upstream and Downstream operations are each discussed separately in the sections that follow. Additionally, we have included a section entitled 'Risk Management, Financing and Other' that discusses, among other things, our cash flow risk management program and related effects on unitholder distributions.

UPSTREAM OPERATIONS

Financial and Operating Results

Throughout 2007, our production mix was approximately 49% light to medium oil and natural gas liquids, 24% heavy oil and 27% natural gas with our core areas of production located in Alberta, Saskatchewan and British Columbia.

The following summarizes the financial and operating information of our upstream operations for the years ended December 31, 2007 and 2006:

	Year Ended December 31		
(in $000's)	**2007**	2006	Change
Revenues	**$ 1,184,457**	$ 1,120,575	6%
Royalties	**(213,413)**	(200,109)	7%
Net revenues	**971,044**	920,466	5%
Operating expenses	**300,918**	242,474	24%
General and administrative	**34,615**	28,372	22%
Transportation and marketing	**11,946**	12,142	(2%)
Transaction costs	**-**	12,072	n/a
Depreciation, depletion, amortization and accretion	**454,142**	413,988	10%
Earnings From Operations[1]	**169,423**	211,418	(20%)
Cash capital expenditures (excluding acquisitions)	**300,674**	376,881	(20%)
Property and business acquisitions, net of dispositions	**138,158**	2,467,097	(94%)
Daily sales volumes			
Light to medium oil (bbl/d)	**27,165**	27,482	(1%)
Heavy oil (bbl/d)	**14,469**	13,904	4%
Natural gas liquids (bbl/d)	**2,412**	2,247	7%
Natural gas (mcf/d)	**97,744**	96,578	1%
Total (boe/d)	**60,336**	59,729	1%

(1) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

Commodity Price Environment

	Year Ended December 31		
Benchmarks	**2007**	2006	Change
West Texas Intermediate crude oil (US$ per barrel)	**72.31**	66.24	9%
Edmonton light crude oil ($ per barrel)	**76.25**	72.79	5%
Bow River blend crude oil ($ per barrel)	**63.36**	51.04	5%
AECO natural gas daily ($ per mcf)	**6.45**	6.53	(1%)
AECO natural gas monthly ($ per mcf)	**6.61**	6.98	(5%)
Canadian / U.S. dollar exchange rate	**0.935**	0.882	6%

In general, the average West Texas Intermediate ("WTI") crude oil price has increased steadily throughout 2007, beginning the year at US$54.35/bbl in January and exiting the year with a December average price of US$91.74/bbl, resulting in a 2007 annual average price of $72.31/bbl, a 9% increase over the prior year. The average Edmonton light crude oil price ("Edmonton Par") also increased steadily throughout 2007, however to a lesser extent than WTI due to the relative strengthening of the Canadian dollar. The Canadian dollar equivalent of WTI for the year ended December 31, 2007 of

$77.34 would have been $81.98 (or $4.64 higher) had the Canadian/U.S. dollar exchange rate remained unchanged from the prior year.

Heavy oil differentials fluctuate based on a combination of factors including the level of heavy oil inventories, pipeline capacity to deliver heavy crude to U.S. markets and the seasonal demand for heavy oil. Throughout 2007, heavy oil demand was impacted by planned maintenance shutdowns and unplanned disruptions of heavy oil refineries in the United States as well as production from new oil sands projects, resulting in widening differentials. Heavy oil differentials for the last eight quarters are shown below.

	2007				2006			
Differential Benchmarks	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Bow River Blend differential to Edmonton Par	**34.2%**	**30.0%**	**29.4%**	**25.4%**	30.3%	25.8%	22.9%	42.0%

North American natural gas storage inventories throughout 2007 were higher than in prior years, and as a result the benchmark natural gas price fell by 5% compared to the prior year to an average of $6.61/mcf from $6.98/mcf in 2006.

Realized Commodity Prices

The following table provides our average realized price by product for 2007 and 2006.

	Year Ended December 31		
	2007	2006	Change
Light to medium oil ($/bbl)	**64.09**	59.82	7%
Heavy oil ($/bbl)	**46.71**	46.14	1%
Natural gas liquids ($/bbl)	**62.26**	58.54	6%
Natural gas ($/mcf)	**6.94**	6.76	3%
Average realized price ($/boe)	**53.78**	51.40	5%

In 2007 our average realized price was 5% higher than in the prior year, with every product realizing a higher average price than the prior year.

Our realized price for light to medium oil sales increased 7% in 2007 compared to the prior year, reflecting the 5% increase in Edmonton Par pricing over 2006 coupled with improved quality differentials realized on our light to medium oil production relative to the Edmonton Par price during 2007.

Harvest's heavy oil prices were relatively unchanged in 2007 from 2006, despite a 5% year-over-year increase in the Bow River price. This is a result of the relatively heavier gravity production from our two heavy oil acquisitions completed in December 2006 and March 2007.

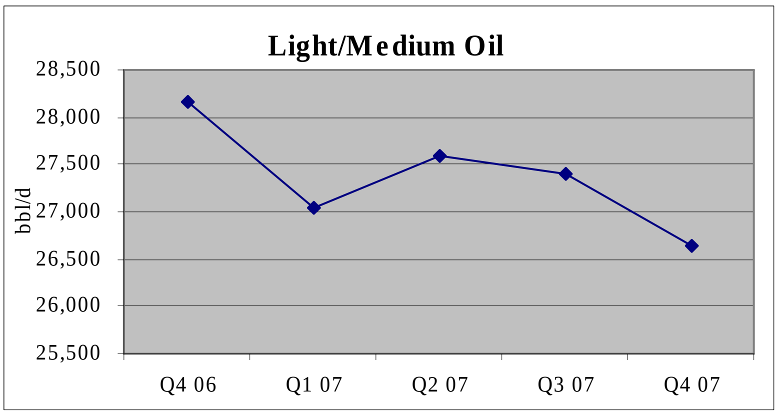
The average realized price for our natural gas production was 3% higher in 2007 than in 2006 compared to reductions of 1% in AECO daily pricing and 5% in AECO monthly pricing over the same period. The increase in our realized natural gas prices relative to 2006 is a result of consolidating our gas marketing arrangements with one third party marketer in late 2006. Throughout 2007 we sold approximately 60% of our natural gas off the AECO daily benchmark and approximately 30% off the AECO monthly benchmark with the remainder sold to aggregators. Additionally, our larger natural gas producing properties generally have a higher than average heat content, which realizes a premium in its pricing.

Sales Volumes

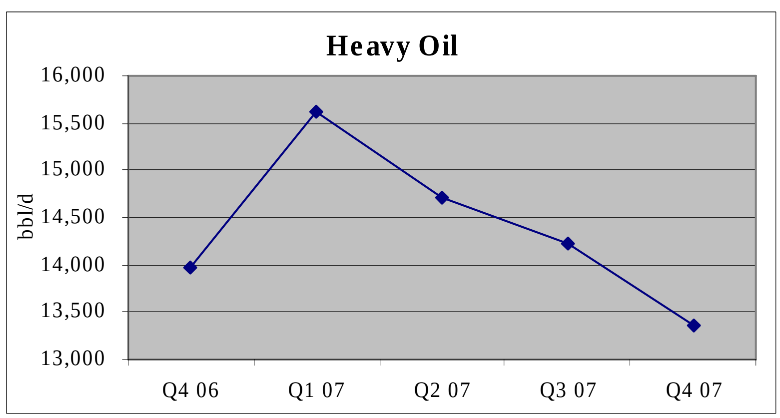
The average daily sales volumes by product were as follows:

	Year Ended December 31				
	2007		2006		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)[1]	**27,165**	**45%**	27,482	46%	(1%)
Heavy oil (bbl/d)	**14,469**	**24%**	13,904	23%	4%
Natural gas liquids (bbl/d)	**2,412**	**4%**	2,247	4%	7%
Total liquids (bbl/d)	**44,046**	**73%**	43,633	73%	1%
Natural gas (mcf/d)	**97,744**	**27%**	96,578	27%	1%
Total oil equivalent (boe/d)	**60,336**	**100%**	59,729	100%	1%

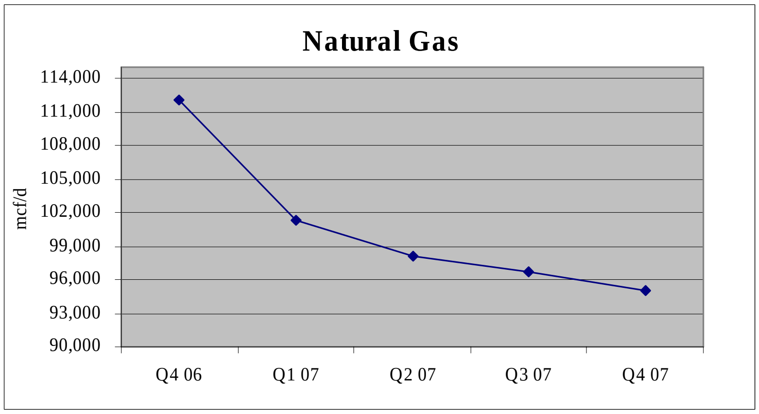
(1) Harvest classifies our oil production, except that produced from Hay River, as light to medium and heavy according to NI 51-101 guidance. The oil produced from Hay River has an average API of 24° (medium grade) and is classified as a light to medium oil, however, it benefits from a heavy oil royalty regime and therefore would be classified as heavy oil according to NI 51-101.



In 2007, our light/medium oil production has trended downward each quarter, except for the second quarter, resulting in an annual average production level of 27,165 bbl/d which is 317 bbl/d or 1% lower than the average in the prior year. In the first quarter, production was disrupted with a major drilling program at Hay River that produces about 15-20% of our total light/medium oil production. In the second quarter, Hay River production resumed, adding an incremental 1,200 bbl/d of initial production from the new wells. In the third quarter, however, steeper than expected declines were experienced in this property, reducing production by 1,750 bbl/d for the quarter which was partially offset by our August 1, 2007 acquisition of Grand that added approximately 1,100 bbl/d of production. In the fourth quarter, production declined a further 500 bbl/d due to continued declines in Hay River as well as normal declines and power outages at our Hazelwood properties in southeast Saskatchewan and the disposals of some minor properties.



Our heavy oil production increased by 4% in 2007 over 2006 with an average of 14,469 bbl/day. Despite this overall increase, our heavy oil production has actually been decreasing each quarter in 2007. Two heavy oil acquisitions, one in late 2006 and one in March 2007 added approximately 1,055 incremental barrels per day of production for the first quarter, offsetting natural declines in other properties and production disruptions associated with "military lockouts" at our Suffield property where our operations are located on a Canadian Forces military base. In the second quarter, our production was 14,719 bbl/d, an 895 bbl/d reduction from the first quarter due to wet spring conditions with soft roads limiting the movement of well servicing equipment and again, the military lockouts at Suffield. Production volumes declined further in the third and fourth quarters as a result of increased water cuts on various large producing wells in the west central Saskatchewan and Lloydminster areas as well as well servicing activities and normal declines.



Our 2007 natural gas production was relatively unchanged from the prior year, averaging 97,744 mcf/d. Our 2006 acquisitions of Birchill and Viking added incremental gas production with our fourth quarter 2006 production volume totaling 112,006 mcf/d. In 2007 we acquired approximately 7,000 mcf/d additional gas production with Grand in the third quarter and focused our capital program on the tie-in of wells drilled in 2006 and expected a downward trend in our natural gas production. While we experienced higher than expected production declines on a few of the Birchill properties acquired in the prior year, our second and third quarter natural gas production was lower due to various third party processing facility turnarounds, specifically in the Crossfield area where quarterly production volumes were reduced by 1,600 mcf/d.

Revenues

		Year Ended December 31			
(000s)		**2007**		2006	Change
Light to medium oil sales	**$**	**635,470**	$	600,061	6%
Heavy oil sales		**246,674**		234,144	5%
Natural gas sales		**247,499**		238,367	4%
Natural gas liquids sales and other		**54,808**		48,003	14%
Total sales revenue		**1,184,451**		1,120,575	6%
Royalties		**(213,413)**		(200,109)	7%
Net Revenues	**$**	**971,038**	$	920,466	5%

Our revenue is impacted by changes to production volumes, commodity prices, and currency exchange rates. Our 2007 total sales revenue of $1,184.5 million is $63.9 million higher than the prior year, of which $54.9 million is attributed to higher realized prices and $9.0 million in attributed to increased production volumes. The price increase reflects the 5% increase in Edmonton Par pricing in 2007 as compared to 2006, while our increased production volume is mainly attributed to the acquisitions that we have completed in late 2006 and throughout 2007 coupled with our 2007 capital spending program.

Light to medium oil sales revenue for 2007 was $35.4 million higher than in the comparative period, due to a $42.3 million favourable price variance offset by a $6.9 million unfavourable volume variance. Increased demand for Canadian light sweet crude oil has resulted in increased realized prices on our light to medium oil production and has had a positive impact on overall revenue while higher than expected decline rates in Hay River and delayed well servicing activity have contributed to an unfavourable volume variance between 2007 and 2006.

Our 2007 heavy oil sales revenue of $246.7 million was $12.5 million higher than in the prior year due to a $9.5 million favourable volume variance resulting from our acquisitions of heavy oil properties and the incremental production from our drilling program and a $3.0 million favourable price variance reflecting the 5% year-over-year increase in Bow River benchmark pricing.

Natural gas sales revenue increased by $9.1 million in 2007 compared to 2006 due to a $6.2 million favourable price variance coupled with a $2.9 million favourable volume variance. The favourable price variance reflects the $0.18/mcf increase in our realized natural gas prices resulting from our consolidation of gas marketing arrangements to a single third party marketer and the favourable volume variance is primarily attributed to the incremental gas production from the acquisition of Birchill in August 2006 and Grand in August 2007.

During 2007, our natural gas liquids and other sales revenue increased by $6.8 million compared to the prior year, attributed to a $3.5 million favourable volume variance and a $3.3 million favourable price variance. Generally, the natural gas liquids volume variance will be aligned with our production of natural gas while the price variances will be aligned with the prices realized for our oil production.

Royalties

We pay Crown, freehold and overriding royalties to the owners of mineral rights from which production is generated. These royalties vary for each property and product and our Crown royalties are based on a sliding scale dependent on production volumes and commodity prices.

Throughout 2007 our net royalties as a percentage of gross revenue were 18.0% (17.9% in 2006) and aggregated to $213.4 million ($200.1 million in 2006). Our 2007 royalty rate is in line with expectations with additional crown royalties assessed on our Hay River properties in 2007, offset by reduced royalties due to increased gas cost allowance credits and crown royalty refunds on some of our shut-in gas-over-bitumen production. See the "Changes in Regulatory Environment" section in this MD&A for further discussion on Alberta's New Royalty Framework.

Operating Expenses

	Year Ended December 31				
(000s except per boe amounts)	**2007**	**Per BOE**	2006	Per BOE	Per BOE Change
Operating expense					
Power	**$ 56,427**	**$ 2.56**	$ 61,056	$ 2.80	(9%)
Workovers	**60,000**	**2.72**	51,151	2.34	16%
Repairs and maintenance	**62,260**	**2.83**	38,969	1.79	58%
Labour – internal	**13,887**	**0.63**	20,719	0.95	(31%)
Processing fees	**28,764**	**1.31**	15,311	0.70	84%
Fuel	**8,725**	**0.40**	7,442	0.34	6%
Labour – external	**15,641**	**0.71**	13,012	0.60	18%
Land leases and property tax	**21,262**	**0.97**	19,319	0.89	9%
Other	**33,952**	**1.53**	15,495	0.71	115%
Total operating expense	**300,918**	**13.66**	242,474	11.12	23%
Transportation and marketing expense	**$ 11,946**	**$ 0.54**	$ 12,142	$ 0.56	(4%)

Our 2007 operating costs totaled $300.9 million as compared to the $242.5 million incurred in 2006. On a per barrel basis, our operating costs have increased to $13.66 in 2007 compared to $11.12 in 2006, representing a 23% increase over the prior year. The largest components of operating expense are workovers and repairs and maintenance costs, and these costs reflect the continued high demand for oilfield services that we experienced throughout the year, resulting in increased overall costs. Additionally, in the third quarter, an extended turnaround at a third-party processing plant in the Crossfield area accounted for a one-time $5.5 million increase in repairs and maintenance expense. The increase in processing fees are directly related to a greater proportion of non-operated properties as a result of our acquisition of Birchill. Generally, we incur higher processing fees on non-operated properties as we own an interest in the well, but may not own an interest in the processing plant and are usually charged a fee for processing which is higher than the per unit cost of operating the facility.

Our 2007 transportation and marketing expense was $11.9 million or $0.54 per boe and is relatively unchanged from $12.1 million or $0.56 per boe in 2006. These costs relate primarily to delivery of natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and to a lesser extent, our costs of trucking clean crude oil to pipeline receipt points. As a result, the total dollar amount of costs fluctuate in relation with our natural gas production volumes and the cost per boe is expected to remain relatively constant.

Electric power costs represented approximately 19% of our total operating costs during 2007. Electric power prices of $66.84/MWh in 2007 were 17% lower than the 2006 average of $80.48/MWh and Harvest recognized a $0.24 per boe reduction in power costs before gains on price risk management contracts as a result of this rate reduction. However, increased power consumption resulting from our acquisition of Birchill in August 2006 and our acquisition of Grand in August 2007 offset the full benefit of the reduction in price. In 2007, our electric power price risk management contracts resulted in a gain of $3.1 million compared to a gain of $11.6 million in the prior year which would be expected with lower power prices. The following table details the electric power costs per boe before and after the impact of our price risk management program.

	Year Ended December 31		
(per boe)	**2007**	2006	Change
Electric power costs	**$ 2.56**	$ 2.80	(9%)
Realized gains on electricity risk management contracts	**(0.14)**	(0.53)	(74%)
Net electric power costs	**$ 2.42**	$ 2.27	7%
Alberta Power Pool electricity price (per MWh)	**$ 66.84**	$ 80.48	(17%)

Approximately 52% of our estimated Alberta electricity usage is protected by fixed price purchase contracts at an average price of $56.69 per MWh through December 2008. These contracts will moderate the impact of future price swings in electric power as will capital projects undertaken that contribute to improving our efficient use of electric power.

Operating Netback

	Year Ended December 31	
(per boe)	**2007**	2006
Revenues	**$ 53.78**	$ 51.40
Royalties	**(9.69)**	(9.18)
Operating expense	**(13.66)**	(11.12)
Transportation and marketing expense	**(0.54)**	(0.56)
Operating netback[1]	**$ 29.89**	$ 30.54

(1) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

Our operating netback represents the net amount realized on a per boe basis after deducting directly related costs. In 2007, our operating netback decreased by $0.65/boe or 2% relative to 2006. The decrease in our operating netback is primarily attributed to a $2.54/boe increase in operating expenses attributed to increased workover and maintenance activity throughout the year and to a lesser extent increased royalties resulting from higher realized prices. Offsetting these factors is a $2.38/boe increase in realized prices for our production compared to the prior year reflecting the increase in Edmonton Par and Bow River pricing throughout the year, as well as increased realized natural gas prices resulting from our change in marketing arrangements in late 2006.

General and Administrative ("G&A") Expense

	Year Ended December 31		
(000s except per boe)	**2007**	2006	Change
Cash G&A[1]	**$ 31,892**	$ 27,485	16%
Unit based compensation expense	**2,723**	887	207%
Total G&A	**$ 34,615**	$ 28,372	22%
Cash G&A per boe ($/boe)	**$ 1.45**	$ 1.26	15%
Transaction costs			
Unit based compensation expense	-	8,974	n/a
Severance and other	-	3,098	n/a
Total Transaction costs	$ -	$ 12,072	n/a

(1) Cash G&A excludes the impact of our unit based compensation expense and for 2006, $12.1 million of one time transaction costs.

For the year ended December 31, 2007, Cash G&A costs increased by $4.4 million (or 16%) compared to the same period in 2006. This increase is mainly related to salaries, which is attributed largely to increased staffing levels from our acquisition of Birchill in August 2006, with a nominal increase associated with our acquisition of Grand. Approximately 75% of our Cash G&A expenses are related to salaries and other employee related costs. Generally, the market for technically qualified staff in the western Canadian petroleum and natural gas industry continues to be tight.

Our unit based compensation plans provide the employee with the option of settling outstanding awards with cash. As a result, our unit based compensation expense is determined using the intrinsic method, being the difference between the Trust Unit trading price and the strike price of the unit awards adjusted for the proportion that is vested. Our Trust Unit market price was $26.15 at January 1, 2007 and on December 31, 2007, our Trust Unit price was $20.63. This reduction in unit value was offset by an increasing number of outstanding awards becoming vested resulting in our 2007 unit based compensation expense of $2.7 million, including a $7.7 million recovery in the last six months of the year as our Trust Unit price decreased from $32.95 at June 30, 2007. Total unit based compensation expense increased $1.8 million in 2007 compared to 2006 due to the increased number of awards granted in 2007 and a large recovery recorded in 2006 resulting from the changes in unit price. In 2006, we recorded transaction costs of $12.1 million which represent one time costs incurred by Harvest as part of the acquisition of Viking in respect of Harvest's outstanding UARs vesting on February 3, 2006 and severance payments made to Harvest employees upon merging with Viking.

Depletion, Depreciation, Amortization and Accretion Expense

	Year Ended December 31		
(000s except per boe)	**2007**	2006	Change
Depletion, depreciation and amortization	**$ 420,184**	$ 381,085	10%
Depletion of capitalized asset retirement costs	**15,621**	16,950	(8%)
Accretion on asset retirement obligation	**18,337**	15,953	15%
Total depletion, depreciation, amortization and accretion	**$ 454,142**	$ 413,988	10%
Per boe	**$ 20.62**	$ 18.99	9%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the year ended December 31, 2007 was $40.2 million higher than the prior year. The increased expense reflects increased production volumes resulting from our acquisitions coupled with higher finding and development costs that have increased our DDA&A rate.

Capital Expenditures

	Year Ended December 31	
(000s)	**2007**	2006
Land and undeveloped lease rentals	**$ 2,785**	$ 9,756
Geological and geophysical	**6,058**	6,709
Drilling and completion	**146,941**	214,964
Well equipment, pipelines and facilities	**134,423**	125,444
Capitalized G&A expenses	**8,353**	13,141
Furniture, leaseholds and office equipment	**2,114**	6,867
Development capital expenditures excluding acquisitions and non-cash items	**300,674**	376,881
Non-cash capital additions (recoveries)	**371**	(533)
Total development capital expenditures excluding acquisitions	**$ 301,045**	$ 376,348

In 2007, Harvest invested $300.7 million in development capital expenditures compared to $376.9 million in 2006. Approximately 49% of these expenditures were costs to drill 182 gross wells with a success rate of 98%, compared to 252 gross wells with a success rate of 98% in 2006. While we continued to focus our drilling activity on oil opportunities (74% of the total net wells drilled) given the strong oil price environment, our central Alberta gas drilling resulted in some particularly successful wells. At Cheddarville, we drilled an Ostracod seismic anomally and discovered a large hydrocarbon charged porous interval. The well was tied-in late in 2007 and has been producing approximately 700 boe/d of sweet natural gas and associated liquids. A second well at Markerville targeting the Ellerslie formation was found to have a productive capacity in the order of 500 boe/d.

Over 70% of our net drilling activity throughout the year took place in the five major areas of Hay River, southeast Saskatchewan, Lloydminster, Suffield and Red Earth. In Hay River we drilled 31 wells and in 2008, we are focusing on additional water injection required to re-pressurize the reservoir. At southeast Saskatchewan, a significant new light oil pool was discovered at Kenosee in 2006 and we drilled 13 gross horizontal wells to begin its exploitation, resulting in production in excess of 600 boe/d by the end of the year. Also at southeast Saskatchewan we drilled a further 20 horizontal wells pursuing light oil accumulations in both the Souris Valley and Tilston formations with a 100% success rate. At Lloydminster and Suffield, we drilled 15 and 11 gross horizontal wells, respectively, accessing heavy oil from the Lloydminster and Glauconitic sandstone formations. At Red Earth, we continued to pursue light oil opportunities in the Slave Point, Granite Wash, and Gillwood formations with a total of 12 gross wells drilled. In addition to our drilling activity we shot a large 3D seismic program on prospective lands acquired in 2006, and we added to our oilsands land inventory with the acquisition of 11,400 net acres bringing our total oilsands rights in the Red Earth area to 29,000 net acres. At Markerville, we drilled 22 gross wells pursuing shallow gas opportunities in the Edmonton Sands formation and liquids rich sweet natural gas in the Pekisko formation.

Our enhanced recovery projects continued to progress in 2007 as we plan the implementation phase for 2008. At Bellshill Lake, we have confirmed through an independent engineering study as well as field trials that increased water injection will translate to a reduction in our current decline rate and result in an improved recovery from this large medium gravity oil pool. At Wainwright, we completed the majority of our laboratory testing and are in the final stages of equipment selection to begin construction on our ASP (Alkaline Surfactant Polymer) flood pilot that could access incremental medium oil if implemented field wide. A pilot will test this technology on an area representing approximately 10% of the pool starting in the 4th quarter of 2008. At Suffield, in 2008 we will launch an enhanced waterflood to increase the volume of water injection with expectation of a reduction in decline rates as well as an increase in recoverable reserves.

The $134.4 million of well equipment, pipelines and facilities expenditures during 2007 include a number of initiatives to improve the efficiency of our Hay River operations including the construction of an all season access road, the installation of natural gas infrastructure to eliminate flaring of produced natural gas, an electrical distribution system as well as well equipment required to bring new wells into production. Various other initiatives have been undertaken to improve overall efficiency in other areas, including an expansion of our oil processing facilities at Red Earth intended to optimize Slave Point light oil production and to provide the necessary infrastructure to accommodate our 2008 drilling program. An emulsion processing facility at Kenosee in southeast Saskatchewan has been constructed, also to accommodate the incremental production from our 2008 drilling program. Replacement of pipelines at Kilarney, Hayter and Bashaw are included as part of Harvest's capital maintenance program to maintain the integrity of our producing infrastructure.

The following summarizes Harvest's participation in gross and net wells drilled during 2007:

	Total Wells		**Successful Wells**		**Abandoned Wells**	
Area	**Gross[1]**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Hay River	31.0	31.0	31.0	31.0	-	-
Southeast Saskatchewan	33.0	29.0	33.0	29.0	-	-
Markerville	22.0	9.6	22.0	9.6	-	-
Lloydminster	15.0	15.0	15.0	15.0	-	-
Red Earth	12.0	8.5	12.0	8.5	-	-
Suffield	11.0	11.0	9.0	9.0	2.0	2.0
Hayter	7.0	5.3	7.0	5.3	-	-
Other Areas	51.0	22.2	49.0	21.6	2.0	0.6
Total	182.0	131.6	178.0	129.0	4.0	2.6

(1) Excludes 31 additional wells that we have an overriding royalty interest in.

Our 2007 capital program, along with our acquisitions and divestitures, more than replaced our production on a proved plus probable basis with 2007 year end reserves of 220.9 million boe, essentially unchanged from 219.9 million boe at the end of 2006. Including changes in future development costs, our 2007 finding and development cost averaged $28.10 per boe while our finding, development and acquisition costs averaged $22.97 per boe as compared to $26.04 per boe and $24.59 per boe, respectively, in the prior year. Based on the forecast prices and costs of our independent reservoir engineers as at December 31, 2007, the net present value of our future net revenues from proved reserves using a 10% discount rate is $2,865.8 million and $3,675.1 million from proved plus probable reserves. Relative to our 2007 netback price of $29.89/boe, our finding and development costs result in a recycle ratio of 1.06 while our finding, development and acquisition costs result in a recycle ratio of 1.30. Based on our 2007 production of 22.0 million boe, our 2007 year end proved reserves represent a reserve life index of 7 years while our proved plus probable reserves represent a reserve life index of 10 years.

Corporate Acquisitions

Effective March 1, 2007, we acquired a private petroleum and natural gas corporation for cash consideration of $30.6 million which added approximately 1,500 bbl/d of western Saskatchewan heavy oil production which is adjacent to our existing operations in the area.

In early August 2007, we completed the acquisition of Grand for aggregate consideration of approximately $139.3 million, acquiring approximately 3,400 boe/d of production with proved plus probable (P+P) reserves of 6 million boe, composed of approximately 67% oil. The Grand assets include a significant presence in southeast Saskatchewan, the Sylvan Lake/Markerville area and eastern Alberta which are adjacent to existing Harvest operations with complementary drilling opportunities. We also acquired 65,000 acres (46,000 net acres) of undeveloped land with supporting seismic data providing further development opportunities. This acquisition represents an acquisition cost of approximately $41,000 per flowing boe and $23.00 per boe of proved and probable reserves.

Goodwill

Goodwill is recorded when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of that acquired business. At December 31, 2006, we had recorded $656.2 million of goodwill related to our upstream segment and during 2007 we added an additional $20.5 million of goodwill with our purchase of Grand. The goodwill balance is assessed annually for impairment or more frequently if events or changes in circumstances occur that would reasonably be expected to reduce the fair value of the acquired business to a level below its carrying amount. To date, no charge for impairment of this goodwill has been made.

Asset Retirement Obligation ("ARO")

In connection with property acquisitions and development expenditures, we record the fair value of the ARO as a liability in the same year as the expenditure occurs. The associated asset retirement costs are capitalized as part of the carrying amount of the assets and are depleted and depreciated over our estimated net proved reserves. Once the initial ARO is measured, it is adjusted at the end of each period to reflect the passage of time as well as changes in the estimated future cash flows of the underlying obligation. Our asset retirement obligation increased by $11.0 million during the year ended December 31, 2007. The increase is a result of additional obligations incurred through our corporate acquisitions and drilling activity throughout the year as well as accretion expense, offset by $13.1 million of actual asset retirement expenditures incurred.

DOWNSTREAM OPERATIONS

Our downstream operations, operating under the North Atlantic trade name, are comprised of a medium gravity sour crude hydrocracking refinery with a 115,000 bbl/d nameplate capacity and a marketing division with 64 gasoline outlets, a home fuel business and a commercial and wholesale petroleum products business, all located in the Province of Newfoundland and Labrador. The sales volume of our marketing division represents approximately 20% of the Newfoundland market.

Since the acquisition of North Atlantic, our quarter-over-quarter operating results of our downstream business have not been very comparable due to planned shutdowns for refinery turnaround activities and the seasonal demand for refined products affecting throughput volumes and the volatility of refining margins, respectively. For the period ending December 31, 2006, our results reflect the impact of an extended turnaround commencing October 1, 2006 with the refinery returning to full operations near the end of November 2006 only to experience additional downtime in December 2006 due to a pipe rupture and a disruption in electric power service. Our operations for the first six months ended June 30, 2007 reflect solid operating performance with throughput of 114,646 bbl/d and robust refining margins generating $232.1 million of cash while the performance for the next six months reflect the impact of two planned shutdowns and substantially weaker refining margins. Accordingly, the analysis of our downstream operations will not be a comparison of one operating period with another but rather a review of the activities for each period and their impact on operating results.

The following summarizes our downstream financial and operational results for 2007 and 2006:

(in $000's except where noted below)	**Six Months Ended June 30, 2007**	**Six Months Ended December 31, 2007**	**Year Ended December 31, 2007**	**For the Period October 19, 2006 to December 31, 2006**
Revenues	1,684,432	1,414,124	3,098,556	460,359
Purchased feedstock for processing and products purchased for resale	1,340,938	1,326,776	2,667,714	386,014
Gross Margin[(1)]	343,494	87,348	430,842	74,345
Costs and expenses				
Operating expense	51,945	50,531	102,476	18,378
Purchased energy expense	42,337	49,991	92,328	15,685
Turnaround and catalyst expense	-	34,486	34,486	-
Marketing expense	16,402	18,568	34,970	5,060
General and Administrative	702	1,011	1,713	-
Depreciation and amortization expense	37,574	35,026	72,600	15,482
Earnings (loss) from operations[(1)]	194,534	(102,265)	92,269	19,740
Cash capital expenditures	14,754	29,357	44,111	21,411
Feedstock volume (bbl/day)[(2)]	114,646	82,849	98,617	86,890
Yield (000's barrels)				
Gasoline and related products	6,689	4,826	11,515	1,875
Ultra low sulphur diesel and jet fuel	8,233	6,173	14,406	2,624
High sulphur fuel oil	5,695	4,148	9,843	1,752
Total	20,617	15,147	35,764	6,251
Average Refining Margin (US$bbl)[(3)]	13.69	4.16	10.05	9.32

(1) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A
(2) Barrels per day are calculated using total barrels of crude oil feedstock and Vacuum Gas Oil.
(3) Average refining margin is calculated based on per barrel of throughput

Overview of Downstream Financial Performance

During 2007, our downstream operations generated $165.0 million of cash with $233.1 million generated in the first six months offset by a $68.1 million cash deficiency in the last six months of the year. Earnings from operations of $92.3 million for 2007 is comprised of earnings of $194.5 during the first six months and a loss of $102.3 million during the last six months. Our results for the first six months of 2007 reflect solid operating performance with throughput of 114,646 bbl/d and unit operating costs (operating expenses plus the cost of purchased energy) averaging $4.12 per barrel with an average refining margin of US$13.69 per barrel. During the first half of 2007, the sale of our refined products increased from US$71.03 per barrel to US$94.90 for gasoline and from US$74.18 per barrel to US$85.43 for distillate from the first quarter to second quarter, respectively, while the cost of our feedstock (crude oil and vacuum gas oil) increased from US$51.73 per barrel in the first quarter to US$60.46 in the second quarter resulting in robust refining margins during the first six months of 2007.

Our downstream operations during the last six months of 2007 reflect significantly reduced refining margins and two planned shutdowns. During the third quarter of 2007, increases in the cost of our crude oil feedstock were not accompanied with higher gasoline and distillate prices resulting in the significant erosion of our refining margin from US$15.64 per barrel of throughput in the second quarter to US$3.08 in the third quarter. Anticipating that refining margins were more likely to improve in the first half of 2008 than in the fourth quarter of 2007, we accelerated our first shutdown by a few weeks to enable the acceleration of a second shutdown from the spring of 2008, as originally planned, to the fourth quarter of 2007. During the first shutdown in September, we replaced and regenerated the catalyst in the Isomax and Platformer units, respectively, as well as completed routine inspection and maintenance on these units. Subsequent to the re-commissioning of the Isomax and Platformer units in mid-October, we initiated a shutdown of the crude and vacuum units and replaced catalyst in the distillate hydrotreater unit. In addition to advancing the re-certification of vessels in these units, the second shutdown included a significant improvement in our production of vacuum gas oil (“VGO”) thereby reducing the amount of VGO required to be purchased in the future to optimize the Isomax throughput. By early December, the refinery had returned to full operation with throughput averaging 109,611 bbl/d as compared to throughput of 90,440 bbl/d in September, 38,741 bbl/d in October and 35,981 bbl/d in November during the two shutdowns. This acceleration of planned shutdowns better positions us to benefit from anticipated higher margins in early 2008.

Comparatively, our refinery operating results for the period from October 19, 2006 through December 31, 2006 reflect the impact of an extended turnaround that commenced October 1, 2006 with the refinery returning to full operations near the end of November 2006. Our results for 2006 also include additional downtime in December as a result of a pipe rupture in the naphtha hydrotreater and a disruption in electric power service from the local utility which impacted the month’s throughput by approximately 3,000 bbl/d.

Refining Benchmark Prices

The North American refining industry has numerous benchmark pricing indicators against which to compare refinery gross margin performance. Typically, these gross margin indicators include prices for refined products such as Reformulated Blendstock for Oxygenate Blending gasoline ("RBOB gasoline") and heating oil. The New York Mercantile Exchange ("NYMEX") "2-1-1 Crack Spread" is such an indicator and is calculated assuming that the processing of two barrels of light sweet crude oil (defined as a WTI quality) produces one barrel of RBOB gasoline and one barrel of heating oil delivered to the New York market, where product prices are set in relation to NYMEX gasoline and NYMEX heating oil prices. The following average pricing indicators are provided as reference points with which to index our refinery's performance:

	Six Months Ended June 30, 2007	Six Months Ended December 31, 2007	Year Ended December 31, 2007	October 19, 2006 to December 31, 2006
West Texas Intermediate (US$ per barrel)	61.60	83.03	72.31	60.44
Brent (US$ per barrel)	63.65	81.69	72.67	60.76
RBOB gasoline (US$ per barrel)	82.62	91.10	86.86	66.78
Heating Oil (US$ per barrel)	75.15	96.15	85.65	71.82
High Sulphur Fuel Oil (US$ per barrel)	45.11	62.93	54.02	40.94
2-1-1 Crack Spread (US$ per barrel)	17.29	10.60	13.95	8.86
Canadian / US dollar exchange rate	0.881	0.988	0.935	0.883

During 2007, the seasonality of the North American refining industry was evident as the "2-1-1 Crack Spread" averaged US$17.29 for the first six months of the year and US$10.60 for the last six months. The robust crack spreads during the first half of 2007 also reflected the impact of numerous refinery outages and an extremely tight gasoline supply situation in the Midwest US markets. As compared to the October 19, 2006 through December 31, 2006 period, RBOB gasoline and heating oil prices increased by 24% and 5%, respectively, during the first six months of 2007 while the WTI benchmark price increased a meager 2% resulting in a 95% increase in the "2-1-1 Crack Spread."

During the six months ended December 31, 2007, RBOB gasoline and heating oil prices increased an additional 10% and 28%, respectively, as compared to the first six months of 2007 while the WTI benchmark price increased by 35% and the "2-1-1 Crack Spread" narrowed by 39% to US$10.60. The squeezing of refining margins during the second half of 2007 reflects a balanced alignment of crude oil prices with refined product pricing as well as an increase in available refining capacity with the resolution of the outages encountered earlier in the year.

The significant strengthening of the Canadian dollar during the last six months of 2007 had a significant financial impact on the results of our downstream operations. The 12% change in the Canadian / US dollar exchange rate between the first six months of 2007 and the last six months of the year compounded the 39% drop in the "2-1-1 Crack Spread" in US dollar terms to a 45% drop if converted to a Canadian dollar equivalent.

As compared to the "2-1-1 Crack Spread" industry indicator, our refinery's production differs in that it also produces approximately 25% to 30% high sulphur fuel oil not represented in the "2-1-1 Crack Spread" indicator. High sulphur fuel oil typically sells US$15.00 to US$20.00 lower than the WTI benchmark price resulting in a negative contribution to our gross margin relative to the "2-1-1 Crack Spread." However, our refinery also processes a medium gravity sour crude oil rather than a WTI quality of light sweet crude oil which sells at a discount to the WTI benchmark price and we purchase approximately 8,000 to 10,000 bbl/d of VGO to optimize the throughput of our Isomax unit at a premium price to the WTI benchmark price which further complicates the comparison of our refining margin to the "2-1-1 Crack Spread."

Downstream Gross Margin

The downstream gross margin is comprised of the refining margins as well as the margin on our marketing and other related businesses. A comparison of the gross margin contribution from the refinery and marketing divisions for each of the first six months and last six months of 2007 is presented below:

	Six Months Ended June 30, 2007			Six Months Ended December 31, 2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	**Refining**	**Marketing**	**Total**
Sales revenue[1]	**1,640,447**	**206,694**	**1,684,432**	**1,342,208**	**297,681**	**1,414,124**
Cost of feedstock for processing and products for resale[1]	**1,317,886**	**185,761**	**1,340,938**	**1,278,021**	**274,520**	**1,326,776**
Gross margin[2]	**322,561**	**20,933**	**343,494**	**64,187**	**23,161**	**87,348**
Average Refining Margin (US$/bbl)	**$13.69**			**$4.16**		

[1] Downstream operations sales revenue and cost of products for processing and resale are net of inter-segment sales of $162,709,000 and $225,765,000, reflecting the refined products produced by the refinery and sold by Marketing Division for the six months ended June 30, 2007 and December 31, 2007, respectively.
[2] These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

During 2007, our gross margin from refining totaled $386.7 million comprised of $322.6 million earned in the first six months of 2007 and $64.2 million earned in last six months of the year with our average refining margin for the year of US$10.05 per barrel of throughput comprised of US$13.69 for the first six months and US$4.16 for the last six months. The review of our refining margins is a combination of two analysis: (1) a comparison of refined product prices relative to the North American crude oil benchmark price, WTI, and (2) an analysis of the cost of our crude oil feedstock as compared to the WTI price.

The Marketing Division of our downstream operations is comprised of both retail and wholesale distribution of gasoline, home heating fuels and related appliances as well as the revenues from marine services including tugboat revenues. The Marketing Division has provided relatively stable gross margins with $9.8 million, $11.1 million, $11.8 million and $11.4 million reported for the first, second, third and fourth quarters, respectively, with the aggregate gross margin for 2007 totaling $44.1 million.

Refined Product Sales Revenue

Our refinery sales revenue is dependent on our yield of refined products and their sales value. Although our yield can be altered slightly to react to market conditions and seasonal demand, product yields are primarily impacted by the type of crude oil feedstock as well as refinery performance. Our sales volume closely approximates our production as the Supply and Offtake Agreement requires that substantially all refined products produced be purchased by Vitol Refining S.A. as they leave the refinery with the exception of jet fuel and certain other products marketed by our downstream marketing division primarily in the Province of Newfoundland and Labrador. The Supply and Offtake Agreement includes pricing formulas for refined product purchases whereby the price for refined products delivered from one Wednesday to the next is determined using average benchmark prices for the period commencing on the following Monday through Friday adjusted for actual shipping costs and product quality differentials. This pricing, which is based on a subsequent period, accelerates the impact of pricing trends on our sales prices and results in our prices being based on a slightly different time period than the monthly average benchmark prices, but generally, our refined product sales prices reflect the cost of crude oil feedstock, a refining crack spread and a quality differential adjustment with each impacted by global supply and demand. For more information on the Supply and Offtake Agreement, see the description of the Supply and Offtake Agreement in our Annual Information Form for the year ended December 31, 2007 to be filed on SEDAR at www.sedar.com.

A comparison of our refinery product yield, pricing and revenue for each of the first six months and last six months of 2007 is presented below.

	Six Months Ended June 30, 2007			Six Months Ended December 31, 2007		
	Refinery Revenues	**Volume**	**Sales Price(1)**	**Refinery Revenues**	**Volume**	**Sales Price(1)**
	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)
Gasoline products	**611,618**	**6,543**	**82.35/1.96**	**476,597**	**5,183**	**90.85/2.16**
Low & ultra low sulphur diesel & jet fuel	**727,656**	**8,066**	**79.48/1.89**	**611,732**	**6,179**	**97.81/2.33**
High sulphur fuel oil	**301,173**	**5,693**	**46.61**	**253,879**	**4,047**	**61.98**
	1,640,447	**20,302**		**1,342,208**	**15,409**	
Inventory adjustment		**315**			**(262)**	
Total production		**20,617**			**15,147**	
Yield (as a % of Feedstock) (2)		**99%**			**99%**	

(1) Average product sales prices are based on the deliveries at our refinery loading facilities

(2) After adjusting for changes in inventory held for resale

During 2007, gasoline product comprised 32% of our refinery output while ultra low sulphur diesel and jet fuel (or "distillates") accounted for 40% and high sulphur fuel oil the residual 28%. Despite the two shutdowns in the last six months of 2007, our product yields during this period were substantially unchanged from the product slate produced during the first six months of the year. Our yield of 32% gasoline products and 40% distillates results in 72% of our production closely mirroring the "2-1-1 Crack Spread" benchmark.

Relative to the benchmark NYMEX RBOB gasoline price, our price for gasoline products closely mirrored the benchmark price with a minor difference of less than a US$0.01 per US gallon in both the first half and second half of 2007 as compared to a US$0.11 per US gallon discount in the period from October 19, 2006 through December 31, 2006. During the 2006 period, commodity prices were relatively stable resulting in the discount approximating the expected shipping cost to the New York Harbour. While in 2007, the expected shipping costs were offset by the benefit of a 10 day delay in a rising price environment.

For our ultra low sulphur diesel and jet fuel products, we realized a US$0.05 per US gallon premium over NYMEX heating oil prices during 2007 which is primarily attributed to the 10 day delay in our pricing in a rising price environment and to a lesser extent, our distillate products being generally a mix of higher valued distillate products than the benchmark heating oil product offset by the expected shipping cost to the New York Harbour. In addition, from time-to-time, there will be modest differences in the differential between the physical selling prices for our refined products in the New York Harbour and the NYMEX benchmark prices. The US$0.05 per US gallon average premium for 2007 is comprised of a US$0.10 per US gallon premium for the first six months and a US$0.04 premium during the last six months of the year. During the period from October 19, 2006 through December 31, 2006, we realized a US$0.03 per US gallon premium over the NYMEX heating oil benchmark price.

Our high sulphur fuel oil was sold at an average discount of US$19.03 per barrel relative to the WTI benchmark price in 2007 reflecting the heavier gravity and higher sulphur content of our fuel oil product. During the first six months of 2007, our high sulphur fuel oil sold at an average discount of US$14.99 per barrel as compared to US$21.05 during the last six months of the year.

Overall, relative to the WTI benchmark price, our refined products received a net premium of US$5.78 per barrel during 2007 comprised of US$9.59 in the first six months and US$3.03 in the last six months of the year.

Refinery Feedstock

We purchase crude oil feedstock from Vitol Refining S.A. pursuant to the terms of the Supply and Offtake Agreement which includes financing and operational hedging of crude oil pricing commitments. This enables the price of our feedstock to float with the WTI benchmark price for the period from pricing through to the date it is charged to the refinery. The Supply and Offtake Agreement includes pricing formulas for feedstock purchases similar to the pricing for refined product sales whereby there is a 10 day delay in pricing. This pricing based on a subsequent period accelerates the impact of pricing trends on the cost of our feedstock and results in our costs being based on a slightly different time period than the monthly average WTI benchmark price.

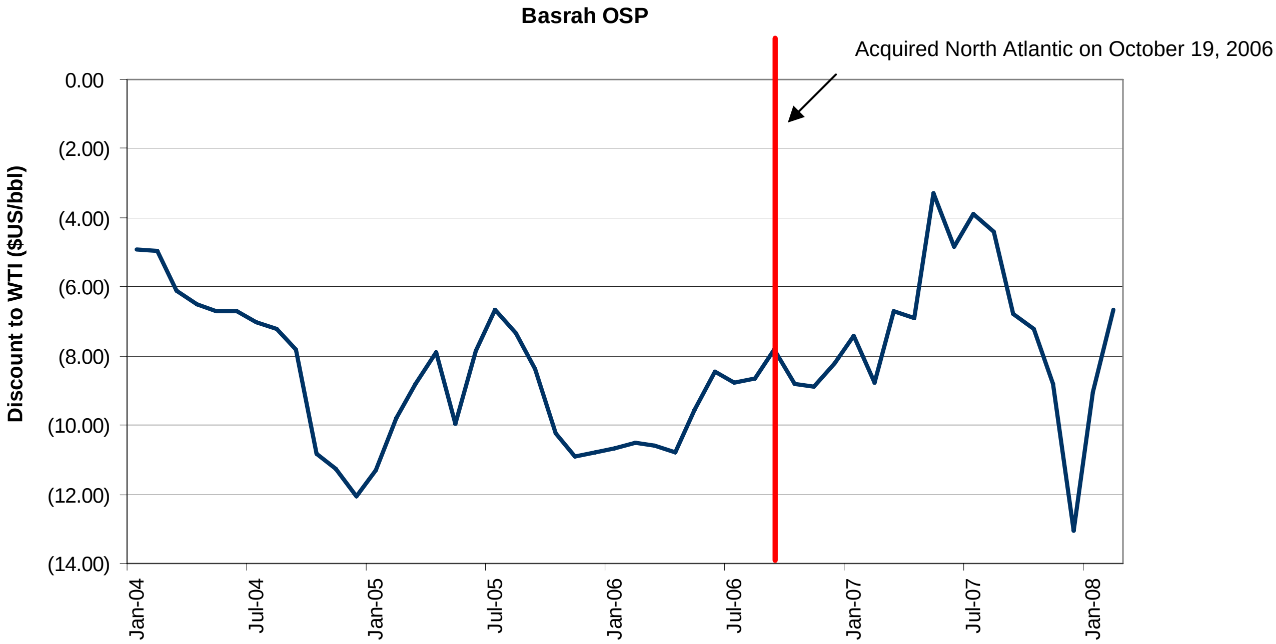
A comparison of crude oil and VGO feedstocks processed for each of the first six months and last six months of 2007 is presented below.

	Six Months Ended June 30, 2007			**Six Months Ended December 31, 2007**		
	Cost of Feedstock	**Volume**	**Cost per Barrel(1)**	**Cost of Feedstock**	**Volume**	**Cost per Barrel(1)**
	(000's of Cdn $)	(000s of bbls)	(US$/bbl)	(000's of Cdn $)	(000s of bbls)	(US$/bbl)
Basrah Light	**859,308**	**13,795**	**54.88**	**749,048**	**9,435**	**78.44**
Hamaca	**172,501**	**2,879**	**52.79**	**190,367**	**2,301**	**81.74**
Urals	**152,007**	**2,246**	**59.63**	**85,442**	**1,121**	**75.30**
Crude Oil Feedstock	**1,183,816**	**18,920**	**55.12**	**1,024,857**	**12,857**	**78.76**
Vacuum Gas Oil	**134,347**	**1,831**	**64.64**	**220,511**	**2,387**	**91.27**
	1,318,163	**20,751**	**55.96**	**1,245,368**	**15,244**	**80.72**
Other costs	**(277)**			**32,653**		
	1,317,886			**1,278,021**		

(1) Cost of feedstock includes all costs of transporting the crude oil to refinery in Newfoundland

During 2007, our feedstock was comprised of 87,061 bbl/d of medium sour crude oil, (approximately 73% Basrah Light crude from Iraq, 16% Hamaca crude from Venezula and 11% Urals from Russia) and 11,556 bbl/d of VGO as compared to 80,767 bbl/d of crude oil (approximately 91% Basrah Light and 9% Hamaca), and 6,123 bbl/d of VGO in the prior year. We prefer to process Basrah Light feedstock due to its expected lower cost as compared to Hamaca and Urals while yielding a similar refined product slate and quality. The lower daily throughput during the period of October 19, 2006 to December 31, 2006 was the result of a turnaround that extended from the date of our acquisition of North Atlantic through to December 1, 2006. Similarly in 2007, daily throughput averaged 98,617 bbl/d for the year as two back-to-back shutdowns in the fourth quarter reduced the annual throughput which had averaged 111,052 bbl/d through the first nine months of the year.

Changes to our cost of feedstock reflect numerous factors beyond changes in the WTI benchmark price as our refinery competes for international waterborne barrels and the WTI benchmark price generally reflects a land-locked North American price with limited access to the Gulf Coast. The discount of Basrah Light relative to the WTI benchmark price is influenced by the quality of the crude as well as by the economics of other purchasers who may not be North American based nor deal in US dollars. On a monthly basis, the Oil Marketing Company of the Republic of Iraq announces its Official Selling Price ("OSP") which is expressed in US dollars as a discount to the WTI benchmark price for North American deliveries and at the time of announcement, is equivalent to the discount to the Brent benchmark price in Euros for deliveries to Europe. Since our acquisition of North Atlantic in October 2006, the OSP has fluctuated from a low of US$3.30 in May 2007 to a high of US$13.05 in December 2007. The following graph summarizes the OSP for Basrah Light since January 2004 which relative to our US$10.05 average refining margin for 2007 demonstrates the significance of OSP pricing to our downstream performance:



Between the loading of the crude oil and its consumption, the OSP discount may change but for our load of Basrah Light, the OSP discount applicable at the time of loading does not change. For example, the OSP discount of US$6.90 in April 2007 was a component of the cost of our feedstock in June and July recognizing the 30 to 45 days to load in Iraq and ship to our refinery. While we are able to "operationally hedge" the WTI component of our feedstock costs between the date we commit to a purchase price and our processing of the crude, we are not able to effectively float the OSP component due to the lack of counterparty interest. As a result, the spike in the OSP discount in December 2007 to US$13.05 will significantly influence our refining margins in February and March 2008.

We also process Hamaca and Urals to complement our Basrah Light as a sufficient volume of Basrah Light is not always available and when other crudes are blended with Basrah Light, the blend may improve processing. During the first six months of 2007, we purchased Urals to ensure the refinery had ample crude oil feedstock and paid a premium as compared to Basrah Light. In July and August of 2007 when we processed the Urals, the WTI benchmark price was US$74.15 and US$72.36, respectively, which has resulted in our cost of Urals processed during the last six months of the year appearing to be lower than our cost of Basrah Light as the average WTI price for the last six months of 2007 of US$83.03 increased our cost of Basrah Light throughout the last half of the year. Typically, the price of Hamaca will closely track Basrah Light however the sharp increase in the OSP discount in late 2007 has resulted in the Hamaca crude becoming relatively more expensive.

In addition to VGO produced by our refinery, we purchase VGO as our Isomax unit's processing capacity exceeds the VGO provided by our refinery from feedstock. In addition, we purchased incremental VGO during the third quarter of 2007 as we stockpiled VGO for use by the Isomax unit during the shutdown of the crude unit and vacuum tower in the fourth quarter. During 2007, VGO comprised approximately 9% of our total feedstock during the first half of the year and approximately 16% of total feedstock for the last six months of the year. Typically, VGO trades at a US$3.00 to US$5.00 premium to WTI due to the limited amount of processing required to yield a substantial volume of gasoline and diesel. However in late 2007, the VGO market was disrupted due to a refinery outage in the US Gulf Coast and concurrently, a reduction in VGO exports from Europe which resulted in the tightly balanced VGO market temporarily falling out of balance and the VGO premium to WTI temporarily spiked for a few months.

The cost of our crude oil feedstock during 2007 averaged US$64.99 per barrel comprised of US$55.12 in the first six months of the year and US$78.76 during the last six months, while the WTI benchmark price averaged US$72.31 for the year reflecting US$61.60 during the first half of the year and US$83.03 during the last half. During the first half of 2007, our average crude oil feedstock cost was US$6.48 per barrel less than the WTI benchmark price whereas for the last six months, our crude oil feedstock costs were US$4.27 per barrel less than the WTI benchmark price, consistent with narrowing of the Basrah Light OSP discount during the year.

The price of VGO during 2007 averaged US$78.66 per barrel as compared to the WTI benchmark price of US$72.31, a premium of US$6.35 for the year and a premium during the first six months averaging US$3.04 and US$8.24 during the last six months of the year.

The average cost of our feedstock in 2007 was US$66.59 per barrel comprised of a US$5.64 discount to the WTI benchmark price in the first six months and a US$2.31 discount during the last six months of the year. The reduced average discount in the last half of the year reflects an increased consumption of premium priced VGO feedstock combined with the narrowing in the Basrah Light OSP.

Refining Gross Margin

Our refining gross margin for 2007 aggregated to $386.7 million being a combination of crack spreads from gasoline, distillates and high sulphur fuel oil comprised of $322.6 million earned in the first half of the year and $64.2 million in the last half. During the first six months of 2007, our gasoline and distillates crack spreads, relative to the WTI benchmark price, were US$20.75 and US$17.88 per barrel, respectively, aggregating to an average crack spread of US$19.32 per barrel as compared to the “2-1-1 Crack Spread” of US$17.29 for the same period. We would anticipate our average gasoline/distillate crack spread to be higher than the “2-1-1 Crack Spread” benchmark as our distillate sold at a US$0.10 per US gallon premium over the NYMEX heating oil benchmark during the first six months of 2007. During the first six months of 2007, our high sulphur fuel oil sold at a US$14.99 discount to the WTI benchmark price and our feedstock cost was US$5.64 per barrel lower than the WTI benchmark price.

During the last six months of 2007, our gasoline and distillates crack spreads, relative to the WTI benchmark price, were US$7.82 and US$14.78 per barrel, respectively, aggregating to an average crack spread of US$11.30 as compared to the “2-1-1 Crack Spread” of US$10.60 for the same period. As expected, our average gasoline/distillate crack spread was US$0.70 per barrel higher than the “2-1-1 Crack Spread” benchmark as our distillates sold at a premium over the respective NYMEX benchmark prices during this period but primarily due to the 10 day delay in pricing our refined products pursuant to the Supply and Offtake Agreement during a period when NYMEX gasoline and NYMEX heating oil price rose an average of 10% and 28%, respectively. During the last six months of 2007, our high sulphur fuel oil sold at a US$21.05 per barrel discount to the WTI benchmark price (a US$6.06 reduction in price as compared to the first six months of the year) and our feedstock cost was US$2.31 per barrel lower than the WTI benchmark price, an increase of US$3.33 per barrel in our feedstock costs relative to the WTI benchmark price.

During the first six months of 2007, robust refining margins combined with our refinery operating at near name plate capacity to generate $322.6 million of gross margin (US$13.69 per barrel of throughput) as compared to $64.2 million (US$4.16 per barrel of throughput) during the last six months of the year. The $258.4 million reduction in gross margin during the last six months of 2007 as compared to the first six months of the year is comprised of a $172.7 million variance attributed to reduced crack spreads and an $85.7 million unfavourable variance due to reduced throughput. Included in the reduced crack spreads is a $25.7 million unfavourable variance due to the strengthening of the Canadian dollar relative to the US dollar denominated crack spread pricing.

For the period from October 19, 2006 to December 31, 2006, our refining gross margin totaled $67.0 million comprised of $83.7 million from the sale of gasoline and distillate products refined from crude oil feedstock and $9.7 million from gasoline and distillate refined from VGO offset by a $26.4 million negative margin from the production of high sulphur fuel oil.

Operating Expenses

The following summarizes the operating costs from the refinery and marketing division for each of the first six months and last six months of 2007:

	Six Months Ended June 30, 2007			Six Months Ended December 31, 2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	**Refining**	**Marketing**	**Total**
Operating expense	**43,153**	**8,792**	**51,945**	**40,782**	**9,749**	**50,531**
Turnaround and catalyst	**-**	**-**	**-**	**34,486**	**-**	**34,486**
Purchased energy	**42,337**	**-**	**42,337**	**49,991**	**-**	**49,991**
	85,490	**8,792**	**94,282**	**125,259**	**9,749**	**135,008**

The largest component of our refining operating expense is wages and benefits which totaled $59.6 million during 2007 (2006 - $11.2 million) while the other significant components were maintenance and repairs costs of $14.6 million (2006 - $2.1 million), insurance of $7.0 million (2006 - $1.4 million) and professional services of $6.4 million (2006 - $0.8 million). During the year ended December 31, 2007 refining operating expenses were $2.33 per barrel as compared to $2.34 per barrel in the prior period consistent with our expectations of approximately $2.20 to $2.40 per barrel. The marketing division's operating costs run approximately $4.5 million per quarter aggregating to $18.5 million for 2007.

Turnaround and catalyst expenditures of $22.1 million and $12.4 million, respectively, were incurred during the two planned shutdowns in 2007. Catalyst expenditures include the planned biannual top-bed catalyst change-out on the hydrocracker unit and the replacement of the catalyst on the distillate hydrotreater unit. Turnaround expenditures include planned major maintenance completed simultaneously with the catalyst change-out on both the Isomax, and crude unit. The accelerated shutdown of the crude unit and vacuum tower, originally scheduled for the spring of 2008, contributed an incremental $17.0 million and $7.4 million to turnaround and catalyst expenditures, respectively.

Purchased energy, consisting of low sulphur fuel oil and electric power, is required to provide heat and power to refinery operations, respectively. Our purchased energy costs increased to $2.56 per barrel during 2007 as compared to $2.47 per barrel during 2006 as a result of the increased price of fuel oil.

Marketing Expense

During the year ended December 31, 2007 marketing expense, in conjunction with the Supply and Offtake Agreement, is comprised of $3.4 million of marketing fees (based on US $0.08 per barrel of feedstock) to acquire feedstock ($0.5 million in the period October 19, 2006 to December 31, 2006) and $31.6 million of "Time Value of Money" charges ($4.6 million in the period October 19, 2006 to December 31, 2006).

Capital Expenditures

Capital spending for the year ended December 31, 2007 totaled $44.1 million including $8.0 million for tank maintenance and recertification, $6.3 million to replace heat exchanger bundles, $4.8 million for re-piping of the crude unit and vacuum tower as well as approximately $2.0 million of an estimated $27 million to enhance our visbreaker capacity which is expected to be completed in the fourth quarter of 2008.

Depreciation and Amortization Expense

The following summarizes the depreciation and amortization expense for 2007 and 2006:

	Year Ended December 31, 2007			For the Period October 19, 2006 to December 31, 2006		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	**Refining**	**Marketing**	**Total**
Tangible assets	**64,251**	**2,071**	**66,322**	**13,833**	**410**	**14,243**
Intangible assets	**4,781**	**1,497**	**6,278**	**1,049**	**190**	**1,239**
	69,032	**3,568**	**72,600**	**14,882**	**600**	**15,482**

The process units are amortized over an average useful life of 20-30 years. The intangible assets, consisting of engineering drawings, customer lists and fuel supply contracts, are amortized over a period of 20 years, 10 years and the term of the expected cash flows, respectively.

Goodwill

On October 19, 2006, we recorded $203.9 million of goodwill with our acquisition of North Atlantic as the purchase price of the acquired business exceeded the fair value of the net identifiable assets and liabilities. As the refining assets are held in a self-sustaining subsidiary with a US dollar functional currency, the value of the goodwill is adjusted at the end of each accounting period to reflect the current US dollar exchange rate.

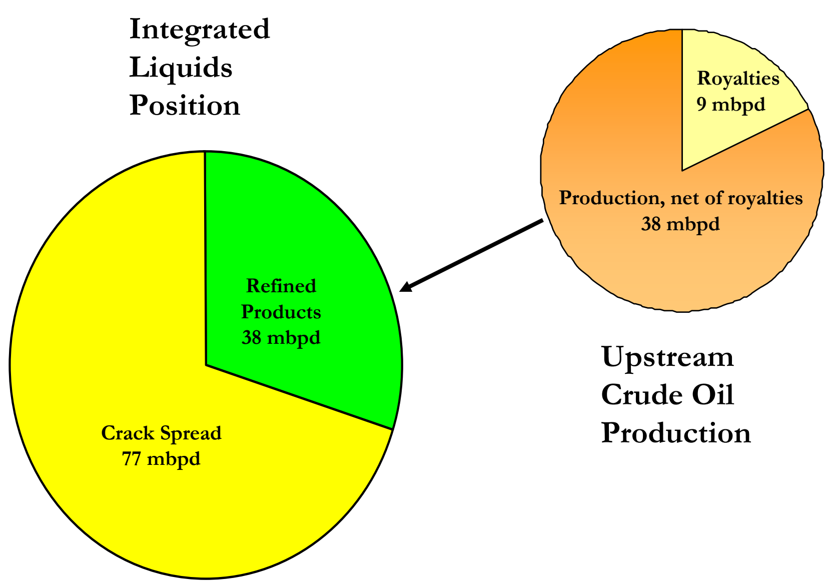
We assess goodwill for impairment annually, or more frequently if events or changes in circumstances warrant. We compare the fair value of our downstream assets and liabilities to their carrying value as well as evaluate the future cash flow projections of our downstream operations in light of the current outlook of the refining industry. Our assessment for the year ended December 31, 2007 concluded that the fair value of our downstream assets exceeds their carrying value and that future cash flows support the carrying value of the goodwill recorded in the accounts. For the year ended December 31, 2006, no charge for impairment was made.

RISK MANAGEMENT, FINANCING AND OTHER

Cash Flow Risk Management

Our cash flow risk management program includes a detailed analysis of the impact of changes in crude oil prices, natural gas prices, the US/Canadian dollar exchange rate and subsequent to acquiring the downstream operation in late 2006, certain refined product prices. While we anticipate our upstream operations will produce approximately 47,000 bbl/d of crude oil and 93,000 mcf/d of natural gas in 2008, our cash flow at risk is determined after deducting the royaltyholders' interest of approximately 9,000 bbl/d and 16,000 mcf/d, respectively. The crude oil produced by our upstream operations in western Canada does not physically flow to our refinery in the Province of Newfoundland and Labrador but for purposes of our cash flow at risk model, our cash flow from producing crude oil is financially integrated with our requirement to purchase crude oil feedstock for our downstream operations. As a result, our 2008 cash flow at risk is comprised of approximately 38,000 bbl/d of refined product prices and 77,000 bbl/d of refined product crack spreads as well as 77,000 mcf/d of western Canadian natural gas prices. Our refined product crack spread is the difference between the cost of our crude oil feedstock and the sales value of our refined products. Using forecast prices for 2008, our cash flow at risk model projects 2008 net revenues will be comprised of 66% refined product revenues, 21% refined product crack spreads and 13% western Canadian natural gas prices. Prior to acquiring the downstream operations, our cash flow at risk was limited to western Canadian crude oil prices and natural gas prices as well as the US/Canadian dollar exchange rate.

2008 Integrated Liquids Position:



We enter into pricing contracts with financial counterparties for periods of up to two years whereby we receive a predetermined price as per the contract and the counterparty receives a market price over the term of the contract. Commencing in 2006, we have limited our counterparties to lenders in our syndicated credit facility as the security provided under our credit agreement extends to our pricing contracts. This eliminates the requirement for margin calls and the pledging of collateral as well as enables the negotiation of a more limited number of events of default, all of which contribute to ensuring the contracts are in place for the contracted term and limit the potential for these contracts to exacerbate credit concerns. Typically, a significant mark-to-market deficiency in pricing contracts will heighten the counterparty's credit concerns; however, when the counterparty also participates in a related credit facility, the same commodity price increase giving rise to the mark-to-market credit concern should also provide offsetting credit comfort with respect to the credit facility as an increase in commodity prices should result in an appreciation in the value of the underlying assets securing the credit facility.

Prior to 2007, our pricing contracts were limited to WTI prices as publicly traded on the New York Merchantile Exchange ("NYMEX") and AECO natural gas prices as reported on the industry trading exchange. Commencing in 2007, the pricing terms of our refined product price contracts were limited to publicly traded benchmark prices on either the NYMEX or the Platts Index. By limiting the price basis to publicly traded benchmark prices, our price contracts should be sufficiently liquid as to enable an efficient unwinding of contracted positions should we encounter a disruption in production. Our execution of a refined product price contract combines the price protection of both the crude oil price (the "WTI" benchmark price) as well as the related refined product crack spread (either RBOB gasoline, heating oil or #6 fuel oil). The use of refined product price contracts consolidates credit requirements and results in a combining of the volatility of the WTI benchmark price with the volatility of the crack spread for refined product. In 2007, we have used a combination of "price collars" which provides a fixed floor price and price cap as well as a "three way" structure which provides a floor price with a premium over market price on the downside and a price cap. In the future, we may also use "fixed price swap" contracts which provide a "fixed price" and/or "participating swap" contracts which provide a firm floor price with a percentage participation in prices above the floor price. Details of our commodity price contracts outstanding at December 31, 2007 are included in Note 19 of our consolidated financial statements filed on SEDAR at www.sedar.com.

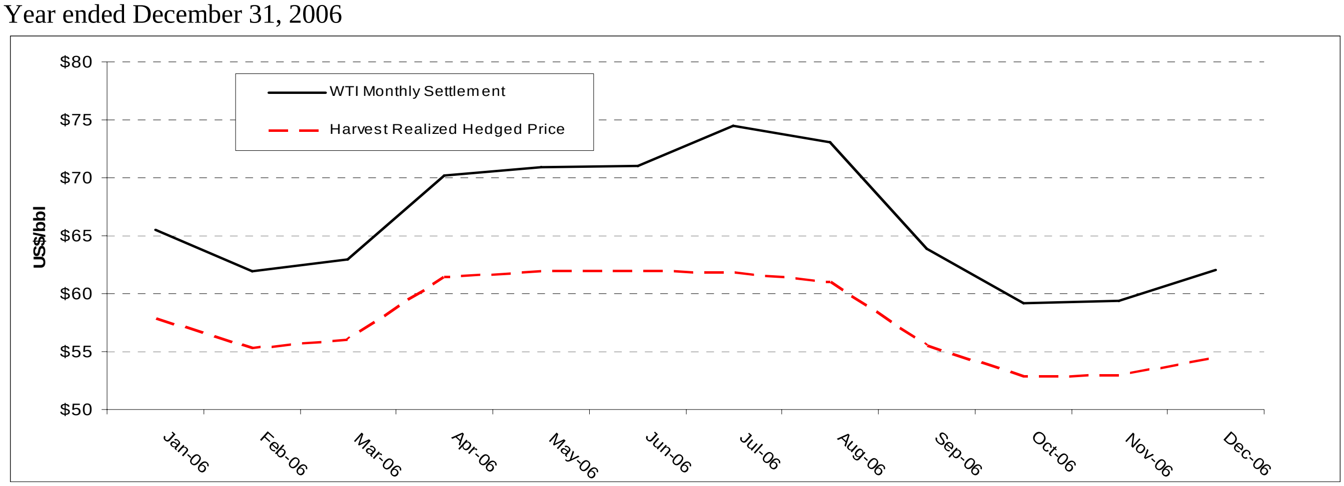
The table below provides a summary of the net gains and losses realized on our price risk management contracts for each of the years ended December 31, 2007 and 2006:

(in 000s)	Crude Oil	Natural Gas	Currency Exchange Rates	Electric Power	Total
Year ended December 31, 2007	$ (41,462)	$ 6,299	$ 5,725	$ 3,147	$ (26,291)
Year ended December 31, 2006	$ (80,832)	$ 4,838	$ 1,801[(1)]	$ 11,574	$ (62,619)

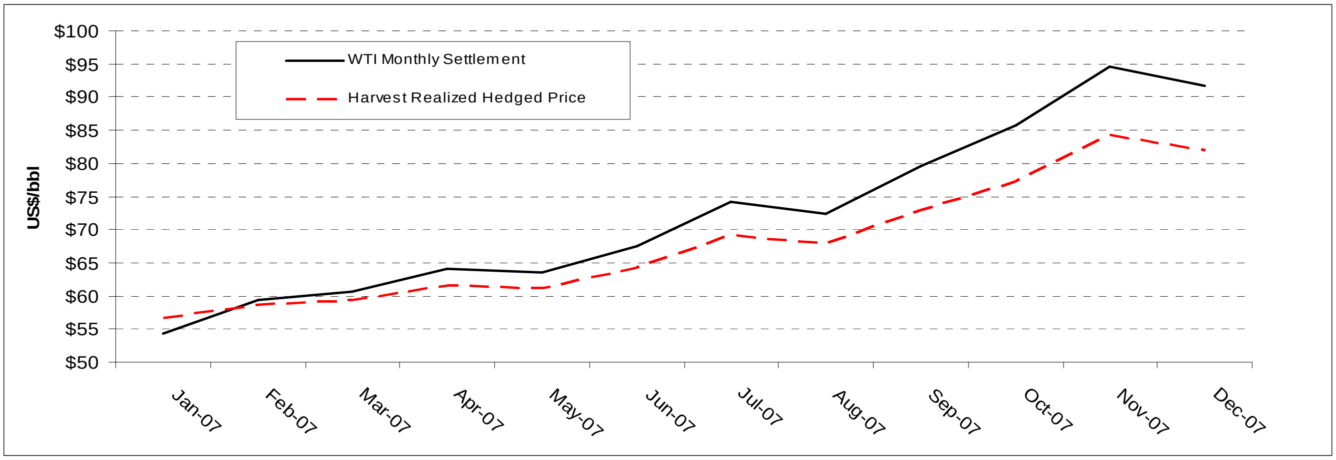
(1) Excludes $17.8 million realized on the series of US dollar forward purchase contracts entered into with respect to the purchase of North Atlantic.

During 2007, the net realized loss on price risk management contracts totaled $26.3 million, a $36.3 million reduction from the prior year substantially all related to our crude oil price contracts. The principal difference in our crude oil price contracts was the increase in the floor price to US$57.18 per bbl plus 70% participation on prices above US$57.18 in 2007 as compared to a floor price of US$43.80 plus 60% participation on prices above US$43.80 in 2006. With the average WTI price increasing US$6.07 from US$66.24 in 2006 to US$72.31 in 2007, the US$13.38 increase in our contracted floor price as well as the 10% higher participation level on prices in excess of the contracted floor price combined to reduce the losses realized on our crude oil contracts by $39.4 million in 2007 as compared to the prior year. The volume hedged averaged 23,750 bbl/d in 2006 and 27,500 bbl/d in 2007 which represented approximately 66% and 76% of our net production, respectively. The following charts present the average monthly WTI prices and the contracted crude oil price settlement in our oil pricing contracts for each of 2006 and 2007:

Year ended December 31, 2006



Year ended December 31, 2007



Typically, we enter into natural gas price contracts that provide a firm floor price in exchange for a price cap for the contract year (April through March of the following year) in anticipation of soft prices during the summer months. In 2007, we received $6.3 million primarily from our contracting for natural gas price protection on 30,000 GJ/d at a floor price equal to the greater of $7.00 per GJ or market price plus $2.00 for the period from April 2007 through March 2008 of which $5.5 million was received when we unwound the position in July 2007. In 2006, we had "price collar" contracts in place that provided floor prices on 25,000 GJ/d at $5.00 per GJ and with respect to a further 25,000 GJ/d, $7.00 per GJ. Substantially all of the $4.8 million gain in 2006 related to the natural gas price contract with the $7.00 floor price.

In 2007, the $5.7 million gain realized on our currency exchange rate contracts reflect the significant strengthening of the Canadian dollar relative to the US dollar from Cdn$1.1654 per US dollar at January 1, 2007 to Cdn$0.9913 on December 31, 2007. During 2007, we had US$8.7 million per month contracted at an exchange rate of Cdn$1.1228 per US dollar for the entire year which generated substantially all of the $5.7 million benefit while a further US$10 million contracted with a collar of Cdn$1.0000 and Cdn$1.0550 per US dollar added limited benefit. In addition, see the Currency Exchange discussion in this MD&A.

We also enter into fixed price electric power contracts to provide protection from rising power prices in Alberta. In 2007, Alberta's electric power prices averaged $66.84 per megawatt hour as compared to $80.48 in 2006. Relative to our $11.6 million gain realized in 2006, the $3.1 million benefit received in the current year from our fixed price electric power contracts reflects generally lower prices as well as an increase in the contracted fixed price from $51.48 per MWh in 2006 to $56.69 in 2007. Typically, our fixed price electric power contracts represent approximately 50% of our anticipated electrical power consumption and for 2008, we have fixed price contracts for 35 MWh for the period from January 2008 through December 2008 at a price of $56.69.

During 2007, we entered into the following refined product price contracts:

For the period from January 2008 through December 2008

- 12,000 bbl/d of NYMEX heating oil,
- 8,000 bbl/d of Platts heavy fuel oil,
- 6,000 bbl/d of NYMEX heating oil crack spread, and
- 2,000 bbl/d of Platts heavy fuel oil crack spread.

For the period from July 2008 through December 2008

- 6,000 bbl/d of NYMEX RBOB gasoline comprised of an RBOB crack contract and a WTI price contract.

For the period from January 2009 through June 2009

- 12,000 bbl/d of NYMEX heating oil, and
- 8,000 bbl/d of Platts heavy fuel oil.

In addition, we have contracted for 10,000 bbl/d of WTI prices for the first half of 2008 with an average floor price of US$60.00 and participation in 73% of the upside above US$60.00 which was placed prior to our acquisition of the downstream business. In respect of our refined product price and WTI price exposures, these contracts represent approximately 79% of our exposure for the first half of 2008, 68% for the second half of 2008 and 53% for the first half of 2009. With respect to our cash flow exposure related to refined product crack spreads, our contracts represent approximately 10% of our crack spread exposure for 2008.

The table below provides a summary of net unrealized gains and losses recorded for our price risk management contracts for each of the years ended December 31, 2007 and 2006 which reflects the change in period end unrealized gains and losses:

(in 000s)	Crude Oil	Refined Products	Natural Gas	Currency Exchange Rates	Electric Power	Total
Year ended December 31, 2007	$ (14,601)	$ (138,801)	$ (596)	$ 13,904	$ (7,687)	$ (147,781)
Year ended December 31, 2006	$ 53,820	-	$ (662)	$ (5,309)	$ 3,932	$ 51,781

At the end of 2007, the mark-to-market deficiency on our refined product and WTI price contracts was $138.8 million and $24.9 million, respectively, while the mark-to-market value of our natural gas, currency exchange rate and electrical power price contracts aggregated to $14.0 million. Our 2008 refined product contracts were placed in mid-2007 when the WTI benchmark price was approximately US$71.00 and the NYMEX price of heating oil and Platts Index for fuel oil were approximately US$2.00 per gallon and US$55.00 per barrel, respectively, as compared to the 2007 year end closing prices of US$95.98 for WTI, US$2.64 per gallon for NYMEX heating oil and US$75.15 per barrel for Platts fuel oil. While our contracted prices for 2008 are higher than prices received in 2007, the 2007 year end prices for WTI and refined products were higher still which has resulted in the significant mark-to-market deficiency. At the end of 2007, we had a modest 276 GJ/d of natural gas price contracts in place through December 2008.

While modest compared to our refined product position, we have contracted a fixed exchange rate on US$8.3 million per month for the period from January 2008 through June 2008 averaging Cdn$1.11 per US$1.00 and collared an exchange rate of Cdn$1.00 to Cdn$1.055 on a further US$10 million per month covering January 2008 through December 2008. These contracts had a mark-to-market value of $8.6 million at the end of 2007. For 2008, approximately 52% of our Alberta power consumption is fix priced at $56.69 and mark-to-market value of this contract was $5.6 million at the end of 2007.

Interest Expense

(000s)	2007	2006	Change
	Year Ended December 31		
Interest on short term debt			
Bank loan	**$ 1,275**	$ 1,489	(14%)
Convertible Debentures	**2,498**	-	100%
Amortization of deferred finance charges – short term debt	**1,811**	3,375	(46%)
	5,584	4,864	15%
Interest on long-term debt			
Bank loan	**70,204**	30,967	127%
Convertible Debentures	**56,740**	20,229	180%
$7^{7/8}$% Senior Notes	**22,561**	22,624	-%
Amortization of deferred finance charges – long term debt	**2,696**	5,073	(47%)
	152,201	78,893	93%
Total interest expense	**$ 157,785**	$ 83,757	88%

Interest expense, which includes the amortization of related financing costs, was $74.0 million higher in 2007 than the prior year. Of this increase, $39.0 million is attributed to increased short and long term bank loan interest resulting from the significant increase in bank debt to finance the acquisitions of North Atlantic in October 2006 and to a lesser extent, Grand in August 2007. An additional $39.0 million of interest expense was incurred in 2007 compared to 2006 due to the increased principal amount of Convertible Debentures outstanding, offset by a $3.9 million reduction in the amortization charge for deferred financing costs.

At December 31, 2007, we had drawn approximately $1,279.5 million of bank borrowings as compared to $1,595.7 million at December 31, 2006. During the First Quarter of 2007, our bank borrowings were reduced with the net proceeds of $357.4 million from our issuance of 6,146,750 Trust Units and $230 million principal amount of 7.25% Debentures due 2014. During the Second Quarter of 2007, our bank borrowings were reduced by a combination of net proceeds of $218.5 million from our issuance of 7,302,500 Trust Units and surplus cash from operating activities after capital spending and distribution requirements. In the Third Quarter of 2007, we increased our bank borrowings by $157.0 million, of which $139.3 million is attributed to the acquisition of Grand during the quarter. Our bank borrowings were further increased by $74.4 million in the Fourth Quarter, as our cash distributions and capital spending exceeded our cash flow from operating activities by $61.1 million. Currently, the interest on our Three Year Extendible Revolving Facility is at a floating rate based on 70 basis points over bankers' acceptances for Canadian dollar borrowings and 70 basis points over the London Inter Bank Order Rate for US dollar borrowings. During the year ended December 31, 2007, our interest charges on bank loans aggregated to $71.6 million, reflecting effective interest rates of 5.28% and 6.08% for the Canadian and U.S. amounts drawn, respectively. Further details on our credit facilities are included under "Liquidity and Capital Resources".

The interest on our Convertible Debentures totaled $59.2 million during the year ended December 31, 2007, and is based on the effective yield of the debt component of the Convertible Debentures. Details on the Convertible Debentures outstanding are fully described in Note 12 to the audited consolidated financial statements for the year ended December 31, 2007 filed on SEDAR at www.sedar.com. During the year ended December 31, 2007, there were $161.1 million of principal amount Convertible Debentures converted to 5,922,708 Trust Units.

The interest on our $7^{7/8}$% Senior Notes totaled $22.6 million for the year ended December 31, 2007. Like our Convertible Debentures, interest expense is based on the effective yield, and as a result, the interest expense recorded is greater than the cash interest paid. Due to the recent strength of the Canadian dollar relative to the U.S. dollar, our cash interest expense has been lowered as interest on these notes is paid in U.S. dollars, however our non-cash interest expense has increased due to the adoption of the revised standard on financial instruments. See Note 3 of the consolidated financial statements for the year ended December 31, 2007 filed on SEDAR at www.sedar.com.

Included in short and long term interest expense is the amortization of the discount on the $7^{7/8}$% Senior Notes, the accretion on the debt component balance of the Convertible Debentures to face value at maturity, as well as the amortization of commitment fees and legal costs incurred for our credit and bridge facilities, all totaling $4.5 million for the year ended December 31, 2007.

Currency Exchange

Currency exchange gains and losses are attributed to the changes in the value of the Canadian dollar relative to the U.S. dollar on our U.S. dollar denominated LIBOR bank loans, $7^{7/8}$% Senior Notes as well as any other U.S. dollar cash balances. Since December 31, 2006, the Canadian dollar has strengthened significantly compared to the U.S dollar. As a result we have earned an unrealized foreign exchange gain on our $7^{7/8}$% Senior Notes of $42.3 million during the year ended December 31, 2007. In the Third Quarter of 2007, we repaid our U.S. dollar denominated LIBOR bank loans that were incurred in connection with our purchase of North Atlantic, realizing a foreign exchange gain of $43.5 million in the quarter and $47.1 million year-to-date in respect of this loan. In addition, during the year ended December 31, 2007 we also incurred unrealized foreign exchange losses and realized foreign exchange gains on North Atlantic transactions of $10.6 million and $4.7 million, respectively.

Our downstream operations are considered a self-sustaining operation with a U.S. dollar functional currency. The foreign exchange gains and losses incurred by our downstream operations relate to Canadian dollar transactions converted to U.S. dollars as their functional currency is U.S. dollars. The cumulative translation adjustment recognized in other comprehensive income represents the translation of our downstream operation's U.S. dollar functional currency financial statements to Canadian dollars using the current rate method. In 2007, the strengthening of the Canadian dollar relative to the U.S. dollar resulted in a $243.6 million cumulative translation loss as the stronger Canadian dollar results in a decrease in the relative value of our downstream net assets.

Future Income Tax

During 2007, there were two significant Canadian income tax changes that impacted our accounting for future income taxes. On June 22, 2007, Bill C-52 became law and on December 14, 2007, Bill C-28 became law. Bill C-52 contains provisions to implement the proposals to tax publicly traded income trusts and as a result, we recorded a $255.0 million future income tax charge during the second quarter of 2007 to apply an expected tax rate to the temporary differences between the book value and the tax basis of our assets held by our mutual fund trust and other "flow through" vehicles as forecasted on the effective date of the tax change, January 1, 2011. Concurrent with the recording of this non-cash future income tax expense, we also recorded an offsetting future income tax asset of $77.3 million to reflect the application of the current and expected future tax rates to the temporary differences between the book value and the tax basis of assets held by our corporate entities on June 30, 2007 which had not been previously reflected due to the lack of assurance that the benefit of this tax asset would be realized.

Bill C-28 contains the provisions to implement reductions in the federal corporate income tax rates. The federal corporate income tax rate will be reduced from 20.5% to 19.5% in 2008 with further reductions scheduled resulting in a 15% tax rate as of January 1, 2012. These rate reductions also apply to the expected tax rate applicable to our mutual fund trust and other "flow through" vehicles. Accordingly, in the fourth quarter of 2007, we adjusted our future income tax provision to reflect these reduced tax rates.

As at the end of 2007, we have a net future income tax provision on our balance sheet totaling $86.6 million comprised of a $270.5 million provision for our mutual fund trust and other "flow through" entities and a net asset of $183.9 million for our corporate entities. The net provision for our mutual fund trust and other "flow through" entities will be reviewed for changes in our forecasted temporary differences and legislative tax rate changes both as of January 1, 2011. The future income tax asset recorded by our corporate entities will fluctuate during each accounting period to reflect changes in the respective temporary differences between the book value and tax basis of their assets as well as further legislative tax rate changes.

Currently, the principal source of our corporate entities' temporary differences is the difference between our net book value of our property, plant and equipment versus our unclaimed tax pools and the recognition for accounting purposes of a mark-to-market deficiency on our risk management contracts. Future income tax recoveries from of our corporate entities may fully offset the future income tax provision of our mutual fund trust and other "flow through" entities prior to 2011.

In our current structure, payments in respect of net profits interests and interest on inter-entity debt are made between our operating entities and our mutual fund trust which ultimately transfers both taxable income and the income tax liability to the holders of our Trust Units. As a result, no cash income taxes have been paid by Harvest, However, effective January 1, 2011, Harvest will become subject to the provisions of Bill C-52 should Harvest remain in its current structure. At the end of 2007, we estimate our tax pools to be as follows:

Tax Classification (in millions)	Trust	Upstream Operations	Downstream Operations	Total
Canadian Oil & Gas Property Expenditures	$ 550	$ 310	$ -	$ 860
Canadian Development Expenditures	-	230	-	230
Unclaimed Capital Costs	-	500	420	920
Non-capital losses and other	40	570	150	760
Total	$ 590	$ 1,610	$ 570	$ 2,770

Contractual Obligations and Commitments

We have contractual obligations and commitments entered into in the normal course of operations including purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, and land lease obligations. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. We also have contractual obligations and commitments that are of a less routine nature as disclosed in the following table:

		Maturity			
Annual Contractual Obligations *(000s)*	**Total**	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt(2)	**1,527,326**	-	1,279,501	247,825	-
Interest on long-term debt(4)	**233,881**	88,216	130,319	15,346	-
Interest on Convertible Debentures(3)	**252,454**	46,832	92,916	86,063	26,643
Operating and premise leases	**27,362**	7,572	12,397	7,145	248
Purchase commitments(5)	**17,224**	15,924	1,300	-	-
Asset retirement obligations(6)	**1,002,893**	24,617	17,350	27,437	933,489
Transportation (7)	**6,110**	2,249	2,953	861	47
Pension contributions	**31,360**	1,143	3,631	5,301	21,285
Feedstock commitments	**843,583**	843,583	-	-	-
Total	**3,942,193**	1,030,136	1,540,367	389,978	981,712

(1) As at December 31, 2007, we had entered into physical and financial contracts for production with average deliveries of approximately 8,000 bbl/d for 2008. We have also entered into financial contracts for our downstream production of refined products with average deliveries of approximately 34,000 bbl/d in 2008 and 10,000 bbl/d in 2009. We have also entered into financial contracts to minimize our exposure to fluctuating electricity prices. Please see Note 18 to the consolidated financial statements for further details.
(2) Assumes that the outstanding Convertible Debentures either convert at the holders' option or are redeemed for Units at our option.
(3) Assumes no conversions and redemption by Harvest for Trust Units at the end of the second redemption period. Only cash commitments are presented.
(4) Assumes constant foreign exchange rate.
(5) Relates to drilling commitments, AFE commitments and downstream purchase commitments.
(6) Represents the undiscounted obligation by period
(7) Relates to firm transportation commitment on the Nova pipeline.

We have a number of operating leases in place on moveable field equipment, vehicles and office space and our commitments under those leases are noted in our annual contractual obligations table above. The leases require periodic lease payments and are recorded as either operating costs or G&A. We also finance our annual insurance premiums, whereby a portion of the annual premium is deferred and paid monthly over the balance of the term.

Off Balance Sheet Arrangements

As at December 31, 2007, we have no off balance sheet arrangements in place.

Related Party Transactions

During the year ended December 31, 2007, Vitol Refining S.A. purchased U.S. $388.8 million of Basrah Light crude oil pursuant to the terms and conditions of the Supply and Offtake Agreement from a company in which a director of Harvest holds a minority equity interest. As at December 31, 2007, no amount related to these purchases is included in Harvest's accounts payable and accrued liabilities, and $68.0 million is included in the total feedstock commitments disclosed at the end of December 2007. Subsequent to December 31, 2007, no further commitments have been incurred relating to crude oil purchases by Vitol Refining S.A from this private company.

CHANGE IN ACCOUNTING POLICIES

Effective January 1, 2007, we have retrospectively without restatement adopted the new accounting standards of the Canadian Institute of Chartered Accountants respecting, "Financial Instruments – Recognition and Measurement"; "Comprehensive Income"; and "Financial Instruments – Disclosure and Presentation". The impact of adopting these new standards is reflected in our financial results for the year ended December 31, 2007 while the prior year comparative financial statements have not been restated. While the new standards change how we account for financial instruments, there were no material impacts on our results for the year ended December 31, 2007, with the most significant difference being that certain deferred charges previously presented as an asset are now netted against the respective debt and amortized to income using an effective interest rate. For a description of the new accounting standards and the impact on our financial statements of adopting such standards see Note 3 to the consolidated financial statements for the year ended December 31, 2007.

LIQUIDITY AND CAPITAL RESOURCES

During 2007, cash flow from operating activities was $641.3 million, including a reduction of $17.4 million in respect of non-cash working capital with the significant components of this being a $39.9 million reduction in accounts payable and a $34.5 million increase in downstream inventories offset by a $51.5 million reduction in accounts receivable. Cash flow from operating activities before changes in non-cash working capital totaled $658.7 million. We declared distributions of $610.3 million, required $344.8 million for capital expenditures and raised $178.5 million with our distribution re-investment plans. The net cash requirement of $135.3 million was funded with bank borrowings.

During the year, our net bank borrowings decreased by $316.2 million primarily from the $576.0 million of net proceeds from the issuance of $230.0 million of principal amount of Convertible Debentures and 13,499,250 Trust Units offset by the $135.3 million required for our capital expenditure program and $138.2 million for our property acquisition and disposition activity. Our upstream acquisition and disposition activity required funding as the $60.6 million of net proceeds we realized from the disposition of 885,000 barrels of proved reserves (at an average of $68.47 per boe) were more than offset by our investment of $198.7 million in an additional 7,283,000 barrels of proved reserves, including the acquisition of Grand Petroleum Inc., at an average cost of $27.29 per boe.

During the fourth quarter of 2007, cash flow from operating activities was $88.0 million, including $16.6 million in respect of a reduction in non-cash working capital with the more significant components being a $26.9 million reduction in accounts payable offset by a $29.9 million reduction in accounts receivable and a $6.1 million reduction in downstream inventories. Cash flow from operating activities before changes in non-cash working capital totaled $71.4 million. We declared distributions of $144.7 million, required $47.5 million for capital expenditures and raised $43.1 million with in our distribution re-investment plans. The net cash requirement of $61.1 million was funded by an increase in bank borrowings.

For the year ended December 31, 2006, cash flow from operating activities was $507.9 million, including a $28.2 million reduction in respect of non-cash working capital with the more significant components being a $55.5 million increase in accounts receivable offset by a $17.9 million increase in accounts payable and a $6.0 million increase in distributions payable. Cash flow from operating activities before changes in non-cash working capital totaled $536.0 million. We declared distributions of $468.8 million, required $398.3 million for capital expenditures and received $167.5 million from participation in our distribution re-investment plans. The net cash requirement of $191.7 million was funded with bank borrowings.

At the end of 2007, we had $320.5 million of unutilized borrowing capacity from our $1.6 billion Three Year Extendible Revolving Credit Facility as compared to $94.0 million of unutilized capacity under a $1.4 billion credit facility at the beginning of the year. In April 2007, we increased this facility from $1.4 billion to $1.6 billion and with the exception of $65 million of lending commitments which retained a March 2009 maturity date, extended the maturity date of our Three Year Extendible Revolving Credit Facility to April 2010. In October 2007, we re-assigned the $65 million of non-extending lender commitments to other lenders in our banking syndicate and concurrently extended the maturity date on this incremental commitment to April 2010. In late 2007, the much publicized sub-prime mortgage/asset backed commercial paper crisis had resulted in a tightening of credit availability and a general re-pricing of credit. As we do not generally maintain any surplus cash, we have no direct exposure to asset backed commercial paper. As the disruptions in the capital markets continue, we are comfortable with the April 2010 maturity date for our credit facilities and may elect to defer extending the maturity date until capital market conditions improve.

Our cash flow risk management program includes our entering into numerous pricing contracts. We have limited our counterparties to the lenders in our syndicated credit facilities as the security provided in our credit agreement extends to our pricing contracts and this eliminates the requirement for margin calls and the pledging of collateral as well as limits the negotiation of events of default, all of which contribute to ensuring that these contracts improve our liquidity rather than exacerbate credit concerns.

The following table summarizes our capital structure for each of the years ended December 31, 2007 and 2006:

	As At December 31	
(in millions)	**2007**	2006
DEBT		
Credit Facilities		
- Three Year Extendible Revolving Credit Facility	**$1,279.5**	$1,306.0
- Senior Secured Bridge Facility	-	289.7
Total Bank Debt	**1,279.5**	1,595.7
7 7/8 % Senior Notes Due 2011 (US$250 million)[1]	**247.8**	291.4
Convertible Debentures, at principal amount		
10.5% Debentures Due 2008	**24.3**	26.6
9% Debentures Due 2009	**1.0**	1.2
8% Debentures Due 2009	**1.7**	2.2
6.5% Debentures Due 2010	**37.1**	37.9
6.4% Debentures Due 2012	**174.6**	174.8
7.25% Debentures Due 2013	**379.3**	379.5
7.25% Debentures Due 2014	**73.2**	-
Total Convertible Debentures	**691.2**	622.2
Total Debt	**2,218.5**	2,509.3
TRUST UNITS		
148,291,170 issued at December 31, 2007	**3,736.1**	
122,096,172 issued at December 31, 2006		3,046.9
TOTAL OF DEBT AND TRUST UNITS	**$5,954.6**	$5,556.2

(1) Face value converted at the period end exchange rate.

During 2007, the significant changes to our capital structure were:

- Issuance of $230 million principal amount of 7.25% Debentures Due 2014 and 6,146,750 Trust Units in February with net proceeds of $357.4 million used to repay the Senior Secured Bridge Facility and reduced borrowings on our Three Year Extendible Revolving Credit Facility by $67.7 million,
- Extension of our Three Year Extendible Revolving Credit Facility's maturity date to April 2010 and a $200 million increase in the aggregate commitment to $1.6 billion,
- Issuance of a further 7,302,500 Trust Units in June to reduce borrowings on our Three Year Extendible Revolving Credit Facility by $218.5 million,
- Issuance of 5,922,708 Trust Units on the conversion of $161.1 million of principal amount of Convertible Debentures, and
- Issuance of 6,809,987 Trust Units pursuant to Harvest's Premium Distribution™, Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "DRIP Plans") raising $178.5 million.

Concurrent with the closing of the Plan of Arrangement with Viking on February 3, 2006, we entered into a covenant-based Three Year Extendible Revolving Credit Agreement and have amended this agreement to extend the maturity to April 2010 and upsized the facility from an initial $750 million commitment to $1.6 billion. This facility is secured by a $2.5 billion first floating charge over all of our assets and generally contains typical covenants with the most restrictive being an aggregate limitation of $25 million on financial assistance and/or capital contributions to parties other than those included in the first floating charge debenture, a limitation to carrying on business in countries that are not members of the Organization of Economic Co-operation and Development and limitations on payments of distributions in certain circumstances such as an event of default. The credit facility contains floating interest rates that are expected to range between 65 and 115 basis points over bankers' acceptance rates (currently 70 bps) depending on the ratio of our secured senior debt (excluding $7^{7/8}$% Senior Notes and Convertible Debentures) to earnings before interest, taxes, depletion, amortization and other non-cash amounts ("EBITDA") with availability under this facility subject to:

Secured senior debt to EBITDA	3.0 to 1.0 or less
Total Debt to EBITDA	3.5 to 1.0 or less
Secured senior debt to capitalization	50% or less
Total Debt to capitalization	55% or less

At December 31, 2007, our Bank Debt to annualized EBITDA was 1.5 to 1.0, Total Debt (excluding Convertible Debentures) to annualized EBITDA was 1.8 to 1.0, while the Bank Debt to Total Capitalization was 29% and Total Debt to Total Capitalization was 34%. For a complete description of our covenant-based credit agreement, see Note 11 to our audited consolidated financial statements for the year ended December 31, 2007 filed on SEDAR at www.sedar.com.

In October 2004, Harvest Operations Corp., a wholly-owned subsidiary of Harvest, issued US$250 million of principal amount $7^{7/8}$% Senior Notes for net proceeds of $312.0 million Canadian dollars. These $7^{7/8}$% Senior Notes are unsecured, require semi-annual payments of interest and provide for the following permitted redemptions:

Beginning on October 15, 2007 at 103.938% of the principal amount (1);
After October 15, 2007 at 103.938% of the principal amount;
After October 15, 2009 at 101.969% of the principal amount; and,
After October 15, 2010 at 100% of the principal amount.

(1)Only permitted if necessary to prevent the Trust from being disqualified as a mutual fund trust for purposes of the Income Tax Act (Canada). Limited to 30% of the notes issued or less; otherwise 100% of the notes issued.

These $7^{7/8}$% Senior Notes contain certain covenants restricting, among other things, the sale of assets and the incurrence of additional indebtedness if such issuance would result in an interest coverage ratio, as defined, of less than 2.5 to 1.0 and our secured indebtedness to an amount less than 65% of the present value of future net revenues from our proved petroleum and natural gas reserves discounted at an annual rate of 10%. At the end 2007, 65% of the present value of the future net revenues from our proved petroleum and natural gas reserves discounted at an annual rate of 10% is approximately $1.86 billion.

At the end of 2007, we had $691.2 million of principal amount of Convertible Debentures issued in seven series with $64.0 million of principal amount due prior to 2012 and $627.2 million of principal amount due beyond 2011. Prior to maturity, these Convertible Debentures are convertible into Trust Units of Harvest, at the option of the holder, at the conversion price per Trust Unit specified for each series and may be redeemed at our option at a price equal to $1,050 per debenture during the first redemption period and $1,025 per debenture during a second redemption period. At maturity or upon redemption, the principal repayment obligation may be settled in the form of Trust Units at a price equal to 95% of the weighted average trading price for the preceding 20 consecutive trading days five days prior to the settlement. On January 31, 2008, we settled the maturity of $24.3 million principal amount of the 10.5% Convertible Debentures with the issuance of 1,116,593 Trust Units rather than settling the obligation with cash. The most restrictive term of the Convertible Debentures limits the issuance of additional Convertible Debentures if the principal amount of all issued and outstanding Convertible Debentures immediately after the issuance exceed 25% of the total market capitalization, being an aggregate of the principal amount of all issued and outstanding Convertible Debentures plus an amount equal to the current market price of all of the issued and outstanding Trust Units. At December 31, 2007, we would be limited to an additional issuance of Convertible Debentures of approximately $325 million.

Concurrent with the closing of the North Atlantic acquisition, North Atlantic entered into a Supply and Offtake Agreement with Vitol Refining S.A. ("Vitol"), a third party related to the vendor of North Atlantic. The agreement provides for ownership of substantially all of the crude oil feedstock and refined product inventory at the refinery be retained by Vitol and that Vitol be granted the right and obligation to provide and deliver crude oil feedstock to the refinery as well as the right and obligation to purchase all refined products produced by the refinery. For a more complete description of this Supply and Offtake Agreement, see the description of the Supply and Offtake Agreement in our Annual Information Form for the year ended December 31, 2007 to be filed on SEDAR at www.sedar.com. At the end of 2007, we estimate that Vitol held inventories of VGO, crude oil feedstock (both delivered and in-transit) and refined products for resale valued at approximately $818.1 million which would have otherwise been assets of Harvest.

During 2007, we issued a total of 26,194,998 Trust Units with 13,449,250 of those Trust Units issued in two public financings to raise $373.9 million at a weighted average price of $27.80 per Trust Unit, 5,922,708 Trust Units issued upon the conversion of Convertible Debentures, 6,809,987 Trust Units issued via a 29% level of participation in our distribution reinvestment programs and 13,053 Trust Units issued on the exercise of employee unit incentive plans. These issuances added $689.2 million to our equity bolstering our balance sheet ratios. In 2007, we have utilized our public financings to reduce bank borrowing incurred to fund the acquisition of North Atlantic in 2006 and Grand Petroleum in 2007 with the proceeds from the distribution reinvestment programs considered to be the balancing factor between our cash flow from operating activities, capital expenditure program and distributions.

During 2007, the trading value of our Trust Units ranged from a high of $34.97 in July to $19.75 in December. This volatility in our trading value is generally attributed to the seasonal fluctuation in refining margins and uncertainty created with the royalty review by the Province of Alberta offset by very strong crude oil prices. At the end of 2007 approximately 66% of our Unitholders were non-residents of Canada which is an increase from 54% at the end of 2006. We have experienced a reduction in the participation in our distribution reinvestment programs as the non-resident ownership of our Trust Units increases. We understand this is due to our Premium Distribution Re-investment Plan being very popular with our Unitholders resident in Canada. With the ownership of our Trust Units shifting to non-residents of Canada who are not eligible for the Premium Distribution Re-investment Plan, participation in our distribution reinvestment plans has diminished.

The following summarizes the trading value of our Trust Units during 2007 through to February 2008:

	Trading Price		
Month	**High**	**Low**	**Volume**
TSX Trading			
January 2007	$ 26.22	$ 23.20	12,822,502
February 2007	$ 27.49	$ 24.81	10,036,635
March 2007	$ 29.22	$ 25.90	11,430,584
April 2007	$ 31.10	$ 27.74	10,244,956
May 2007	$ 33.16	$ 30.25	13,984,905
June 2007	$ 34.48	$ 31.38	19,605,824
July 2007	$ 34.97	$ 29.50	19,478,671
August 2007	$ 31.52	$ 26.10	17,373,101
September 2007	$ 29.40	$ 25.18	15,463,720
October 2007	$ 28.39	$ 25.92	13,236,903
November 2007	$ 26.99	$ 20.42	12,281,080
December 2007	$ 22.22	$ 19.75	7,729,610
January 2008	$ 23.56	$ 20.48	10,474,631
February 2008	$ 26.00	$ 22.49	8,552,342
NYSE Trading (in US$)			
January 2007	$ 22.20	$ 19.70	16,693,600
February 2007	$ 23.55	$ 21.18	10,059,454
March 2007	$ 25.22	$ 21.97	12,316,050
April 2007	$ 28.07	$ 24.00	10,038,123
May 2007	$ 30.70	$ 27.05	14,253,739
June 2007	$ 32.46	$ 29.47	13,474,838
July 2007	$ 33.97	$ 27.15	17,505,628
August 2007	$ 29.74	$ 24.29	23,146,747
September 2007	$ 27.94	$ 25.15	19,625,622
October 2007	$ 29.11	$ 25.94	20,887,843
November 2007	$ 28.96	$ 20.50	27,496,352
December 2007	$ 22.20	$ 19.80	18,794,208
January 2008	$ 23.24	$ 20.00	18,167,009
February 2008	$ 25.70	$ 22.51	15,108,961

We are authorized to issue an unlimited number of Trust Units and as of March 7, 2008, we had 150,580,097 Trust Units outstanding, 5,394,230 of Unit Appreciation Rights outstanding (of which 3,691,600 were vested) and 498,772 awards issued under the Unit Awards Incentive Plan (of which 278,463 were vested). In addition, we have six series of Convertible Debentures outstanding that are convertible into 19,633,017 Trust Units. Additionally one issue, $24,258,000 principal amount of 10.5% debentures, matured in January 2008 which we settled with the issuance of 1,116,593 Trust Units.

Effective June 22, 2007 with the enacting of Bill C-52, our future issuance of Trust Units and Convertible Debentures will be limited by the “normal growth” guidelines contained therein. At the end of 2007, we estimate that we could issue approximately $550 million of Trust Units and Convertible Debentures in each of 2008, 2009 and 2010 with any unused “normal growth” available for use prior to 2011. In addition, we are entitled to issue approximately $590 million to replace debt held by the mutual fund trust on October 31, 2006. Trust Units issued pursuant to participation in our distribution reinvestment programs will be included as issuances in our “normal growth” limitation.

Through a combination of cash from operating activities, unused credit capacity and the working capital provided by the Supply and Offtake Agreement with Vitol, it is anticipated that we will have enough liquidity to fund future operations and forecasted capital expenditures although cash from operating activities used to fund ongoing operations may reduce the amount of future distributions paid to unitholders. At the end of 2007, our weighted average cost of capital, including our current level of distributions and the recent trading value of our Trust Units, is approximately 11.25%.

Distributions to Unitholders and Taxability

Harvest is an integrated energy trust with a declining asset base in our upstream operations and a "near perpetual" asset in our downstream operations. The future of our upstream operations relies on successful exploitation of our existing reserves, future development activities and strategic acquisitions to replace existing production and add additional reserves, as well as future petroleum and natural gas prices. With a prudent maintenance program, our downstream assets are expected to have a long life with additional growth in profitability available by upgrading the high sulphur fuel oil currently produced and/or expanding our refining capacity which is expected to provide favourable incremental economics from our existing infrastructure. Future development activities and modest acquisitions in our upstream business as well as the maintenance program in our downstream business will likely be funded by our cash generated from operating activities while we will generally rely on funding more significant acquisitions and growth initiatives from some combination of cash from operating activities, issuances of Trust Units and incremental debt. To the extent that we finance acquisitions and growth initiatives from cash from operating activities, the amount of our distributions to unitholders may be reduced. Should equity capital markets or incremental debt not be available to us, our ability to make the necessary expenditures to maintain or expand our assets may be impaired and result in reductions to future distributions paid to unitholders. In our upstream business, it is not possible to distinguish between expenditures to maintain productive capacity and spending to increase productive capacity due to the numerous factors impacting reserve reporting and the natural decline in reservoirs. Accordingly, maintenance capital is not disclosed separately.

Our distributions will generally exceed the net income reported in our financial statements as a result of significant non-cash charges recorded in our income statement. In 2007, we recorded a $65.8 million charge in respect of future income tax expense and recognized a further $147.8 million in unrealized loss on price risk management contracts. In addition, we recorded a provision of $526.7 million in respect of depreciation and depletion which was based primarily on our historic costs of property, plant and equipment and does not accurately represent the fair value or replacement cost of the assets, nor do they affect cash generated in the current period. These charges result in significant changes to net income with no impact on cash from operating activities. Accordingly, we anticipate that over time our net income may fluctuate significantly from our cash flow from operating activities as well as distributions to unitholders. During 2007, our distributions to unitholders exceeded our net loss of $25.7 million by $636.0 million as compared to the prior year where our distributions to unitholders exceeded our net income of $136.0 million by $332.7 million. In instances where our distributions exceed our net earnings, a portion of the distribution may represent a return of capital rather than a distribution of earnings. During 2007, our distributions declared totaled $610.3 million, representing 95% of cash from operating activities.

Management, together with the Board of Directors of Harvest, continually assess the level of our monthly distributions in light of commodity price expectations, currency exchange rates, production and throughput projections, operating cost forecasts, debt leverage and spending plans. We maintained a monthly distribution of $0.38 per Trust Unit from February 2006 through October 2007 and commencing in November 2007, have declared a monthly distribution of $0.30 per Trust Unit through April 2008, a level of distributions that reflects our expectations of future commodity prices and currency exchange rates as well as our future production and throughput volumes and operating costs.

The following table summarizes the distributions declared, the proceeds from our distribution reinvestment programs as well as distributions as a percentage of cash from operating activities for the past two years:

	Year Ended December 31		
(000s except per Trust Unit amounts)	**2007**	2006	Change
Distributions declared	**$ 610,280**	$ 468,787	30%
Per Trust Unit	**$ 4.40**	$ 4.53	(3%)
Distribution reinvestment proceeds	**$ 178,489**	$ 167,543	7%
Distributions as a percentage of cash from operating activities	**95%**	92%	3%

Throughout the first ten months of 2007, we declared monthly distributions of $0.38 per Trust Unit to Unitholders, and declared a monthly distribution of $0.30 per Trust Unit for the months of November and December 2007. The total distributions declared in 2007 was $610.3 million, which is 95% of our annual cash from operating activities. The $141.5 million increase in distributions declared during 2007 relative to 2006 is primarily due to the increase of approximately 26.2 million Trust Units outstanding following the acquisitions of Birchill and North Atlantic in 2006 along with issuance under our distribution re-investment plans and conversions of Convertible Debentures, offset by a reduction in the per unit amount of distributions declared in November and December of 2007.

Prior to January 1, 2011, the Trust is subject to tax on its taxable income less the portion that is paid or payable to the Unitholders at the end of each taxation year. For 2007 and 2006, our distributions to Unitholders were 100% taxable and the Trust had no taxable income.

OUTLOOK

Our 2008 business plan includes two significant changes as compared to our 2007 operating results. In 2008, our upstream operations will increase its focus on enhanced oil recovery and longer term value creation with capital spending of $225 million planned as compared to $300.7 million in 2007 and $376.9 million in 2006. In 2008, our enhanced oil recovery efforts will focus on fluid management projects in several of our larger oil reservoirs which we expect will ultimately reduce overall decline rates for an extended period due to improved oil recovery rates. The anticipated improved recoveries are based on maintenance of reservoir pressure and the bolstering of traditional waterflood projects with the introduction of proven chemical enhancements, such alkaline surfactant polymers. In our downstream operations, we are anticipating a robust year with no significant planned downtime for turnarounds and in the fourth quarter, an improved yield of gasoline and distillates attributed to an increase in the refinery’s visbreaking capacity.

Our 2008 capital spending focuses on drilling programs in southeast Saskatchewan, Lloydminister, Red Earth, Suffield and Hayter with approximately 120 wells anticipated accounting for approximately 65% of our 2008 capital budget. Our planned investment in infrastructure and workovers primarily relates to our reservoir management initiatives and will account for approximately twenty five percent of our 2008 spending including $8 million on the alkaline surfactant polymer project at Wainwright and a further $3 million investment in water handling capabilities at each of Bellshill Lake and Suffield to assist in re-pressurizing reservoirs. The balance of our capital program is allocated to projects necessary to maintain our existing infrastructure and does not increase production or reserves. The impact of an increased focus on reservoir management and reduced drilling activity results in a more stable production profile throughout the year as compared to a front-end loaded production profile attributed to flush production from first quarter drilling activity, particularly in Hay River. Currently, our 2008 capital spending plans have a moderate natural gas focus which could change with a relative improvement in the outlook for natural gas prices as compared to oil prices. Our more significant natural gas investments in 2008 will build on significant 2007 discoveries in west central Alberta and the addition of processing capacity at existing facilities.

We anticipate that our upstream production will average approximately 40,000 bbl/d of liquids and 93,000 mcf/d of natural gas with a moderate declining production profile throughout the year. We anticipate production will be slightly front-end loaded in the first quarter due to drilling in southeast Saskatchewan and the tie-in of approximately 1,000 bbl/d of production from our 2007 drilling program. Light and medium gravity oil, including natural gas liquids, is expected to represent approximately 49% of our total production in 2008 with heavy oil and natural gas accounting for 23% and 28% respectively. We expect operating costs will continue to be a challenge in 2008 with approximately 40% of our costs attributed to electric power and well servicing. Power costs are significant for us as we move and dispose of approximately 2 million bbl/d of water to produce 40,000 bbl/d of oil and these costs will likely increase as we enhance our reservoir management focus. For 2008, we are projecting our operating costs to be approximately $13.00 per boe as compared to $13.66 in 2007 while our 2008 general and administrative costs are expected to average about $1.40 per boe.

In our downstream operations, we are not anticipating any planned shutdowns except for the shutdown of the visbreaker to enable the commissioning of our visbreaker upgrading project, and accordingly, are anticipating a 12% increase in throughput in 2008 to 112,900 bbl/d of feedstock. In 2007, we completed a turnaround of the crude vacuum units with the expectation that our purchases of vacuum gas oil from third parties would be reduced. For 2008, we anticipate a 4,800 bbl/d reduction in vacuum gas oil purchases at a cost saving of approximately $40 million. Currently, we expect that our operating costs and purchased energy costs will aggregate to $4.75 per bbl of throughput including the impact of recently re-negotiated labour contract and a Canadian dollar at parity with the US dollar. We are also concentrating on capturing $10 million of operating cost reductions by improving energy efficiency and other operating measures which could reduce unit operating costs by $0.25 per barrel. Capital spending in our downstream operations is expected to total $63 million comprised of $22 million of mandatory/maintenance projects, $13 million discretionary projects, $25 million to complete the visbreaker project and $3 million on planning longer range refinery development projects. The cash flow contribution from our retail and wholesale marketing activities in the Province of Newfoundland and Labrador is expected to continue to add approximately $20 million of incremental cash flow to the downstream operations.

As discussed in the Cash Flow Risk Management section of this MD&A, we have refined product and WTI pricing contracts that represent approximately 79% of our cash flow exposure in the first half of 2008, 68% for the second half of 2008 and 53% for the first half of 2009. With respect to our cash flow exposure related to refined product crack spreads, we have contracts in place for approximately 10% of our 2008 exposure. We also have a modest 276 GJ/d of natural gas fixed price contracts in place. Although, we may enjoy unprecedented crude oil prices in 2008, our upside participation will be limited to an average WTI price of US$78.81/bbl within our 20,000 bbl/d of heating oil and fuel oil price risk management contracts. We have currency exchange contracts on US$18.3 million per month through to June 2008 with an average exchange rate of US$0.93 and an additional US$10.0 million per month through to December 2008 with an average exchange rate of US$0.95 representing approximately 20% of our exposure to fluctuations in the US dollar to Canadian dollar exchange rate, prior to considering the offsetting exposure of our US dollar denominated $7^{7/8}$% Senior Notes. We have also entered into contracts to fix the price of 35 MWh through to the end of December 2008 at price of $56.69 with the objective of reducing the volatility of our operating costs to fluctuating electricity costs which represent approximately 20% of our upstream operating costs.

We manage our exposure to fluctuations in interest rates by maintaining a mix of short and longer term financing with the short term financing typically carrying floating interest rates and longer term financing (our $7^{7/8}$% Senior Notes and Convertible Debentures) carrying fixed rates of interest. Our short term financing consists of borrowings under our credit facilities, $1,279.5 million at December 31, 2007, which represent approximately 60% of our total debt. Accordingly, approximately 60% of our interest rate exposure is floating and 40% is fixed. Currently, our most significant exposure to increasing interest rates is through the re-pricing of credit as we extend (or renew) our credit facilities or enter into additional longer term financings. Prior to mid-2007, our short term interest rate was approximately 70 basis points over Bankers Acceptance rates while our long term rates based on the trading price of our $7^{7/8}$% Senior Notes was 250 basis points over the ten year US Treasury Bonds. As discussed in the Liquidity and Capital Resources section of this MD&A we may defer our credit facility extension request. With respect to further reducing our borrowings under this credit facility, we continue to monitor the high yield market as well as opportunities to issue additional Convertible Debentures and Trust Units.

On January 31, 2008, approximately $24.3 million of principal amount 10.5% Convertible Debentures matured and we elected to satisfy this obligation by issuing 1,116,593 Trust Units rather than settling the obligations in cash. This same option is available on all of the $666.9 million of principal amount of Convertible Debentures issued in six series with maturities in 2009, 2010, 2012, 2013 and 2014 as to $2.7 million, $37.1 million, $174.6 million, $379.3 million and $73.2 million, respectively. While not necessarily impacting 2008, we anticipate that as these Convertible Debentures mature, or are converted into Trust Units before their maturity date, we will be able to retire $666.9 million of principal amount of unsecured debt with equity issuances.

Overall, we expect that based on current commodity price expectations, our 2008 cash from operating activities will be sufficient to fund our planned capital expenditures as well as maintain our present level of distributions. In prior years, we have balanced our cash from operating activities and the funding of capital expenditures and distributions with reliance on proceeds from our distribution re-investment programs for shortfalls. The participation level in our distribution re-investment programs was 38% in 2006. However, as the ownership of our Trust Units by non-Canadian residents increased in 2007, the participation in our Premium Distribution Re-investment Plan™ has steadily diminished as non-residents of Canada do not qualify for this program which accounts for a substantial portion of the funding from our distribution re-investment programs. As of December 31, 2007, we estimate that 66% of our Unitholders are non-Canadian residents, a significant increase from 54% at the end of 2006 and 33% in February 2006 when Harvest and Viking merged.

While we do not forecast commodity prices nor refining margins, we have entered into price risk management contracts to mitigate a substantial portion of our price volatility with the objective of stabilizing our 2008 cash flow from operating activities through a wide variety of pricing environments. The following table reflects the sensitivity of our 2008 operations to changes in the following key factors to our business including the impact of our price risk management contracts:

	Assumption		**Change**		**Impact on Cash Flow**	
WTI oil price (US$/bbl)	$	90.00	$	5.00	$	0.18 / Unit
CAD/USD exchange rate	$	1.00	$	0.05	$	0.36 / Unit
AECO daily natural gas price	$	7.00	$	1.00	$	0.19 / Unit
Refinery crack spread (US$/bbl)	$	9.00	$	1.00	$	0.27 / Unit
Upstream Operating Expenses (per boe)	$	12.90	$	1.00	$	0.14 / Unit

In our upstream business, we will continue to evaluate opportunities to acquire producing oil and/or natural gas properties as well as offer selected properties for divestment while striving to maintain or enhance our productive capability and improve our unit operating costs. In addition, we intend to be an active participant in the consolidation of the Canadian energy industry, including royalty trusts.

In our downstream business, we are currently evaluating several opportunities to expand and/or reconfigure the refinery and have engaged SNC Lavalin to review the technical and economic feasibility of these options. The options include a project to convert approximately 30,000 bbl/d of high sulphur fuel oil to higher valued refined products, expand processing capacity supported by existing infrastructure and enhancing capability to refine a heavier and lower cost crude feedstock to improve margins. SNC Lavalin is expected to complete its study and provide its report by June 2008. With approval to proceed dependent on the outlook on worldwide growth in refining capacity, an expansion could boost throughput capacity and may take three to five years to complete. With costs expected to exceed $1 billion, we could either use our capital or a tolling processing arrangement from a producer seeking captive refining capacity to process its crude oil. There are also economic gains to be had by upgrading our combustion technologies.

The changes to Canada's Income Tax Act to apply a tax on distributions from publicly traded mutual fund trusts, including Harvest, have now been enacted with an effective date of January 1, 2011. We continue to search and validate various capital structures, balancing the benefits of the remaining years of tax efficient distributions against the longer term benefits of continuing with a growth strategy beyond the announced "normal growth" limitations. On December 14, 2007, Bill C-28 implemented reductions in the federal corporate income tax rates which will also apply to the tax on distributions from publicly traded mutual fund trusts. See the Future Income Tax section in this MD&A for a more detailed discussion.

SUMMARY OF FOURTH QUARTER RESULTS

	Three months ended December 31						
	2007			2006			
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total	Change
Revenues	**308,022**	**624,512**	**932,534**	273,110	460,359	733,469	27%
Royalties	**(53,410)**	**-**	**(53,410)**	(50,725)	-	(50,725)	5%
Net revenues	**254,612**	**624,512**	**879,124**	222,385	460,359	682,744	29%
Purchased product for resale and processing	**-**	**579,765**	**579,765**	-	386,014	386,014	50%
Operating expenses	**76,100**	**81,271**	**157,371**	69,298	34,063	103,361	52%
General and administrative expenses	**7,979**	**441**	**8,420**	6,714	-	6,714	25%
Less: Unit based compensation expenses	**(3,688)**	**48**	**(3,640)**	(167)	-	(167)	2080%
Total cash general and administrative expenses	**4,291**	**489**	**4,780**	6,547	-	6,547	(27%)
Transportation and marketing	**2,347**	**7,895**	**10,242**	2,919	5,060	7,979	28%
Depreciation, depletion and accretion	**115,176**	**17,746**	**132,922**	116,262	15,482	131,744	1%
Net income per segment	**56,698**	**(62,654)**	**(5,956)**	27,359	19,740	47,099	(113%)
Realized losses (gains) on risk management contracts			**17,375**			5,996	190%
Unrealized losses (gains) on risk management contracts			**122,739**			(16,213)	857%
Interest and other financing charges			**36,959**			41,184	(10%)
Corporate costs(2)			**(69,444)**			14,599	(576%)
Net (loss) income			**(113,585)**			1,533	(7509%)
Per Trust Unit, basic			**(0.77)**			0.01	(7800%)
Per Trust Unit, diluted			**(0.77)**			0.01	(7800%)
Cash From Operating Activities			**87,998**			140,543	37%
Per Trust Unit, basic			**0.60**			1.21	(50%)
Per Trust Unit, diluted			**0.60**			1.16	(48%)
Distributions declared			**144,681**			134,974	(7%)
Distributions declared, per Trust Unit			**0.98**			1.14	(14%)
Distributions declared as a percentage of Cash From Operations			**164%**			96%	68%
UPSTREAM OPERATIONS							
Daily Production							
Light / medium oil (bbl/d)			**26,640**			28,152	(5%)
Heavy oil (bbl/d)			**13,354**			13,967	(4%)
Natural gas liquids (bbl/d)			**2,595**			2,649	(2%)
Natural gas (mcf/d)			**94,961**			112,006	(15%)
Total daily sales volume (boe/d)			**58,416**			63,436	(8%)
Operating Netback(1) ($/BOE)							
Revenue			**57.32**			46.80	22%
Royalties as percent of revenue			**(9.94)**			(8.69)	14%
Operating expense			**(14.16)**			(11.87)	19%
Transportation expense			**(0.44)**			(0.50)	(12%)
Operating Netback(1)			**32.78**			25.74	27%
Cash capital expenditures			**30,643**			90,358	(66%)
DOWNSTREAM OPERATIONS(3)							
Average daily throughput (bbl/d)			**61,717**			86,890	(29%)
Aggregate throughput (mbbl)			**5,678**			6,343	(10%)
Average Refining Margin (US$/bbl)			**6.00**			9.32	(36%)
Cash capital expenditures			**16,889**			21,411	(21%)

(1) This is a non-GAAP measure, please refer to "Non-GAAP Measure" in this MD&A.

(2) Includes foreign exchange losses, taxes and amounts realized on the series of US dollar forward purchase contracts entered into with respect to the purchase of North Atlantic

(3) Downstream operations acquired on October 19, 2006.

Our 2007 fourth quarter results are not directly comparable to our 2006 fourth quarter results due to the acquisition of the North Atlantic during the fourth quarter of 2006, the turnaround activity at the refinery in the fourth quarter of both 2007 and 2006, and the acquisition of Grand Petroleum in the third quarter of 2007.

Upstream Operations

Our 2007 fourth quarter revenues increased $34.9 million over the same period in the prior year as a result of our realized commodity prices increasing by $10.52/boe (22%) due to significantly higher crude oil prices. Offsetting the increase in our realized commodity prices in the fourth quarter is a decrease in production volumes of 5,020 boe/d as compared to the prior period due to normal decline on our crude oil and natural gas production. Light / medium oil sales revenue for the three month period ended December 31, 2007 was $34.1 million (or 24%) higher than in same period in the prior year due to a favourable price variance of $41.6 million and an unfavourable volume variance of $7.5 million. Heavy oil revenues for the three months ended December 31, 2007 increased by $11.7 million (or 24%) due to a favourable price variance of $13.8 million and an unfavourable volume variance of $2.1 million. Natural gas sales revenue decreased by $15.9 million (or 22%) for the three months ended December 31, 2007 over the same period in 2006, which reflects an unfavourable price variance of $4.9 million and an unfavourable volume variance of $11.0 million.

For the three months ended December 31, 2007, our net royalties as a percentage of revenue were 17.3% ($53.4 million) as compared to 18.6% ($50.7 million) in the same period in 2006. The decrease in the royalty rate is mainly due to receiving crown royalty refunds on some of our shut in gas-over-bitumen production in the fourth quarter of 2007.

Operating expenses increased by $6.8 million (or 10%) for the three months ended December 31, 2007 compared to the same period in the prior year which reflects cost pressures in the western Canadian oil and natural gas sector.

For the three months ended December 31, 2007, Cash G&A increased by $1.3 million (or 19%) compared to the same period in the prior year. This increase is reflective of additional costs relating to consultant fees and generally higher costs to retain technically qualified staff in the western Canadian petroleum and natural gas industry.

After capital spending of $148.5 million, $48.2 million, and $73.3 million in the first, second and third quarters of 2007, respectively, capital spending in our upstream segment in the fourth quarter totaled $30.6 million which was mainly focused on tying-in our drilling results.

Downstream Operations

Our fourth quarter 2007 downstream operating results are not very comparable with the same period in the prior year, as the refinery was acquired midway through the fourth quarter of 2006 and during both periods the refinery undertook significant turnaround activity. Our operating results in the fourth quarter of 2007 reflect the impact of two planned shutdowns and weaker refining margins relative to the first and second quarters of 2007. By early December 2007, the refinery had returned to full operations with throughput averaging 109,611 bbl/d. For the fourth quarter 2006, our results reflect the impact of an extended turnaround commencing October 1, 2006 with the refinery returning to full operations near the end of November 2006 only to experience additional downtime in December 2006 due to a pipe rupture and a disruption in electric power service.

Corporate

Interest expense decreased by $4.2 million for the three months ended December 31, 2007 relative to the same period in the prior year due to a decrease in our total debt outstanding as a result of the issuance of $230.0 million of principal amount of Convertible Debentures and 13,499,250 Trust Units for total net proceeds of $576.0 million in the first half of 2007.

In the fourth quarter of 2007 we realized a $17.4 million loss and a $122.7 million unrealized loss on our risk management contracts as compared to a realized loss of $6.0 million and a $16.2 million unrealized gain in the same period in 2006. The significant unrealized loss in the fourth quarter of 2007 is due to our refined products and WTI price contracts as the refined product contracts were placed in mid-2007 when the WTI benchmark price was approximately US$71.00 and the NYMEX price for heating oil and Platts Index for fuel oil were approximately US$2.00 per gallon and US$55.00 per barrel, respectively, as compared to the 2007 year end closing prices of US$95.98 for WTI, US$2.64 per gallon for NYMEX heating oil and US$75.15 per barrel for Platts fuel oil

SUMMARY OF QUARTERLY RESULTS

The table and discussion below highlight our fourth quarter 2007 performance over the preceding seven quarters on select measures:

	2007				2006			
(000s except where noted)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue, net of royalties	**$ 879,124**	$ 1,007,786	$ 1,133,450	$ 1,025,512	$ 682,744	$ 259,818	$ 257,103	$ 181,160
Net income (loss)	**$ (113,585)**	$ 11,811	$ 6,248	$ 69,850	$ 1,533	$ 107,768	$ 60,682	$ (33,937)
Per Trust Unit, basic[1]	**$ (0.77)**	$ 0.08	$ 0.05	$ 0.55	$ 0.01	$ 1.01	$ 0.60	$ (0.41)
Per Trust Unit, diluted[1]	**$ (0.77)**	$ 0.08	$ 0.05	$ 0.55	$ 0.01	$ 0.99	$ 0.60	$ (0.41)
Cash from operating activities	**$ 87,998**	$ 191,049	$ 251,218	$ 111,048	$ 140,543	$ 143,597	$ 135,581	$ 88,164
Per Trust Unit, basic	**$ 0.60**	$ 1.31	$ 1.88	$ 0.87	$ 1.21	$ 1.35	$ 1.34	$ 1.07
Per Trust Unit, diluted	**$ 0.60**	$ 1.22	$ 1.67	$ 0.84	$ 1.16	$ 1.31	$ 1.30	$ 1.07
Distributions per Unit, declared	**$ 0.98**	$ 1.14	$ 1.14	$ 1.14	$ 1.14	$ 1.14	$ 1.14	$ 1.11
Total long term financial liabilities	**$ 2,172,417**	$ 2,072,870	$ 1,961,748	$ 2,409,241	$ 2,488,524	$ 1,105,728	$ 746,840	$ 735,896
Total assets	**$ 5,451,683**	$ 5,585,651	$ 5,613,333	$ 5,800,346	$ 5,745,558	$ 4,076,771	$ 3,455,918	$ 3,470,653

(1) The sum of the interim periods does not equal the total per year amount as there were large fluctuations in the weighted average number of Trust Units outstanding in each individual quarter.

Net revenues have generally increased steadily over the eight quarters with significantly higher revenue in the Second and Third Quarters of 2006 over the preceding quarters due to the incremental revenue from the Viking acquisition in February 2006 along with stronger commodity prices including narrowing crude oil differentials. In the Fourth Quarter of 2006, the significant increase in revenue over the prior quarter is attributed to the North Atlantic acquisition which is a margin business with significant revenues coupled with significant costs for crude oil feedstock. In the second half of 2007 net revenues decreased from the first half of 2007 due to the Refinery's lower realized prices and decreased throughput due to two planned shutdowns. The growth in cash from operating activities is closely aligned with the growth in net revenues and is attributed to the same factors as the growth in net revenues, reflecting the cyclical nature of the downstream segment in 2007.

Net income reflects both cash and non-cash items. Changes in non-cash items, including future income tax, DDA&A expense, unrealized foreign exchange gains and losses, unrealized gains and losses on risk management contracts and Trust Unit right compensation expense cause net income to vary significantly from period to period. In the Second Quarter of 2007 Bill C-52 was substantively enacted, which imposed a new tax on distributions from publicly traded income trusts resulting in a large future income tax expense in the quarter. In the Fourth Quarter of 2007 Bill C-28 implemented reductions in the federal corporate income tax rates which will also apply to the tax on distributions from publicly traded mutual fund trusts, resulting in a significant future income tax recover in the quarter. Additionally, the volatility in net income (loss) between quarters in 2006 and 2007 is due to the changes in the fair value of our risk management contracts and this is the primary reason why our net income (loss) does not reflect the same trends as net revenues or cash from operating activities.

Growth in total assets over the last eight quarters is directly attributed to our acquisition of Viking in the first quarter of 2006, Birchill in the Third Quarter of 2006 and North Atlantic in the Fourth Quarter of 2006. The changes in our total long term financial liabilities is primarily due to the impact of our acquisitions, offset by our issuance of Trust Units and the net cash surplus of cash from operating activities over our distributions to Unitholders.

CRITICAL ACCOUNTING ESTIMATES

There are a number of critical estimates underlying the accounting policies applied when preparing the consolidated financial statements due to timing differences between when certain activities take place and when these activities are reported. Changes in these estimates could have a material impact on our reported results.

Reserves

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. In the process of estimating the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions, such as:

- Expected reservoir characteristics based on geological, geophysical and engineering assessments;
- Future production rates based on historical performance and expected future operating and investment activities;
- Future oil and gas prices and quality differentials; and
- Future development costs.

We follow the full cost method of accounting for our oil and natural gas activities. All costs of acquiring oil and natural gas properties and related exploration and development costs, including overhead charges directly related to these activities, are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against income, and renewals and enhancements that extend the economic life of the capital assets are capitalized. The provision for depletion and depreciation of petroleum and natural gas assets is calculated on the unit-of-production method, based on proved reserves as estimated by independent petroleum engineers.

Reserve estimates impact net income through depletion, the determination of asset retirement obligations and the application of an impairment test. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income, capital assets and asset retirement obligations.

Asset Retirement Obligations

In the determination of our asset retirement obligations, management is required to make a significant number of estimates with respect to activities that will occur in many years to come. In arriving at the recorded amount of the asset retirement obligation numerous assumptions are made with respect to ultimate settlement amounts, inflation factors, credit adjusted risk free discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligation also results in an increase to the carrying cost of capital assets. The obligation accretes to a higher amount with the passage of time as it is determined using discounted present values. A change in any one of the assumptions could impact the estimated future obligation and in return, net income. It is difficult to determine the impact of a change in any one of our assumptions. As a result, a reasonable sensitivity analysis cannot be performed.

Impairment of Capital Assets

Numerous estimates and judgments are involved in determining any potential impairment of capital assets. The most significant assumptions in determining future cash flows are future prices and reserves for our upstream operations and expected future refining margins for our downstream operations.

The estimates of future prices and refining margins require significant judgments about highly uncertain future events. Historically, oil, natural gas and refined product prices have exhibited significant volatility. The prices used in carrying out our impairment tests for each operating segment are based on prices derived from a consensus of future price forecasts among industry analysts. Given the number of significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate.

If forecast WTI crude oil prices were to fall by 20%, the initial assessment of impairment of our upstream assets would not change; however, below that level, we would likely experience an impairment. Although oil and natural gas prices fluctuate a great deal in the short-term, they are typically stable over a longer time horizon. This mitigates potential for impairment.

Similarly, for our downstream operations, if forecast refining margins were to fall by more than 25%, it is likely that our downstream assets would experience an impairment despite the expected seasonal volatility in earnings.

Reductions in estimated future prices may also have an impact on estimates of economically recoverable proved reserves.

Any impairment charges would reduce our net income.

It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserve estimate and the estimated undiscounted cash flows is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

Goodwill

Goodwill is recorded on a business combination when the total purchase consideration exceeds the fair value of the net identifiable assets and liabilities of the acquired entity. The goodwill balance is not amortized, however, must be assessed for impairment at least annually. Impairment is initially determined based on the fair value of a reporting unit compared to its book value. Any impairment must be charged to earnings in the period the impairment occurs. Harvest has a goodwill balance for each of our upstream and downstream operations. As at December 31, 2007, we have determined there was no goodwill impairment in either of our reporting units.

Employee Future Benefits

We maintain a defined benefit pension plan for the employees of North Atlantic. Obligations under employee future benefit plans are recorded net of plan assets where applicable. An independent actuary determines the costs of our employee future benefit programs using the projected benefit method. The determination of these costs requires management to estimate or make assumptions regarding the expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, employee turnover, discount rates and return on plan assets. The obligation and expense recorded related to our employee future benefit plans could increase or decrease if there were to be a change in these estimates. Pension expense represented less than 0.5% of our total expenses for 2007 (0.5% in 2006).

Purchase Price Allocations

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair values at the time of the acquisitions. The excess of the purchase price over the assigned fair values of the identifiable assets and liabilities is allocated to goodwill. In determining the fair value of the assets and liabilities we are often required to make assumptions and estimates about future events, such as future oil and gas prices, refining margins and discount rates. Changes in any of these assumptions would impact amounts assigned to assets and liabilities and goodwill in the purchase price allocation and as a result, future net earnings.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

Convergence of Canadian GAAP with International Financial Reporting Standards

In early 2007, Canada's Accounting Standards Board ("AcSB") issued a decision summary with respect to a previously issued strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards ("IFRS"). In early 2008, it was confirmed by the AcSB that the transitions date from Canadian GAAP to IFRS will be January 1, 2011. We are currently evaluating our options with respect to this change and accordingly it is premature to assess the impact of the initiative, if any, on our financial statements at this time.

Financial Instruments – Disclosures and Presentation

On December 1, 2006, the AcSB issued the following two new standards regarding the disclosure and presentation of financial instruments with an implementation date for annual and interim financial statements beginning on or after October 1, 2007.

- Section 3862 – *Financial Instruments – Disclosures*

  This standard requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks.

- Section 3863 – *Financial Instruments – Presentation*

  This standard establishes standards for presentation of financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset.

Also on December 1, 2006, the AcSB issued a new standard regarding *Capital Disclosure* requiring the disclosure of information about an entity’s objectives, policies and processes for managing capital; quantitative data about what the entity regards as capital; whether the entity has complied with any externally imposed capital requirements; and if it has not complied, the consequences of such non-compliance. This standard also has an implementation date for annual and interim financial statements beginning on or after October 1, 2007.

In June 2007, the AcSB issued section 3031, Inventories, which replaces the existing inventories standard. This new standard provides additional guidance with respect to the measurement and disclosure requirements for inventories, requiring inventories to be valued at the lower of cost and net realizable value. This standard is to be adopted for fiscal years beginning on or after January 1, 2008. We do not expect the adoption of this section to have a material impact on our net income or financial position.

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062 Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. The new Section will be effective on January 1, 2009. Section 3062 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. We are currently evaluating the impact of the adoption of this new Section, however do not expect a material impact on our Consolidated Financial Statements.

OPERATIONAL AND OTHER BUSINESS RISKS

Our financial and operating performance is subject to risks and uncertainties which include, but are not limited to: upstream operations, downstream operations, reserve estimates, commodity prices, ability to obtain financing, environmental, health and safety risk, regulatory risk, disruptions in the supply of crude oil and delivery of refined products, employee relations, and other risks specifically discussed previously in this MD&A. We intend to continue executing our business plan to create value for Unitholders by paying stable monthly distributions and increasing the net asset value per Trust Unit. All of our risk management activities are carried out under policies approved by the Board of Directors of Harvest Operations, and are intended to mitigate the risks noted above as follows:

The following summarizes the more significant risks of our upstream and downstream operations. See our Annual Information Form for a full description of these risks as well as risks associated with our royalty trust structure.

Operation of oil and natural gas properties:

- Applying a proactive management approach to our properties;
- Selectively adding skilled and experienced employees and providing encouragement and opportunities to maintain and improve technical competence; and

Operation of a refining and petroleum marketing business

- Maintaining a proactive approach to managing the supply of feedstock and sale of refined products (including the Supply and Offtake Agreement with Vitol Refining S.A.) to ensure the continuity of supply of crude oil to the refinery and the delivery of refined products from the refinery;
- Allocating sufficient resources to ensure good relations are maintained with our non-unionized and unionized work force; and
- Selectively adding experienced refining management to further strengthen our "in-house" management team.

Estimates of the quantity of recoverable reserves:

- Acquiring oil and natural gas properties that have high-quality reservoirs combined with mature, predictable and reliable production and thus reduce technical uncertainty;
- Subjecting all property acquisitions to rigorous operational, geological, financial and environmental review; and
- Pursuing a capital expenditure program to reduce production decline rates, improve operating efficiency and increase ultimate recovery of the resource-in-place.

Commodity price exposures:

- Maintaining a risk-management policy and committee to continuously review effectiveness of existing actions, identify new or developing issues and devise and recommend to the Board of Directors of Harvest Operations action to be taken;
- Executing risk management contracts with a portfolio of credit-worthy counterparties;
- Maintaining an efficient cost structure to maximize product netbacks; and
- Limiting the period of exposure to price fluctuations between crude oil prices and product prices by entering into contracts such that crude oil feedstock will be priced based on the price at or near the time of delivery to the refinery, which may be as much as 24 days subsequent to the time the feedstock is initially loaded onto the shipping vessel. Thereby, minimizing the time between the pricing of the feedstock and the refined products with the objective of maintaining margins.

Financial risk:

- Monitoring financial markets to ensure the cost of debt and equity capital is kept as low as reasonably possible;
- Retaining a portion of cash flows to finance capital expenditures and future property acquisitions; and
- Carrying adequate insurance to cover property and business interruption losses.

Environmental, health and safety risks:

- Adhering to our safety programs and keeping abreast of current industry practices for both the oil and natural gas industry as well as the refining industry; and
- Committing funds on an ongoing basis toward the remediation of potential environmental issues.

Changing government policy, including revisions to royalty legislation, income tax laws, and incentive programs related to the oil and natural gas industry:

- Retaining an experienced, diverse and actively involved Board of Directors to ensure good corporate governance; and
- Engaging technical specialists when necessary to advise and assist with the implementation of policies and procedures to assist in dealing with the changing regulatory environment.

CHANGES IN REGULATORY ENVIRONMENT

On October 25, 2007, the Government of Alberta released its New Royalty Framework outlining changes that effective January 1, 2009 will increase the royalty rates on conventional oil and gas, oil sands and coalbed methane using a price-sensitive and volume-sensitive sliding rate formula for both conventional oil and natural gas. While there are considerable details to be provided, our preliminary assessment is that the impact of the changes on Harvest will be modest, as many of our oil and natural gas wells will be considered low productivity wells that continue to attract favourable royalty treatment. Based on the information available and assuming royalties will continue to be based on field gate prices realized by producers, our analysis indicates that if our field gate prices are less than $53.00, our oil royalties will be lower and if prices are higher, our royalties will increase and similarly for natural gas, if our gas plant prices are less than $7.00, our royalties will be lower and if prices are higher, our royalties will increase. Of particular concern is the royalty rates on natural gas where production from recently drilled wells may qualify as high productivity for a period of time and attract a royalty that is 15% to 20% higher than under the current royalty regime and this could significantly penalize the economics of our drilling and natural gas wells. Generally, we will pay higher royalties if commodity prices are high and lower royalties on most of our wells as they will be considered to be low productivity wells.

In 2007, the Government of Alberta introduced the Climate Change and Emissions Management Amendment Act which intends to reduce greenhouse gas emissions intensity from large emitting facilities. On January 24, 2008, the Government of Alberta announced their plan to reduce projected emissions in the province by 50% under the new climate change plan by 2050. This will result in real reductions of 14% below 2005 levels. The Government of Alberta stated they will form a government-industry council to determine a go-forward plan for implementing technologies, which will significantly reduce greenhouse gas emissions by capturing air emissions from industrial sources and locking them permanently underground in deep rock formations.

In 2002, the Government of Canada ratified the Kyoto Protocol which calls for Canada to reduce its greenhouse gas emissions to specified levels. On April 26, 2007, the Government of Canada released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the “Action Plan”) which includes a regulatory framework for air emissions. This Action Plan is to regulate the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. On March 10, 2008, the Government of Canada released “Turning the Corner” outlining additional details to implement their April 2007 commitment to cut greenhouse gas emissions by an absolute 20% by 2020. “Turning the Corner” sets out a framework to establish a market price for carbon emissions and sets up a carbon emission trading market to provide incentives for Canadians to reduce their greenhouse gas emissions. In addition, the regulations include new measures for oil sands developers that require an 18% reduction from 2006 levels by 2010 for existing operations and for oil sands operations commencing in 2012, a carbon capture and storage capability. There is no mention of targeting reductions for unintentional fugitive emissions for conventional producers. Companies will be able to choose the most cost effective way to meet their emissions reduction targets from in-house reductions, contributions to time-limited technology funds, domestic emissions trading and the United Nations’ Clean Development Mechanism. Companies that have already reduced their greenhouse gas emissions prior to 2006 will have access to a limited one-time credit for early adoption. Giving the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, and the lack of detail in the Government of Canada’s announcement, it is not possible to assess the impact of the requirements on our operations and financial performance.

NON-GAAP MEASURES

Throughout this MD&A we have referred to certain measures of financial performance that are not specifically defined under Canadian GAAP. Cash G&A and Operating Netbacks are non-GAAP measures used extensively in the Canadian energy trust sector for comparative purposes. Cash G&A are G&A expenses excluding the effect of our unit based compensation plans, while Operating Netbacks are always reported on a per boe basis, and include gross revenue, royalties, operating expenses, and transportation and marketing expenses. Gross Margin is commonly used in the refining industry to reflect the net funds received from the sale of refined products after considering the cost to purchase the feedstock and is calculated by deducting purchased products for resale and processing from total revenue. Earnings From Operations is also commonly used in the petroleum and natural gas and refining industries to reflect operating results before items not directly related to operations.

Disclosure Controls and Procedures and Internal Control over Financial Reporting

Under the supervision of our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2007 as defined under the rules adopted by the Canadian securities regulatory authorities and the US Securities and Exchange Commission. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2007, our disclosure controls and procedures were effective to ensure that information required to be disclosed by Harvest in reports it files or submits to Canadian and US securities authorities was recorded, processed, summarized and reported within the time period specified in Canadian and US securities laws and was accumulated and communicated to Harvest's management, including its Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures.

Management is responsible for establishing and maintaining internal control over our financial reporting. Our internal control is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with Canadian Generally Accepted Accounting Principles. Management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated in the effectiveness of our internal control over financial reporting as of December 31, 2007. The evaluation was based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management has concluded that as of December 31, 2007, we had effective internal control over financial reporting.

The effectiveness of our internal control over financial reporting as of December 31, 2007 was audited by KPMG, an independent registered public accounting firm, as stated in their report, which is included in our audited consolidated financial statements for the year ended December 31, 2007.

During the year ended December 31, 2007, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting except for the appointment of a Chief Operating Officer – Downstream. The appointment enhanced our oversight of these operations.

Based on their inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter now well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control systems are met.

ADDITIONAL INFORMATION

Further information about us, including our Annual Information Form, can be accessed under our public filings found on SEDAR at www.sedar.com or at www.harvestenergy.ca. Information can also be found by contacting our Investor Relations department at (403) 265-1178 or at 1-866-666-1178.

MANAGEMENT’S REPORT

In management’s opinion, the accompanying consolidated financial statements of Harvest Energy Trust (the “Trust”) have been prepared within reasonable limits of materiality and in accordance with Canadian generally accepted accounting principles. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to March 12, 2008. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management’s authorization.

Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). We have concluded that as of December 31, 2007, our internal controls over financial reporting were effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The consolidated financial statements and the Trusts’ internal control over financial reporting have been examined by KPMG LLP, Independent Registered Public Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles. The Independent Registered Public Accountants Report outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the Independent Registered Public Accountants and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Trust.

John E. Zahary
President and
Chief Executive Officer

Robert W. Fotheringham
Chief Financial Officer

Calgary, Alberta
March 12, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Harvest Operations Corp. on behalf of Harvest Energy Trust and the Unitholders of Harvest Energy Trust

We have audited Harvest Energy Trust's ("the Trust") internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

An entity's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. An entity's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have conducted our audits on the consolidated financial statements in accordance with Canadian generally accepted auditing standards. With respect to the years ended December 31, 2007 and 2006, we also have conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our report dated March 12, 2008, expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 12, 2008

AUDITORS' REPORT

To the Unitholders of Harvest Energy Trust

We have audited the consolidated balance sheets of Harvest Energy Trust (the "Trust") as at December 31, 2007 and 2006 and the consolidated statements of income and comprehensive (loss) income, unitholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. With respect to the consolidated financial statements for the years ended December 31, 2007 and 2006, we also conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust's internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 12, 2008 expressed an unqualified opinion on the effectiveness of the internal control over financial reporting.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 12, 2008

COMMENTS BY AUDITORS FOR UNITED STATES READERS ON CANADA – UNITED STATES REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Trust's financial statements, such as the change described in note 3 to the consolidated financial statements as at December 31, 2007 and 2006 and for the years then ended. Our report to the unitholders dated March 12, 2008, is expressed in accordance with Canadian reporting standards, which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 12, 2008

CONSOLIDATED BALANCE SHEETS

As at December 31
(thousands of Canadian dollars)

		2007		2006
Assets				
Current assets				
Cash	**$**	**-**	$	10,006
Accounts receivable and other		**215,803**		257,131
Fair value of risk management contracts *[Note 18]*		**16,442**		17,914
Prepaid expenses and deposits		**15,144**		12,713
Inventories *[Note 5]*		**58,934**		23,792
		306,323		321,556
Deferred charges and other non-current assets *[Note 8]*		**-**		25,067
Fair value of risk management contracts *[Note 18]*		**-**		9,843
Property, plant and equipment *[Notes 6]*		**4,197,507**		4,400,552
Intangible assets *[Note 7]*		**95,075**		122,362
Goodwill *[Note 4]*		**852,778**		866,178
	$	**5,451,683**	$	5,745,558
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities *[Note 9]*	**$**	**270,243**	$	294,582
Cash distribution payable		**44,487**		46,397
Current portion of convertible debentures *[Notes 12]*		**24,273**		-
Fair value deficiency of risk management contracts *[Note 18]*		**131,020**		26,764
		470,023		367,743
Bank loan *[Note 11]*		**1,279,501**		1,595,663
$7^{7/8}$% Senior notes *[Note 13]*		**241,148**		291,350
Convertible debentures *[Notes 12]*		**627,495**		601,511
Fair value deficiency of risk management contracts *[Note 18]*		**35,095**		2,885
Asset retirement obligation *[Note 10]*		**213,529**		202,480
Employee future benefits *[Note 17]*		**12,168**		12,227
Deferred credit		**710**		794
Future income tax *[Note 16]*		**86,640**		-
Unitholders' equity				
Unitholders' capital *[Note 14]*		**3,736,080**		3,046,876
Equity component of convertible debentures		**39,537**		36,070
Accumulated income		**246,865**		271,155
Accumulated distributions		**(1,340,349)**		(730,069)
Accumulated other comprehensive (loss) income *[Note 3]*		**(196,759)**		46,873
		2,485,374		2,670,905
	$	**5,451,683**	$	5,745,558

Commitments, contingencies and guarantees [Note 20]
Subsequent events [Note 22]
See accompanying notes to these consolidated financial statements.

Approved by the Board of Directors:

((signed))
Hector J. McFadyen
Director

((signed))
Verne G. Johnson
Director

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE (LOSS) INCOME

For the Years Ended December 31

(thousands of Canadian dollars, except per Trust Unit amounts)

		2007		2006
Revenue				
Petroleum, natural gas, and refined product sales	**$**	**4,283,013**	$	1,580,934
Royalty expense		**(213,413)**		(200,109)
		4,069,600		1,380,825
Expenses				
Purchased products for processing and resale		**2,667,714**		386,014
Operating		**530,208**		276,537
Transportation and marketing		**46,916**		17,202
General and administrative *[Note 15]*		**36,328**		28,372
Transaction costs		**-**		12,072
Realized net losses on risk management contracts		**26,291**		44,808
Unrealized net losses (gains) on risk management contracts		**147,781**		(52,179)
Interest and other financing charges on short term debt, net		**5,584**		4,864
Interest and other financing charges on long term debt		**152,201**		78,828
Depletion, depreciation, amortization and accretion		**526,741**		429,470
Foreign exchange loss (gain)		**(109,316)**		21,100
Large corporations tax and other tax		**(974)**		(9)
Future income tax expense (recovery) *[Note 16]*		**65,802**		(2,300)
		4,095,276		1,244,779
Net (loss) income for the year		**(25,676)**		136,046
Cumulative Translation Adjustment		**(243,632)**		-
Comprehensive (loss) income for the period *[Note 3]*	$	**(269,308)**	$	136,046
Net income per trust unit, basic *[Note 14]*	**$**	**(0.19)**	$	1.34
Net income per trust unit, diluted *[Note 14]*	**$**	**(0.19)**	$	1.33

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY
For the Years Ended December 31
(thousands of Canadian dollars)

	Unitholders' Capital	Equity Component of Convertible Debentures	Accumulated Income	Accumulated Distributions	Accumulated Other Comprehensive (Loss) Income *[Note 3]*	Total
At December 31, 2005	**$ 747,312**	**$ 2,639**	**$ 135,665**	**$ (261,282)**	**$ -**	**$ 624,334**
Issued in exchange for assets of Viking *[Note 4(e)]*	1,638,131	-	-	-	-	1,638,131
Issued for cash						
August 17, 2006	230,118	-	-	-	-	230,118
November 22, 2006	258,848	-	-	-	-	258,848
Equity component of convertible debenture issuances						
10.5% Debentures Due 2008	-	9,301	-	-	-	9,301
6.40% Debentures Due 2012	-	14,822	-	-	-	14,822
7.25% Debentures Due 2013	-	11,800	-	-	-	11,800
Convertible debenture conversions						
9% Debentures Due 2009	551	-	-	-	-	551
8% Debentures Due 2009	1,550	(12)	-	-	-	1,538
6.5% Debentures Due 2010	3,563	(223)	-	-	-	3,340
10.5% Debentures Due 2008	10,761	(2,238)	-	-	-	8,523
6.40% Debentures Due 2012	231	(19)	-	-	-	212
Exchangeable share retraction	2,648	-	(556)	-	-	2,092
Exercise of unit appreciation rights and other	12,034	-	-	-	-	12,034
Issue costs	(26,414)	-	-	-	-	(26,414)
Foreign currency translation adjustment	-	-	-	-	46,873	46,873
Net income	-	-	136,046	-	-	136,046
Distributions and distribution reinvestment plan	167,543	-	-	(468,787)	-	(301,244)
At December 31, 2006 *[Note 3]*	**3,046,876**	**36,070**	**271,155**	**(730,069)**	**46,873**	**2,670,905**
Adjustment arising from change in accounting policies *[Note 3]*	(49)	-	1,386	-	-	1,337
Issued for cash						
February 1, 2007	143,834	-	-	-	-	143,834
June 1, 2007	230,029	-	-	-	-	230,029
Equity component of convertible debenture issuances						
7.25% Debentures Due 2014	-	13,100	-	-	-	13,100
Convertible debenture conversions						
9% Debentures Due 2009	250	-	-	-	-	250
8% Debentures Due 2009	513	(4)	-	-	-	509
6.5% Debentures Due 2010	882	(55)	-	-	-	827
10.5% Debentures Due 2008	2,999	(627)	-	-	-	2,372
6.40% Debentures Due 2012	122	(10)	-	-	-	112
7.25% Debentures Due 2013	244	(8)	-	-	-	236
7.25% Debentures Due 2014	157,139	(8,929)	-	-	-	148,210
Exercise of unit appreciation rights and other	658	-	-	-	-	658
Issue costs	(25,906)	-	-	-	-	(25,906)
Foreign currency translation adjustment	-	-	-	-	(243,632)	(243,632)
Net income	-	-	(25,676)	-	-	(25,676)
Distributions and distribution reinvestment plan	178,489	-	-	(610,280)	-	(431,791)
At December 31, 2007	**$3,736,080**	**$ 39,537**	**$ 246,865**	**$ (1,340,349)**	**$ (196,759)**	**$ 2,485,374**

See accompanying Notes to these Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31

(thousands of Canadian dollars)

	2007	2006
Cash provided by (used in)		
Operating Activities		
Net (loss) income for the year	**$ (25,676)**	$ 136,046
Items not requiring cash		
Depletion, depreciation, amortization and accretion	**526,741**	429,470
Unrealized foreign exchange loss (gain)	**(55,725)**	23,956
Non-cash interest expense	**7,534**	1,577
Amortization of deferred finance charges	**4,509**	8,432
Unrealized loss (gain) on risk management contracts *[Note 18]*	**147,781**	(52,179)
Future income tax expense (recovery)	**65,802**	(2,300)
Non-controlling interest	**-**	(65)
Unit based compensation expense	**743**	775
Amortization of office lease premiums and deferred rent expense	**139**	(161)
Employee benefit obligation	**(61)**	(328)
Settlement of asset retirement obligations *[Note 10]*	**(13,090)**	(9,186)
Change in non-cash working capital	**(17,384)**	(28,152)
	641,313	507,885
Financing Activities		
Issue of Trust Units, net of issue costs	**354,549**	463,160
Issue of convertible debentures, net of issue costs *[Note 12]*	**220,488**	363,742
Redemption of exchangeable shares	**-**	(1,022)
Bank borrowings (repayments), net *[Note 11]*	**(291,947)**	1,452,138
Financing costs	**(273)**	(13,071)
Cash distributions	**(433,699)**	(273,391)
Change in non-cash working capital	**(1,223)**	(12,604)
	(152,105)	1,978,952
Investing Activities		
Additions to property, plant and equipment	**(344,785)**	(398,292)
Business acquisitions	**(170,782)**	(2,044,640)
Property acquisitions	**(27,943)**	(65,773)
Property dispositions	**60,569**	20,856
Increase in other non-current assets	**-**	(165)
Change in non-cash working capital	**(14,710)**	10,886
	(497,651)	(2,477,128)
Change in cash and cash equivalents	**(8,443)**	9,709
Effect of exchange rate changes on cash	**(1,563)**	297
Cash and cash equivalents, beginning of year	**10,006**	-
Cash and cash equivalents, end of year	**$ -**	$ 10,006
Interest paid	**$ 130,990**	$ 53,434
Large corporation tax and other tax paid	**$ 442**	$ 862

See accompanying notes to these consolidated financial statements.

1. Structure of the 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 and is governed pursuant to the Amended and Restated Trust Indenture dated February 3, 2006 between Harvest Operations Corp. ("Harvest Operations"), a wholly owned subsidiary and manager of the Trust, and Valiant Trust Company as Trustee (the "Trust Indenture"). The purpose of the Trust is to indirectly exploit, develop and hold interests in petroleum and natural gas properties and refining and marketing assets through investments in the securities of its subsidiaries and net profits interests in petroleum and natural gas properties. The beneficiaries of the Trust are the holders of its Trust Units (the "Unitholders") who receive monthly distributions from the Trust's net cash flow from its various investments after 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 to comply with the mutual fund trust requirements of the Income Tax Act (Canada). The Trusts' activities are limited to holding and administering permitted investments and making distributions to its Unitholders.

The business of the Trust is carried on by Harvest Operations and other operating subsidiaries of the Trust, including North Atlantic Refining Limited Partnership. The activities of Harvest Operations and the Trust's subsidiaries are financed through interest bearing notes from the Trust, net profit interests issued to the Trust, and third party debt such as the bank debt and the $7^{7/8}$% senior notes.

The net profit interests are determined pursuant to the terms of each respective net profit interest agreement. The Trust is entitled to net profit interests 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. Under the terms of the net profits interests agreements, deductible expenditures may include discretionary amounts to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of the operating subsidiaries.

References to "Harvest" refers to the Trust on a consolidated basis. References to "North Atlantic" refers to North Atlantic Refining General Partnership and it subsidiaries, all of which are 100% owned by Harvest.

2. Significant Accounting Policies

These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These principles differ in certain respects from accounting principles generally accepted in the United States of America ("U.S. GAAP") and to the extent that the differences materially affect Harvest, they are described in Note 21.

(a) Consolidation
These consolidated financial statements include the accounts of Harvest and its subsidiaries. All inter-entity transactions and balances have been eliminated upon consolidation.

(b) Use of Estimates
The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Specifically, amounts recorded for depletion, depreciation, amortization and accretion expense, asset retirement obligations, fair value of risk management contracts, employee future benefits and amounts used in the impairment tests for intangible assets, goodwill, inventory and property, plant and equipment are based on estimates. These estimates include petroleum and natural gas reserves, future petroleum and natural gas prices, future interest rates and future costs required to develop those reserves as well as other fair value assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be material.

(c) ***Revenue Recognition***

Revenues associated with the sale of crude petroleum, natural gas, natural gas liquids and refined products are recognized when title passes to customers and payment has either been received or collection is reasonably certain. Concurrent with the recognition of revenue from the sale of refined products and included in purchased products for resale and processing are associated transportation charges. Revenues for retail services are recorded when the services are provided.

The sales price of residential home heating fuels and automotive gasoline and diesel within the Province of Newfoundland and Labrador is subject to regulation under the Petroleum Products Act. The Petroleum Products Pricing Commissioner sets the maximum wholesale and retail prices that a wholesaler and a retailer may charge and sets the maximum mark-up between the wholesale price to the retailer and the retail price to the consumer. Prices are set biweekly using a price adjustment formula based on an allowable premium above Platt's with an interruption formula. The full effect of rate regulation is reflected in the product sales revenue as recorded by Harvest.

(d) ***Inventories***

Inventories are carried at the lower of cost or net realizable value. The costs of in process inventory are determined using the weighted average cost method. The costs of purchased goods and petroleum products held for resale are determined under the first in, first out method. The costs of parts and supplies inventories are determined under the average cost method.

(e) ***Joint Venture and Partnership Accounting***

The subsidiaries of Harvest conduct substantially all of their petroleum and natural gas production activities through joint ventures and through partnerships. The consolidated financial statements reflect only Harvest's proportionate interest in such activities.

(f) ***Property, Plant, and Equipment***

Petroleum and Natural Gas

Harvest follows the full cost method of accounting for its petroleum and natural gas activities. All costs of acquiring petroleum and natural gas properties, whether productive or unproductive, related development costs, and overhead charges directly related to these activities, are capitalized and accumulated in one cost centre. Maintenance and repair costs that do not extend or enhance the recoverable reserves are charged against income.

Proceeds from the sale of petroleum and natural gas properties are applied against capital costs. Gains and losses are not recognized on the disposition of petroleum and natural gas properties unless that disposition would alter the rate of depletion and depreciation by 20% or more.

Provision for depletion and depreciation of petroleum and natural gas assets is calculated using the unit-of-production method, based on proved reserves net of royalties as evaluated by independent petroleum engineers. The cost basis used for the depletion and depreciation provision is the capitalized costs of petroleum and natural gas assets plus the estimated future development costs of proved undeveloped reserves. Reserves are converted to equivalent units on the basis of six thousand cubic feet of natural gas to one barrel of petroleum, reflecting the approximate relative energy content.

Harvest places a limit on the aggregate carrying amount of property, plant and equipment associated with petroleum and natural gas activities which may be amortized to depletion and depreciation in future periods. Impairment is recognized when the carrying amount of the petroleum and natural gas assets exceeds the sum of the undiscounted future cash flows expected from the proved reserves.

To recognize impairment, Harvest would then measure the amount of impairment by comparing the carrying amounts of the petroleum and natural gas assets to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves using Harvest's risk-free discount rate. Any excess carrying amount above the net present value of Harvest's future cash flows would be a permanent impairment and reflected as a charge to net income for the period.

Cash flows are calculated based on future price estimates, adjusted for Harvest's contractual arrangements related to pricing and quality differentials.

The cost of unproved properties is excluded from the impairment test calculation described above and subject to a separate impairment test. An impairment of unproved properties is recognized when the cost base exceeds the fair value determined by a reference to market prices, historical experience or a third party independent evaluator. There were no impairment write downs for petroleum and natural gas assets for the years ended December 31, 2007 and 2006.

Refining and Marketing

Property, plant and equipment related to the refining assets are recorded at cost. Depreciation of recorded cost less salvage value is provided on a straight-line basis over the estimated useful life of the assets as set out below. Any gains or losses on disposal of individual assets are recognized in the year of disposal.

Asset	**Period**
Refining and production plant:	
Processing equipment	5 – 25 years
Structures	15 – 20 years
Catalysts	2 – 5 years
Tugs	25 years
Vehicles	2-5 years

Maintenance and repair costs including major maintenance activities, are expensed as incurred. Improvements that increase or prolong the service life or capacity of an asset are capitalized.

Property, plant and equipment related to refining assets are tested for recovery whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Property, plant and equipment related to refining assets are not recoverable if their carrying amounts exceed the sum of the undiscounted cash flows expected to result from their use and eventual disposition. If property, plant and equipment related to refining assets are not recoverable, an impairment loss is recognized in an amount by which their carrying amount exceed their fair value, with fair value determined based on discounted estimated net cash flows. There was no impairment write-down for refining assets for the years ended December 31, 2007 and 2006.

(g) Goodwill and Other Intangible assets

Goodwill is recognized when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Goodwill is carried at cost less impairment and is not amortized. The carrying amount of goodwill is assessed for impairment annually at year-end, or more frequently if events occur that could result in an impairment. The goodwill impairment test is a two step test. In the first step, the carrying amount of the assets and liabilities, including goodwill, is compared to the fair value of the reporting unit. The fair value of a reporting unit is determined by calculating the present value of the expected future cash flows from the reporting unit. If the fair value is less than the carrying amount of the reporting unit, a potential impairment of goodwill may exist requiring the second test to be performed. Impairment is measured by allocating the fair value of the reporting unit, as determined in the first test, over the identifiable assets and liabilities. The excess of the fair value of the reporting unit over the fair value of the identifiable assets and liabilities represents the fair value of goodwill. The excess of the book value of goodwill over this implied fair value is then recognized as an impairment and charged to income in the period in which it occurs. There were no impairment write-downs for each of the years ended December 31, 2007 and 2006.

Intangible assets with determinable useful lives are amortized using the straight line method over the estimated lives of the assets, which range from 5–20 years. The amortization methods and estimated service lives are reviewed annually. The carrying amounts of intangible assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable. Intangibles are not recoverable if their carrying amounts exceed the sum of the undiscounted cash flows expected to result from their use and eventual disposition. If intangibles are not recoverable, an impairment loss is recognized in an amount by which their carrying amount exceeds their fair value, with fair value determined based on discounted estimated net cash flows. There was no impairment write-down for the years ended December 31, 2007 and 2006.

(h) Asset Retirement Obligations

Harvest recognizes the fair value of any asset retirement obligations as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and normal use of the assets. Harvest uses a credit-adjusted risk free discount rate to estimate this fair value. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and depleted and depreciated using the method described under "Property, Plant and Equipment". Subsequent to the initial measurement of the asset retirement obligation, the obligation is adjusted at the end of each subsequent period to reflect the passage of time and changes in the timing and amount of estimated future cash flows underlying the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

(i) Income Taxes

Under the Income Tax Act (Canada) the Trust and its trust subsidiary entities are taxable only on income that is not distributed or distributable to their Unitholders. As both the Trust and its Trust subsidiaries distribute all of their taxable income to their respective Unitholders pursuant to the requirements of their trust indentures, neither the Trust nor its trust subsidiaries are currently subject to income tax. However, pursuant to newly enacted legislation in 2007, the Trust and its flow-through subsidiaries will become subject to a distribution tax beginning in 2011, provided that Harvest maintains its current structure. Harvest now makes provisions for future income taxes to reflect this new legislation.

Harvest follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the corporate subsidiaries and their respective tax bases, using enacted or substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. A valuation allowance is recorded against any future income tax asset if it is more likely than not that the asset will not be realized.

(j) Unit-based Compensation

Harvest determines compensation expense for the Trust Unit Rights Incentive Plan ("Trust Unit Incentive Plan") and the Unit Award Incentive Plan ("Unit Award Incentive Plan") by estimating the intrinsic value of the rights at each period end and recognizing the amount in income over the vesting period. After the rights have vested, further changes in the intrinsic value are recognized in income in the period of change.

The intrinsic value is the difference between the market value of the Units and the exercise price of the right in the case of the Trust Unit Incentive Plan, and in the case of the Unit Award Incentive Plan the market value of the Units represents the intrinsic value of the Award. Under the Trust Unit Incentive Plan, the intrinsic value method is used as participants in the plan have the option to either purchase the Units at the exercise price or to receive a cash payment or Trust Unit equivalent, equal to the excess of the market value of the Units over the exercise price. Under the Unit Award Incentive Plan participants have the option upon exercise to receive a cash payment or Trust Unit equivalent, equal to the value of awards outstanding, which is equivalent to the market value of the Units.

(l) Employee Future Benefits

North Atlantic maintains defined benefit and defined contribution plans and provides certain post-retirement health care benefits, which cover the majority of its employees and their surviving spouses.

(i) Defined Contribution Plan

Under the defined contribution plan, the annual contribution of each participating employee's pensionable earnings is as follows:

Employee category	2006
Permanent	**5.0%**
Part-time	**2.5%**

The contributions associated with the defined contribution plan is expensed as incurred.

(ii) Defined Benefit Plans

The cost of providing the defined benefits and other post-retirement benefits is actuarially determined based upon an independent actuarial valuation using management's best estimates of discount rates, rate of return on plan assets, rate of compensation increase, retirement ages of employees, and expected health care costs. The cost of pensions earned by employees is actuarially determined using the projected benefit method prorated on credited service. Funding of the defined benefit pension plans complies with Canadian federal and provincial regulations, and requires contributions to the plans be made based on independent actuarial valuation. Pension plan assets are measured at fair values with the difference between the fair value of the plan assets and the total employee benefit obligation recorded on the balance sheet. For the purpose of calculating the expected return on assets, the fair value of the plan assets is used.

The defined benefit plans provide benefits based on length of service and the best five years of the last ten years' average earnings. There is no recognition or amortization of actuarial gains or losses less than 10% of the greater of the accrued benefit obligations and the fair value of plan assets for the defined benefit pension plans. Actuarial gains and losses over 10% are amortized on a straight-line basis over the average remaining service period of the plan participants. Actuarial gains or losses related to the other post-retirements benefits are recognized in income immediately. Past service costs are amortized on a straight-line basis over the expected average remaining service life of plan participants.

(m) Currency Translation

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

Harvest's investment in a subsidiary with a functional currency denominated in a currency other than the Canadian dollars is translated using the current rate method as the subsidiary is considered a self-sustaining operation. Gains and losses resulting from this translation are recorded in the cumulative translation adjustment in unitholders' equity.

(n) Rate Regulation

The sales price of residential home heating fuels and automotive gasoline and diesel within the Province of Newfoundland and Labrador is subject to regulation under the Petroleum Products Act. The Petroleum Products Pricing Commissioner sets the maximum mark-up between the wholesale price to the retailer and the retail price to the consumer. The full effect of rate regulation is reflected in the product sales revenue as recorded.

3. Change in Accounting Policy

Financial Instruments and Comprehensive Income

Effective January 1, 2007, Harvest adopted three new and revised Canadian accounting standards as issued by the Canadian Institute of Chartered Accountants respecting "Financial Instruments – Recognition and Measurement", "Financial Instruments – Presentation and Disclosure" and "Comprehensive Income".

<u>Financial Instruments</u>

The revised standard on financial instruments provides new guidance on how to recognize and measure financial instruments. It requires all financial instruments to be recorded at fair value when initially recognized. Subsequent measurement is either at fair value or amortized cost, depending on the classification of the financial instrument. Financial assets and liabilities that are held-for-trading are measured at fair value with changes in those fair values recognized in net income. Available-for-sale financial assets are measured at fair value with unrealized gains or losses recognized in other comprehensive income. Held-to-maturity assets, loans and receivables and other liabilities are all measured at amortized cost with any related expenses or income recognized in net income. Price risk management contracts are classified as held-for-trading and are measured at fair value at initial recognition and at subsequent measurement dates. Any derivatives embedded in other financial or non-financial contracts that were entered into on or after January 1, 2001 must also be measured at fair value and recorded in the financial statements if the embedded derivative is not closely related to the host contract. Fair value of financial instruments is based on market prices where available, otherwise it is calculated as the net present value of expected future cash flows. For those items measured at amortized cost, interest expense is calculated using an effective interest rate that accretes any discount or premium over the life of the instrument so that the carrying value equals the face value at maturity.

Harvest does not have any financial assets classified as available-for-sale or held-to-maturity. The only items on Harvest's balance sheet that are classified as held-for-trading and subsequently measured at fair value are cash and our price risk management contracts. The remainder of the financial instruments are measured at amortized cost. As well, there are no significant embedded derivatives that need to be recorded in the financial statements.

Transaction costs relating to financial instruments classified as held for trading are expensed in net income in the period that they are incurred. Harvest has elected to add all other transaction costs that are directly attributable to the acquisition or issue of a financial asset or liability to the amount of the financial asset or liability that is recorded on initial recognition.

The transitional provisions of the financial instruments standard require retrospective adoption without restatement of prior period financial statements. The provisions also require all financial instruments to be remeasured using the criteria of the new standard and any change in the previous carrying amount to be recognized as an adjustment to retained earnings on January 1, 2007. As our price risk management contracts were already measured at fair value, the most significant change for Harvest was reclassifying the deferred charges relating to our senior notes and convertible debentures and netting these amounts against the respective liability. These charges are then amortized to income using an effective interest rate. The effect of applying this new standard on January 1, 2007 was to reduce the carrying value of the following accounts as indicated with an offsetting reduction to deferred charges:

Deferred charges	$	(25,067)
7 $^{7/8}$% Senior notes		(9,522)
Convertible debentures		(16,882)
Unitholders' capital		(49)
Accumulated income		1,386

See Note 18 for the additional presentation and disclosure requirements for Financial Instruments.

Other Comprehensive Income

The new standards introduce the concept of comprehensive income, which consists of net income and other comprehensive income. Other comprehensive income represents changes in Unitholders' equity during a period arising from transactions and other events with non-owner sources. The transitional provisions of this section require that the comparative statements are restated to reflect the application of this standard only on certain items.

For Harvest, the only such item is the unrealized foreign currency translation gains or losses arising from our downstream operations, which is considered a self-sustaining operation with a U.S. dollar functional currency. As the cumulative translation adjustment was presented as a separate component of Unitholders' equity already, this restatement simply required the cumulative translation adjustment to be reclassified to accumulated other comprehensive income on the balance sheet and statement of Unitholders' equity.

Future Accounting Changes

The AcSB issued new accounting standards on December 1, 2006 that require increased disclosure on financial instruments, particularly with regard to the nature and extent of risks arising from financial instruments and how the entity manages those risks. This standard has an implementation date for annual and interim financial statements beginning on or after October 1, 2007.

Also on December 1, 2006, the AcSB issued a new standard regarding Capital Disclosure requiring the disclosure of information about an entity's objectives, policies and processes for managing capital; quantitative data about what the entity regards as capital; whether the entity has complied with any externally imposed capital requirements; and if it has not complied, the consequences of such non-compliance. This standard also has an implementation date for annual and interim financial statements beginning on or after October 1, 2007.

In June 2007, the AcSB issued section 3031, Inventories, which replaces the existing inventories standard. This new standard provides additional guidance with respect to the measurement and disclosure requirements for inventories, requiring inventories to be valued at the lower of cost and net realizable value. This standard is to be adopted for fiscal years beginning on or after January 1, 2008. We do not expect the adoption of this section to have a material impact on our net income or financial position.

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062 Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. The new Section will be effective on January 1, 2009. Section 3062 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. We are currently evaluating the impact of the adoption of this new Section, however do not expect a material impact on our Consolidated Financial Statements.

4. Business Acquisitions

(a) Grand Petroleum Inc. ("Grand")

Pursuant to its cash offer of $3.84 for each issued and outstanding common share of Grand, Harvest acquired control of Grand with its acquisition of 21,310,419 Grand common shares for cash consideration of $81.8 million on July 26, 2007. Subsequent to this acquisition of 74.6% of the issued and outstanding common shares of Grand, Harvest acquired the remaining 7,251,604 common shares of Grand for an additional $27.8 million by extending its offer to purchase to August 9, 2007 and thereafter pursuant to the compulsory acquisition provisions of the *Business Corporations Act (Alberta)*. The aggregate consideration for the Grand acquisition consists of the following:

		Amount
Cash paid	$	109,678
Assumption of bank debt		28,798
Acquisition costs		785
	$	139,261

This acquisition has been accounted for using the purchase method, whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregate consideration over the fair value of the identifiable net assets allocated to goodwill. As of the acquisition date, Grand's operating results have been included in Harvest's revenues, expenses and capital spending. The following summarizes the allocation of the aggregate consideration for the Grand acquisition.

		Amount
Net working capital	$	(3,451)
Property, plant and equipment		147,420
Goodwill		20,546
Asset retirement obligation		(4,416)
Future income tax		(20,838)
	$	139,261

Amendments may be made to the purchase equation as the cost estimates and balances are finalized.

(b) Private petroleum and natural gas corporation

On March 1, 2007, Harvest acquired all of the issued and outstanding shares of a private petroleum and natural gas corporation for $30.6 million net of working capital adjustments and transaction costs. The results of operations of this acquisition have been included in the consolidated financial statements since its acquisition date. An officer of Harvest was a director of this private corporation and received proceeds that are considered to be insignificant to both the officer and Harvest.

(c) North Atlantic Refining Limited

On October 19, 2006, Harvest acquired all of the issued and outstanding shares of North Atlantic Refining Limited for $1.6 billion plus certain working capital and other adjustments. The principal asset of North Atlantic Refining Limited is a medium gravity, sour-crude hydrocracking refinery. North Atlantic Refining Limited also operates a marketing division which includes gas stations, a retail heating fuels business and other ancillary services. The results of operations of North Atlantic have been included in the consolidated financial statements since its acquisition on October 19, 2006.

The aggregate consideration for the acquisition of North Atlantic consists of the following:

Consideration for the acquisition:		Amount
Cash paid	$	1,592,793
Acquisition costs		4,331
	$	1,597,124

This transaction has been accounted for using the purchase method whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregated consideration over the fair value of the identifiable net assets allocated to goodwill. These amounts are estimates made by management based on currently available information. The following summarizes the aggregate consideration for the North Atlantic acquisition:

		Amount
Net working capital (including cash of $22,464)	$	2,863
Inventory		36,137
Property, plant and equipment		1,254,696
Intangible assets (Note 6)		111,977
Long-term receivables		2,729
Goodwill		200,925
Funding deficiency of pension and other benefit plans		(12,203)
	$	1,597,124

During 2007 the acquisition costs were reduced by $0.7 million and net working capital was increased by $2.9 million, with a corresponding decrease in goodwill, as certain accrued liabilities that were estimated at the time of purchase did not materialize subsequent to the acquisition.

(d) Birchill Energy Limited ("Birchill")

On July 26, 2006, Harvest signed a binding agreement to purchase all of the issued and outstanding shares of Birchill on August 15, 2006 for $446.8 million net of working capital adjustments and transaction costs. The results of operations of Birchill have been included in the consolidated financial statements since the time of effective control, July 26, 2006.

The aggregate consideration for the acquisition of Birchill consists of the following:

Consideration for the acquisition:		Amount
Cash paid, net of expected working capital recoveries	$	447,511
Acquisition costs		267
	$	447,778

This transaction has been accounted for using the purchase method whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregate consideration over the fair value of the identifiable net assets allocated to goodwill. The following summarizes the allocation of the aggregate consideration for the Birchill acquisition.

Consideration for the acquisition:		Amount
Net working capital deficiency (including nil cash)	$	(14,755)
Property, plant and equipment		463,752
Asset retirement obligation		(1,219)
	$	447,778

During 2007 the cash paid for Birchill was increased by $1.9 million while the acquisition costs were decreased by $1.0 million with the corresponding net increase of $0.9 million reflected in property, plant and equipment. The increase in cash paid is due to additional assets that could not be valued at the time of acquisition and were therefore subsequently valued and settled, while the reduction in acquisition costs relates to certain accrued liabilities that were estimated at the time of purchase and did not materialize subsequent to the acquisition.

(e) Viking Energy Royalty Trust ("Viking")

On February 3, 2006, the unitholders of Harvest and Viking voted to approve a resolution to effect the Plan of Arrangement (the "Plan of Arrangement") by which unitholders of Viking received 0.25 Harvest Trust Units for every Viking Trust Unit held, and Harvest acquired all of the assets and assumed all of the liabilities of Viking for total consideration of approximately $1,638.1 million plus assumption of debt. This amount consisted of the issuance of 46,040,788 Trust Units [Note 13(b)] at an ascribed value of $35.58 per Trust Unit, based on the weighted average trading price of the Harvest Trust Units before and after the announcement date of November 28, 2005. Pursuant to the terms and conditions of Vikings' convertible debenture indenture, Harvest's acquisition of Viking's net assets resulted in Harvest assuming the obligations of Viking's convertible debentures, including the adjustment of the conversion ratio to reflect the 0.25 Harvest Trust Unit for each Viking Trust Unit exchange ratio.

The aggregate consideration for the acquisition of Viking consists of the following:

Consideration for the acquisition:		Amount
Ascribed value of Trust Units issued	$	1,638,131
Bank debt assumed		106,247
Convertible debentures assumed		-
Debt component		202,232
Equity component		24,123
Acquisition costs		4,600
	$	1,975,333

This transaction has been accounted for using the purchase method whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregate consideration over the fair value of the identifiable net assets allocated to goodwill. The following summarizes the allocation of the aggregate consideration for the Viking acquisition.

Allocation of purchase price:		Amount
Net working capital deficiency (including nil cash)	$	(31,297)
Property, plant and equipment		1,455,000
Fair value deficiency of risk management contracts		(1,224)
Fair value of office lease (Note 6)		931
Goodwill		612,416
Asset retirement obligation		(60,493)
	$	1,975,333

Effective February 3, 2006, the results of Viking have been included in the consolidated financial statements.

5. Inventories

		December 31, 2007		December 31, 2006
Petroleum products	**$**	**55,036**	$	19,513
Parts and supplies		**3,898**		4,279
Total inventories, net	**$**	**58,934**	$	23,792

6. Property, Plant and Equipment

	December 31, 2007			December 31, 2006		
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total
Cost	**$ 4,247,819**	**$ 1,164,310**	**$ 5,412,129**	$ 3,801,054	$ 1,320,698	$ 5,121,752
Accumulated depletion and depreciation	**(1,142,345)**	**(72,277)**	**(1,214,622)**	(706,540)	(14,660)	(721,200)
Net book value	**$ 3,105,474**	**$ 1,092,033**	**$ 4,197,507**	$ 3,094,514	$ 1,306,038	$ 4,400,552

General and administrative costs of $9.2 million (2006 – $12.1 million) have been capitalized during the year ended December 31, 2007, of which $0.6 million (2006 - $3.0 million) relate to the Trust Unit Incentive Plan and the Unit award incentive plan.

All costs, except those associated with undeveloped properties, major spare parts inventory and assets under construction, are subject to depletion and depreciation at December 31, 2007 including future development costs of $325.4 million (2006 – $289.2 million). No amounts for undeveloped properties were excluded from the asset base subject to depletion for the years ended December 31, 2007 and 2006. Downstream major parts inventory of $6.1 million were excluded from the asset base subject to depreciation at December 31, 2007 (2006 - $6.7 million). Downstream assets under construction of $7.4 million were excluded from the asset base subject to depreciation at December 31, 2007 (2006 - $5.5 million).

The petroleum and natural gas future prices used in the impairment test for petroleum and natural gas assets were obtained from third party engineers and were adjusted for contractual arrangements relating to pricing and quality differentials specific to Harvest. Based on these assumptions, the undiscounted future net revenue from Harvest's proved reserves exceed the carrying amount of its petroleum and natural gas assets as at December 31, 2007 and 2006, and therefore no impairment was recorded in either of the periods ended on these dates.

Benchmark prices and U.S.$/Cdn.$ exchange rate assumptions reflected in the impairment test as at December 31, 2007 were as follows:

Year	**WTI Oil[(1)] (US$/barrel)**	**Foreign Exchange Rate**	**Edmonton Light Crude Oil[(1)] (CDN$ barrel)**	**AECO Gas[(1)] (CDN$/Gigajoule)**
2008	90.00	1.00	89.00	6.45
2009	86.70	1.00	85.70	7.00
2010	83.20	1.00	82.20	7.00
2011	79.60	1.00	78.50	7.00
2012	78.50	1.00	77.40	7.10
Thereafter (escalation)	2%	0%	2%	2%

[(1)] Actual prices used in the impairment test were adjusted for commodity price differentials specific to Harvest

7. Intangible Assets

	December 31, 2007			December 31, 2006		
	Cost	**Accumulated Amortization**	**Net book value**	Cost	Accumulated Amortization	Net book value
Engineering drawings	**$ 88,227**	**$ 5,330**	**$ 82,897**	$ 103,721	$ 1,080	$ 102,641
Marketing contracts	**6,136**	**1,099**	**5,037**	7,214	105	7,109
Customer lists	**3,714**	**449**	**3,265**	4,368	92	4,276
Fair value of office lease	**931**	**428**	**503**	931	205	726
Financing costs	**12,113**	**8,740**	**3,373**	11,840	4,230	7,610
Total	**$ 111,121**	**$ 16,046**	**$ 95,075**	$ 128,074	$ 5,712	$ 122,362

8. Other Non-Current Assets

	December 31, 2007	December 31, 2006
Deferred charges, net of amortization *[Note 3]*	**$ -**	$ 23,659
Discount on senior notes, net of amortization *[Note 3]*	**-**	1,408
Total	**$ -**	**$** 25,067

9. Accounts Payable and Accrued Liabilities

		December 31, 2007		December 31, 2006
Trade accounts payable	**$**	**100,265**	$	111,837
Accrued interest		**15,779**		14,367
Trust Unit Incentive Plan and Unit Award Incentive Plan *[Note 15]*		**7,218**		6,442
Other accrued liabilities		**146,981**		161,936
Total	**$**	**270,243**	$	294,582

10. Asset Retirement Obligation

Harvest's asset retirement obligations result from its net ownership interest in petroleum and natural gas assets including well sites, gathering systems and processing facilities and the estimated costs and timing to reclaim and abandon them. Harvest estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations to be approximately $1,003 million which will be incurred between 2008 and 2057. The majority of the costs will be incurred between 2015 and 2040. A credit-adjusted risk-free discount rate of 8% - 10% and inflation rate of approximately 2% were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

		December 31, 2007		December 31, 2006
Balance, beginning of year	**$**	**202,480**	$	110,693
Incurred on acquisition of a private corporation		**1,629**		-
Incurred on acquisition of Grand		**4,416**		-
Incurred on acquisition of Viking		**-**		60,493
Incurred on acquisition of Birchill		**-**		1,219
Liabilities incurred		**9,553**		2,763
Revision of estimates		**(6,088)**		20,544
Liabilities settled through disposition		**(3,708)**		-
Liabilities settled		**(13,090)**		(9,186)
Accretion expense		**18,337**		15,954
Balance, end of year	**$**	**213,529**	$	202,480

Harvest has undiscounted asset retirement obligations of approximately $14.7 million relating to the refining and marketing assets. The fair value of this obligation cannot be reasonably determined because the assets currently have an indeterminate life.

11. Bank Loan

At December 31, 2007, Harvest had $1,279.5 million drawn under its $1.6 billion Three Year Extendible Revolving Credit Facility ("Credit Facility"). At December 31, 2006, Harvest had $1,306.0 million drawn under the Credit Facility, of which $763.0 million was payable in U.S. dollars, and $289.7 million drawn under its $350 million Senior Secured Bridge Facility.

The Credit Facility was established on February 3, 2006 and subsequently amended on October 19, 2006 to accommodate the purchase of North Atlantic. This amendment increased the borrowing capacity to $1.4 billion and established a $350 million Senior Secured Bridge Facility. The maturity date of this facility was March 31, 2009, but could be extended on an annual basis for an additional 364 days with the consent of the lenders. The credit facility is secured by a $2.5 billion first floating charge over all of the assets of Harvest's operating subsidiaries plus a first mortgage security interest on the refinery assets of North Atlantic. Amounts borrowed under this facility bear interest at a floating rate based on bankers' acceptances plus a range of 65 to 115 basis points depending on Harvest's ratio of senior debt (excluding convertible debentures) to its earnings before interest, taxes, depletion, amortization and other non-cash amounts ("EBITDA"). An additional fee of 15 basis points was applicable so long as the Senior Unsecured Bridge Facility was outstanding. Availability under this facility is subject to the following quarterly financial covenants:

Senior debt to EBITDA	3.0 to 1.0 or less
Total debt to EBITDA	3.5 to 1.0 or less
Senior debt to Capitalization	50% or less
Total debt to Capitalization	55% or less

The $350 million Senior Secured Bridge Facility provided Harvest with a single draw on this facility within five days of the closing of its acquisition of North Atlantic and required repayments equivalent to the net proceeds from an issuance of equity or equity like securities including convertible debentures and, in all events, repayment in full within 18 months of the initial draw.

On February 1, 2007, Harvest issued 6,146,750 Trust Units and 200,000 convertible debentures for total net proceeds of $328.6 million which was used to fully repay the remaining $289.7 million outstanding on the Senior Secured Bridge Facility with the remainder applied to the Credit Facility.

On May 7, 2007, Harvest and its lenders amended the Credit Facility to increase the aggregate commitment amount from $1.4 billion to $1.6 billion and extend the maturity date of the facility from March 31, 2009 to April 30, 2010 with respect to $1,535 million of the aggregate commitment amount. Effective May 7, 2007, the Credit Facility consists of $1,535 million of commitments with a maturity date of April 30, 2010 and $65 million of commitments with a maturity date of March 31, 2009.

On October 1, 2007, two of Harvest’s existing lenders agreed to assume $50 million of the $65 million commitment to mature on March 31, 2009 and concurrently extended the maturity to April 30, 2010. On November 1, 2007, another of Harvest’s existing lenders agreed to assume the remaining $15 million of credit commitments to mature on March 31, 2009 and similarly extended the maturity to April 30, 2010. Subsequent to these reassignments, the entire $1.6 billion of the Credit Facility matures on April 30, 2010.

On October 19, 2006, North Atlantic entered into an amended and restated credit agreement that provided for a $10 million demand operating line of credit to finance its receivables and inventory in the Province of Newfoundland and Labrador as well as support periodic cash management market transactions. This facility is secured by a guarantee from Harvest Operations Corp. with amounts borrowed bearing interest at the bank's prime lending rate.

For the year ended December 31, 2007 Harvest paid interest at an average rate of 5.28% (2006 – 4.86%) and 6.08% (2006 – 6. 07%) for the Canadian and U.S amounts drawn, respectively.

12. Convertible Debentures

Harvest has seven series of convertible unsecured subordinated debentures outstanding. Interest on the debentures is payable semi-annually in arrears in equal installments on dates prescribed by each series. The 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 Harvest for redemption. The conversion price per Trust Unit is specified for each series and may be supplemented with a cash payment for accrued interest and in lieu of any fractional Trust Units resulting from the conversion.

The debentures may be redeemed by Harvest at its option in whole or in part prior to their respective maturity dates. The redemption price for the first redemption period is at a price equal to $1,050 per debenture and at $1,025 per debenture during the second redemption period. Any redemption will include accrued and unpaid interest at such time. Harvest may elect to settle the principal due at maturity or on redemption and periodic interest payments in the form of Trust Units at a price equal to 95% of the weighted average trading price for the preceding 20 consecutive trading days, 5 days prior to settlement date.

The following is a summary of the seven series of convertible debentures:

Series	Conversion price / Trust Unit	Maturity	First redemption period	Second redemption period
9% Debenture Due 2009	$ 13.85	May 31, 2009	Jun. 1/07-May 31/08	Jun. 1/08-May. 30/09
8% Debenture Due 2009	$ 16.07	Sept. 30, 2009	Oct. 1/07-Sept. 30/08	Oct. 1/08-Sept. 29/09
6.5% Debenture Due 2010	$ 31.00	Dec. 31, 2010	Jan. 1/09-Dec. 31/09	Jan. 1/10-Dec. 30/10
10.5% Debenture Due 2008	$ 29.00	Jan. 31, 2008	Feb. 1/06-Jan. 31/07	Feb. 1/07-Jan. 30/08
6.40% Debenture Due 2012[(1)]	$ 46.00	Oct. 31, 2012	Nov. 1/08-Oct. 31/09	Nov. 1/09-Oct. 31/10
7.25% Debenture Due 2013[(1)]	$ 32.20	Sept. 30, 2013	Oct. 1/09-Sept. 30/10	Oct. 1/10-Sept. 30/11
7.25% Debenture Due 2014[(1)]	$ 27.25	Feb. 28, 2014	Mar. 1/10-Feb. 28/11	Mar. 1/11-Feb. 29/12

(1) These series of convertible debentures may also be redeemed by Harvest at a price of $1,000 per debenture after the second redemption period until maturity.

The following table summarizes the face value, carrying amount and fair value of the convertible debentures:

	December 31, 2007			December 31, 2006	
	Face Value	**Carrying Amount[(1)]**	**Fair Value**	Face Value	Carrying Amount[(1)]
9% Debentures Due 2009	$ 976	$ 962	$ 1,806	$ 1,226	$ 1,226
8% Debentures Due 2009	1,728	1,692	2,022	2,239	2,229
6.5% Debentures Due 2010	37,062	34,653	35,950	37,929	35,988
10.5% Debentures Due 2008	24,258	24,273	24,258	26,621	26,824
6.40% Debentures Due 2012	174,626	168,325	148,432	174,743	167,401
7.25% Debentures Due 2013	379,256	355,145	344,895	379,500	367,843
7.25% Debentures Due 2014	73,222	66,718	65,892	-	-
	$ 691,128	**$ 651,768**	**$ 623,255**	**$ 622,258**	**$ 601,511**

(1) Excluding the equity component**.**

On January 31, 2008, the 10.5% debenture matured and Harvest elected to settle the obligation by issuing 1,116,593 Trust Units rather than settling the obligation in cash.

13. $7^{7/8}$% Senior Notes

On October 14, 2004, Harvest Operations Corp., a wholly owned subsidiary of Harvest, issued US$250 million of $7^{7/8}$% Senior Notes for cash proceeds of $311,951,000. The $7^{7/8}$% Senior Notes are unsecured, require interest payments semi-annually on April 15 and October 15 each year and mature on October 15, 2011. Prior to maturity, redemptions are permitted as follows:

- Beginning on October 15, 2007 at 103.938% of the principal amount[(1)]
- After October 15, 2008 at 103.938% of the principal amount
- After October 15, 2009 at 101.969% of the principal amount
- After October 15, 2010 at 100% of the principal amount

(1) Only permitted if necessary to prevent the Trust from being disqualified as a trust for the purpose of the Income Tax Act. Limited to 35% of the notes issued or less; otherwise 100% of the notes issued.

The $7^{7/8}$% Senior Notes contain certain covenants restricting, among other things, the sale of assets and the incurrence of additional indebtedness if such issuance would result in an interest coverage ratio, as defined, of less than 2.5 to 1. The covenants of the $7^{7/8}$% Senior Notes also restrict Harvest's secured indebtedness to an amount less than 65% of the present value of the future net revenues from its proven petroleum and natural gas reserves discounted at an annual rate of 10%. In addition, the $7^{7/8}$% Senior Notes restrict Harvest's ability to pay distributions to an amount equal to 80% of the cumulative net proceeds from the issuance of Trust Units plus the cash flows from operations, before settlement of asset retirement obligations and changes in non-cash working capital, both calculated from the date of issuance of the $7^{7/8}$% Senior Notes. An excess carryforward balance of approximately Cdn$1.5 billion exists as at December 31, 2007.

The $7^{7/8}$% Senior Notes are unconditionally guaranteed by Harvest and all of its wholly-owned subsidiaries. The fair value of the $7^{7/8}$% Senior Notes at December 31, 2007 was U.S.$232.6 million (2006 - $236.3 million).

14. Unitholders' Capital

(a) Authorized

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

(b) Number of Units Issued

	Year ended December 31, **2007**	2006
Outstanding, beginning of year	**122,096,172**	52,982,567
Issued in exchange for assets of Viking [Note 4(e)]	**-**	46,040,788
Issued for cash		
August 17, 2006	**-**	7,026,500
November 22, 2006	**-**	9,499,000
February 1, 2007	**6,146,750**	-
June 1, 2007	**7,302,500**	-
Convertible debenture conversions		
9% Debentures Due 2009	**18,047**	39,777
8% Debentures Due 2009	**31,790**	96,252
6.5% Debentures Due 2010	**27,967**	114,313
10.5% Debentures Due 2008	**81,478**	290,919
6.40% Debentures Due 2012	**2,542**	4,825
7.25% Debentures Due 2013	**7,574**	-
7.25% Debentures Due 2014	**5,753,310**	-
Exchangeable share retraction [Note 16]	**-**	184,809
Distribution reinvestment plan issuance	**6,809,987**	5,464,450
Exercise of unit appreciation rights and other	**13,053**	351,972
Outstanding, end of year	**148,291,170**	122,096,172

On August 17, 2005, Harvest implemented a premium distribution reinvestment plan. The premium distribution program enables investors to receive a cash payment equal to 102% of the regular distribution amount. The impact to Harvest is the same as the regular distribution reinvestment plan whereby it settles distributions with units rather than cash, at a discount to the current market price of the Units.

(c) Per Trust Unit Information

The following tables summarize the net income and Trust Units used in calculating income per Trust Unit:

Net income adjustments		**December 31, 2007**		December 31, 2006
Net (loss) income, basic	**$**	**(25,676)**	$	136,046
Interest on convertible debentures and other		**-**		310
Net income, diluted[(1)]	**$**	**(25,676)**	$	136,356

Weighted average Trust Units adjustments	**December 31, 2007**	December 31, 2006
Number of Units		
Weighted average Trust Units outstanding, basic	**138,440,869**	101,590,850
Effect of convertible debentures and other	**-**	322,793
Effect of Employee Unit Incentive Plans	**-**	268,518
Weighted average Trust Units outstanding, diluted[(2)]	**138,440,869**	102,182,161

(1) Net income, diluted excludes the impact of the conversions of certain of the convertible debentures of $59,238,000 for the year ended December 31, 2007 (2006 - $19,855,000), as the impact would be anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the year ended December 31, 2007 does not include the unit impact of 23,636,000 for certain of the convertible debentures (2006 – 6,980,000) and 682,000 (2006 – nil) for the Employee Unit Incentive Plans, as the impact would be anti-dilutive.

15. Employee Unit Incentive Plans

Trust Unit Rights Incentive Plan

Harvest is authorized to grant non-transferable Unit appreciation rights to directors, officers, consultants, employees and other service providers to an aggregate of a rolling maximum of 7% of the outstanding Trust Units and the number of Trust Units issuable upon the exchange of any outstanding exchangeable shares. The initial exercise price of rights granted under the plan is equal to the market price of the Trust Units at the time of grant and the maximum term of each right is five years. The rights vest equally over four years commencing on the first anniversary of the grant date. The exercise price of the rights may be reduced by an amount up to the amount of cash distributions made on the Trust Units subsequent to the date of grant of the respective right, provided that Harvest's net operating cash flow (on an annualized basis) exceeds 10% of Harvest's recorded cost of property, plant and equipment less all debt, working capital deficiency (surplus) or debt equivalent instruments, accumulated depletion, depreciation and amortization charges, asset retirement obligations, and any future income tax liability associated with such property, plant and equipment. Any portion of a distribution that does not reduce the exercise price on exercised rights is paid to the holder in a lump sum cash payment after the rights have been exercised.

Upon the exercise of unit appreciation rights the holder has the sole discretion to elect to receive cash or units. As a result, Harvest recognizes a liability on its consolidated balance sheet associated with the rights reserved under the plan. This obligation represents the difference between the market value of the Trust Units and the exercise price of the vested Unit rights outstanding under the plan. As such, an obligation of $1.4 million (2006 - $2.8 million) has been recorded in accounts payable and accrued liabilities for the graded vested portion of the 3,823,683 (2006 – 3,788,125) Trust Units outstanding under the plan at December 31, 2007. For accounting purposes, vesting is deemed to occur on a pro rata basis throughout the year, rather than at a vesting date which only occurs on the anniversary date of the grant.

The following summarizes the Trust Units reserved for issuance under the Trust Unit Incentive Plan:

	Year ended December 31, 2007			Year ended December 31, 2006		
	Unit Appreciation Rights		**Weighted Average Exercise Price**	Unit Appreciation Rights		Weighted Average Exercise Price
Outstanding beginning of year	**3,788,125**	**$**	**30.81**	1,305,143	$	19.72
Granted	**576,383**		**29.03**	3,924,300		31.92
Exercised	**(92,775)**		**21.88**	(1,039,018)		18.58
Forfeited	**(448,050)**		**31.10**	(402,300)		37.25
Outstanding before exercise price reductions	**3,823,683**		**30.74**	3,788,125		30.81
Exercise price reductions	**-**		**(5.00)**	-		(1.67)
Outstanding, end of year	**3,823,683**	**$**	**25.74**	3,788,125	$	29.14
Exercisable before exercise price reductions	**138,350**	**$**	**22.72**	266,125	$	24.18
Exercise price reductions	**-**		**(9.38)**	-		(5.37)
Exercisable, end of year	**138,350**	**$**	**13.34**	266,125	$	18.81

The following table summarizes information about Unit appreciation rights outstanding at December 31, 2007.

		Outstanding			**Exercisable**	
Exercise Price before price reductions	**Exercise Price net of price reductions**	**At December 31, 2007**	**Weighted Average Exercise Price net of price reductions(1)**	**Remaining Contractual Life (1)**	**At December 31, 2007**	**Weighted Average Exercise Price net of price reductions(1)**
$12.19-$13.15	$0.87-$2.20	6,250	$ 1.93	0.9	6,250	$ 1.93
$13.75-$14.99	$2.99-$5.13	18,250	4.95	1.5	18,250	4.95
$18.90-$25.05	$9.12-$22.58	183,650	17.51	3.2	113,850	15.31
$26.09-$28.41	$21.92-$27.35	1,669,300	22.21	4.0	-	-
$28.59-$37.56	$21.00-$32.69	1,946,233	29.81	3.4	-	-
$12.19-$37.56	$0.87-$32.69	3,823,683	$ 25.74	3.6	138,350	$ 13.34

(1) Based on weighted average Unit appreciation rights outstanding.

Unit Award Incentive Plan("Unit Award Plan")

The Unit Award Plan authorizes Harvest to grant awards of Trust Units to directors, officers, employees and consultants of Harvest and its affiliates (to an aggregate of a rolling maximum of 0.5% of the outstanding Trust Units and the number of Trust Units issuable upon the exercise of any outstanding exchangeable shares). Subject to the Board of Directors' discretion, awards vest annually over a two to four year period and, upon vesting, entitle the holder to elect to receive the number of Trust Units subject to the award or the equivalent cash amount. The number of Units to be issued is adjusted at each distribution date for an amount approximately equal to the foregone distributions. Harvest recognizes a liability on its consolidated balance sheet associated with the awards granted under the plan. This obligation represents the fair value of the vested Trust Units granted under the Unit Award Plan. As such, an obligation of $5.8 million (2006 - $3.6 million) has been recorded in accounts payable and accrued liabilities for the graded vested portion of the 348,248 (2006 – 306,699) Unit Awards outstanding under the plan at December 31, 2007. For accounting purposes, vesting is deemed to occur on a pro rata basis throughout the year, rather than at a vesting date.

Number	**December 31, 2007**	December 31, 2006
Outstanding, beginning of year	**306,699**	35,365
Granted	**56,132**	320,905
Adjusted for distributions	**48,280**	27,879
Exercised	**(37,072)**	(41,530)
Forfeitures	**(25,791)**	(35,920)
Outstanding, end of year	**348,248**	306,699
Exercisable, end of year	**168,401**	67,428

Upon closing of the Viking Plan of Arrangement all awards and rights issued under Harvest's employee unit incentive plans vested and additional rights and awards were issued under both plans.

Harvest has recognized compensation expense of $2.7 million (2006 – $9.9 million), including non cash compensation expense of $0.6 million (2006 - $0.8 million), for the year ended December 31, 2007, related to the Trust Unit Incentive Plan and the Unit Award Plan and this is reflected in general and administrative expense in the consolidated statements of income.

16. Income Taxes

The future income tax provision reflects the net tax effects of temporary differences between the carrying amounts of assets and liabilities of the Trust and their corresponding income tax bases as at that date. Changes in the temporary differences are reflected in future income tax expense or recovery.

In the second quarter of 2007, the Canadian government enacted legislation to apply a 31.5% tax to distributions from Canadian publicly traded income trusts. In the fourth quarter of 2007, the tax rate for trust distributions was reduced to 29.5% for 2011 and to 28% for 2012 and subsequent years. The new tax is not expected to apply to Harvest until 2011, as a transition period has been established for publicly traded trusts that existed prior to November 1, 2006. This portion of the Trust's future income tax liability represents its tax-effected temporary differences that it estimates will exist on January 1, 2011, pursuant to the current legislation and Harvest's current structure.

Concurrent with the tax rate reductions referred to above, further reductions in Federal corporate income tax rates were enacted. Under the legislation, Federal corporate rates will decline until 2012, resulting in an effective tax rate for the Trust's corporate entities of approximately 26%, which is the rate applied to the temporary differences in the future income tax calculation based on when these differences are expected to reverse.

The provision for future income taxes varies from the amount that would be computed by applying the relevant Canadian income tax rates to reported income before taxes as follows:

	Year ended December 31	
	2007	2006
Income before taxes	**$ 39,152**	$ 133,737
Combined Canadian Federal and Provincial statutory income tax rate	**32.7%**	35.3%
Computed income tax expense at statutory rates	**12,803**	47,209
Income earned by flow through entities	**(179,750)**	(136,452)
Loss in corporate entities	**(166,947)**	(89,243)
Increased expense (recovery) resulting from the following:		
Initial recognition of trust temporary differences	**271,705**	
Benefit of future tax deductions (recognized) not recognized	**(72,073)**	62,384
Difference between current and expected tax rates	**44,547**	10,465
Non-taxable portion of capital (gain) loss	**(20,515)**	1,789
Change in estimates	**8,860**	-
Non-deductible expenses	**225**	3,228
Non-deductible crown charges in excess of resource allowance	**-**	9,077
Future income tax expense (recovery)	**$ 65,802**	$ (2,300)

The components of the future income tax liability (asset) are as follows:

	December 31, 2007	December 31, 2006
Net book value of petroleum and natural gas assets in excess of tax pools	**$ 333,466**	$ 29,896
Net book value of intangible assets in excess of tax pools	**13,998**	-
Asset retirement obligation	**(56,066)**	(17,641)
Net unrealized losses related to risk management contracts and foreign exchange positions – current	**(38,642)**	(3,818)
Net unrealized losses related to risk management contracts and foreign exchange positions – long-term	**304**	(1,266)
Non-capital loss carry forwards for tax purposes	**(161,706)**	(40,412)
Deferral of taxable income in partnership	**1,492**	1,483
Future employee retirement costs	**(3,607)**	-
Working capital and other items	**(2,599)**	(2,787)
Valuation allowance	**-**	34,545
Future income tax liability (asset), net	**$ 86,640**	$ -

Canada Revenue Agency ("CRA") Assessment

In 2002, the CRA assessed, as a $30 million forgiveness of debt, a 1994 share issue in connection with the acquisition of North Atlantic in 1994 by a Vitol Refining S.A. affiliate. North Atlantic disagrees with the CRA's position and believes that the value of the common shares issued in 1994 was equal to the value of the debt exchanged and has filed a Notice of Objection to the CRA's Notice of Reassessment. There are no contingent amounts accrued related to this matter in these financial statements. Harvest is indemnified by the vendor of North Atlantic in respect of this contingent liability.

17. Employee Future Benefit Plans

Defined Contribution Pension Plan

Total expense for the defined contribution plan is equal to Harvest's required contributions and was $0.7 million, for the year ended December 31, 2007 (2006 – $0.1 million).

Defined Benefit Plans
The measurement of the accrued benefit obligation and annual expense for the defined benefit plans requires actuarial calculations and several assumptions. These assumptions, set annually on December 31, are as follows:

	December 31, 2007		December 31, 2006	
	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Discount rate	**5.0%**	**5.0 %**	**5.0%**	**5.0 %**
Expected long-term rate of return on plan assets	**7.0%**	**-**	**7.0%**	**-**
Rate of compensation increase	**3.5%**	**-**	**3.5%**	**-**
Employee contribution of pensionable income	**6.0%**	**-**	**6.0%**	**-**
Annual rate of increase in covered health care benefits	**-**	**11.0 %**	**-**	**12.0 %**
Expected average remaining service lifetime (years)	**11.7**	**10.8**	**11.7**	**11.1**

The assets of the defined benefit plan are invested and maintain the following asset mix:

	December 31, 2007	December 31, 2006
Bonds/fixed income securities	**32%**	**32%**
Equity securities	**68%**	**68%**

The expected long-term rates of return are estimated based on many factors, including the expected forecast for inflation, risk premiums for each class of asset, and current and future financial market conditions.

The defined benefit pension plans were subject to an actuarial valuation on December 31, 2005 and the next valuation report is due no later than December 31, 2008. The post-retirement health care benefits plan was last subject to an actuarial valuation on December 31, 2006.

	December 31, 2007		December 31, 2006	
	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Employee benefit obligation, beginning of year	**$ 43,101**	**$ 6,027**	**$ 38,754**	**$ 5,315**
Current service costs	**3,043**	**369**	**648**	**88**
Interest	**2,357**	**316**	**546**	**74**
Actuarial losses	**1,409**	**162**	**3,422**	**601**
Plan amendment	**-**	**-**	**-**	**-**
Benefits paid	**(828)**	**(221)**	**(269)**	**(51)**
Impact of foreign exchange on translation	**-**	**-**	**-**	**-**
Employee benefit obligation, end of year	**49,082**	**6,653**	**43,101**	**6,027**
Fair value of plan assets, beginning of year	**36,576**	**-**	**31,878**	**-**
Actual return on plan assets	**(1,682)**	**-**	**3,181**	**-**
Employer contributions	**3,428**	**221**	**1,306**	**51**
Employee contributions	**1,409**	**-**	**480**	**-**
Benefits paid	**(828)**	**(221)**	**(269)**	**(51)**
Impact of foreign exchange on translation	**-**	**-**	**-**	**-**
Fair value of plan assets, end of year	**38,903**	**-**	**36,576**	**-**
Funded status	**(10,179)**	**(6,653)**	**(6,525)**	**(6,027)**
Unamortized balances:				
Net actuarial losses	**4,664**	**-**	**325**	**-**
Past services	**-**	**-**	**-**	**-**
Carrying amount	**$ (5,515)**	**$ (6,653)**	**$ (6,200)**	**$ (6,027)**

	December, 31, 2007		December 31, 2006	
Summary:				
Pension plans	$	**5,515**	$	**6,200**
Other benefit plans		**6,653**		**6,027**
Carrying amount	$	**12,168**	$	**12,227**

Estimated pension and other benefit payments to plan participants, which reflect expected future service, expected to be paid from 2008 to 2017 are summarized in the commitment table [see Note 20].

The table below shows the components of the net benefit plan expense:

	Year ended December 31, 2007		Year ended December 31, 2006	
	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Current service cost	$ 3,043	$ 369	$ 648	$ 88
Interest costs	2,357	316	546	74
Expected return on assets	(2,657)	-	(563)	-
Amortization of net actuarial losses	-	101	-	588
Net benefit plan expense	$ 2,743	$ 786	$ 631	$ 750

A 1% change in the expected health care cost trend rate would have the following annual impacts as at December 31, 2007:

	1% Increase		1% Decrease	
Impact on post-retirement benefit expense	$	1	$	(2)
Impact on projected benefit obligation		9		(11)

18. Financial Instruments and risk management contracts

Financial instruments of Harvest consist of cash, accounts receivable, long-term receivables, accounts payable and accrued liabilities, cash distribution payable, bank loan, risk management contracts, convertible debentures and senior notes. The carrying value and fair value of these financial instruments at December 31, 2007 is disclosed below by financial instrument category, as well as any related gains or losses and interest income or expense for the year ended December 31, 2007:

Financial Instrument	Carrying Value	Fair Value	Gains/ (Losses)	Interest Income/ (Expense)	Other Income/ (Expense)
Loans and Receivables					
Accounts receivable	212,271	212,271	-	-	-
Lease payments receivable	3,532 (1)	3,532	-	201 (2)	-
Liabilites Held for Trading					
Net fair value of risk management contracts	149,673	149,673	(174,072) (3)	-	-
Other Liabilities					
Accounts payable	270,243	270,243	-	-	-
Cash distribution payable	44,487	44,487	-	-	-
Bank loan	1,279,501	1,279,501	-	(71,477) (4)	(4,509) (4)
$7^{7/8}$% Senior Notes	241,148 (6)	232,646	-	(22,561) (5)	-
Convertible debentures	651,768	623,255	-	(59,238) (5)	-

(1) Included in accounts receivable on the balance sheet.
(2) Included in petroleum, natural gas, and refined product sales in the statement of income and comprehensive income.
(3) Included in risk management contracts - realized and unrealized gains/(losses) in the statement of income and comprehensive income.
(4) Included in interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The amortization of financing fees related to this liability is included in Amortization of deferred finance charges in the statement of cash flows.
(5) Included in Interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The non-cash interest expense relating to the accretion of premiums, discounts or transaction costs that are netted against these liabilities are included in non-cash interest in the statement of cash flows.
(6) The face value of the $7^{7/8}$% Senior Notes at December 31, 2007 is $247.8 million (U.S. $250 million).

The fair value of the lease payments receivable is the present value of expected future cash flows. The fair values of the convertible debentures and the $7^{7/8}$% Senior Notes are based on quoted market prices as at December 31, 2007. The risk management contracts are recorded on the balance sheet at their fair value, accordingly, there is no difference between fair value and carrying value. The bank loan is recorded at amortized cost, but there are no transaction costs associated with this and the financing costs are included in intangible assets; therefore, there is no difference between the carrying value and the fair value. Due to the short term nature of cash, accounts receivable, accounts payable and cash distribution payable, their carrying values approximate their fair values.

(a) Risk Exposure

Harvest is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Harvest is also exposed, to a lesser extent, to credit risk on accounts receivable and counterparties to price risk management contracts and to liquidity risk relating to our debt.

(i.) Credit Risk

Upstream accounts receivable

Accounts receivable in our upstream operations are due from crude oil and natural gas purchasers as well as joint venture partners. These balances are due from companies in the petroleum and natural gas industry and are subject to normal industry credit risks. Concentration of credit risk is mitigated by having a broad customer base, which includes a significant number of companies engaged in joint operations with Harvest. Harvest periodically assesses the financial strength of its crude oil and natural gas purchasers and will adjust its marketing plan to mitigate credit risks. This assessment involves a review of external credit ratings; however, if external ratings are not available, we try to obtain a guarantee from the parent company. If this is not possible, we perform our own internal credit review based on the purchaser's past financial performance. The credit risk associated with our joint venture partners is mitigated by reviewing the credit history of partners and requiring some partners to provide cash upfront in the form of cash calls for significant capital projects. As well, most agreements have a net off provision that enables us to use the proceeds from the sale of production that would otherwise be taken in kind by the partner to net off amounts owing from the partner that are in default. Generally, the only instances of impairment are when a purchaser or partner goes bankrupt.

Risk Management Contract Counterparties

Harvest is also exposed to credit risk from the counterparties to our risk management contracts. This risk is managed by diversifying Harvest's risk management portfolio among a number of counterparties and by dealing with investment grade financial institutions. We have no history of impairment with these counterparties and therefore no impairment is recorded at December 31, 2007 or 2006.

Supply and Offtake Agreement Accounts Receivable (Vitol)

The Supply and Offtake Agreement entered into in conjunction with the purchase of the refinery exposed Harvest to the credit risk of Vitol Refining S.A. ("Vitol") as all feedstock purchases and substantially all product sales are made with Vitol. Harvest mitigates this risk by requiring that Vitol maintain a minimum B+ credit rating as assessed by Standard and Poors. If the credit rating falls below this line, additional security is required to be supplied to Harvest.

Other Accounts Receivable

Harvest does not have any significant exposure to any individual customer in its downstream operations and its policy is to manage its credit risk by dealing with only financially sound customers. Credit is extended based on an evaluation of the customer's financial condition. The carrying amount of accounts receivable reflects management's assessment of the associated credit risks.

Harvest is also exposed to credit risk from customers due to the lease payments receivable relating to our net investment in vehicle and equipment leases. As some of the counterparties to these leases are employees or distributors, any over due amounts can be deducted from wages or commissions and therefore, the credit risk is low.

(ii.) Liquidity Risk

Harvest is exposed to liquidity risk mainly due to our outstanding bank balances and $7^{7/8}$% Senior Notes with repayment requirements. This risk is mitigated by managing the maturity dates on our obligations and complying with the covenants.

(iii.) Market Risk

Harvest is exposed to three types of market risks: interest rate risk, foreign currency exchange rate risk and commodity price risk.

Interest rate risk

Harvest is exposed to interest rate risk on its bank loans as interest rates are determined in relation to floating market rates. Harvest's convertible debentures and $7^{7/8}$% Senior Notes have fixed interest rates and therefore do not create an interest rate risk. Harvest manages its exposure to interest rate risk by maintaining its debt in a combination of floating rate debt denominated in Canadian dollars and bearing interest relative to the Canadian interest rate benchmark.

In addition, Harvest manages its interest rate risk by targeting appropriate levels of debt relative to its expected cash flow from operations.

Foreign currency exchange rate risk

Harvest is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on its U.S. dollar denominated revenues and in respect of its refinery crude oil purchases and sales of refined products. In addition, Harvest's $7^{7/8}$% Senior Notes are denominated in U.S. dollars (U.S.$250 million). Interest is payable semi-annually in U.S. dollars on the notes; therefore, any interest payable at the balance sheet date is also subject to currency exchange rate risk. Harvest manages these exchange rate risks by occasionally entering into fixed rate currency exchange contracts on future U.S. dollar payments and U.S. dollar sales.

Commodity Price Risk

Harvest uses price risk management contracts for a portion of its crude oil, natural gas and refined product sales to manage its commodity price exposure and power costs. These contracts are recorded on the balance sheet at their fair value as of the balance sheet date, with changes from the prior period's fair value recorded in net income for the period. These fair values are generally determined as the difference between the stated fixed price of the contract and some expected future price of the underlying asset. Variances in expected future prices expose us to commodity price risk as they will change the gain or loss that we ultimately realize on these contracts. This risk is mitigated by continuously monitoring the effectiveness of these contracts and other risk management actions.

(b) Fair Values

At December 31, 2007, the net fair value deficiency reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $149.7 million ($1.9 million – December 31, 2006), which was included in the balance sheet as follows: Fair value of risk management contracts (current assets) $16.4 million, fair value deficiency of risk management contracts (current liabilities) $131.0 million and fair value deficiency of risk management contracts $35.1 million.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at December 31, 2007:

Quantity	Type of Contract	Term	Average Price	Fair value
Crude Oil Price Risk Management				
10,000 bbl/d	WTI Participating swap	Jan. 08 – Jun. 08	US$60.00(b)	(15,873)
6,000 bbl/d	WTI 3-way contract	Jul. 08 – Dec. 08	US$62.00 - $87.53 ($72.00)(c)	(9,015)
				$ (24,888)
Refined Product Price Risk Management				
10,000 bbl/d	NYMEX heating oil 3-way contract	Jan. 08 – Dec. 08	US$60.90 - $93.31 ($81.06)(e)(k)	$ (56,929)
6,000 bbl/d	Platt's fuel oil 3-way contract	Jan. 08 – Dec. 08	US$43.00 - $63.21 ($51.67)(f)	(25,196)
2,000 bbl/d	NYMEX heating oil collar	Jan. 08 – Dec. 08	US$79.80 - $91.35(g) (k)	(12,513)
2,000 bbl/d	Platt's fuel oil collar	Jan. 08 – Dec. 08	US$51.00 - $58.68(h)	(11,203)
12,000 bbl/d	NYMEX heating oil 3-way contract	Jan. 09 – Jun. 09	US$72.59 - $98.73 ($86.52)(i) (k)	(21,840)
8,000 bbl/d	Platt's fuel oil 3-way contract	Jan. 09 – Jun. 09	US$49.75 - $65.89 ($57.38)(j)	(13,255)
				$ (140,936)
Natural Gas Price Risk Management				
276 GJ/d	Fixed price – natural gas contract	Jan. 08 – Dec. 08	Cdn$4.16(d)	**$ (210)**
Electricity Price Risk Management				
35 MWH	Electricity price swap contracts	Jan. 08 – Dec. 08	Cdn $56.69	**$ 5,631**
Refined Product Crack Spread Risk Management				
2,000 bbl/d	Platt's fuel oil crack swap	Jan. 08 – Dec. 08	US($16.50)	$ 1,815
6,000 bbl/d	NYMEX heating oil crack swap	Jan. 08 – Dec. 08	US$14.63	30
6,000 bbl/d	NYMEX RBOB crack swap	Jul. 08 – Dec. 08	US$10.00	290
				$ 2,135
Foreign Currency Exchange Rate Risk Management				
$8,333,333/month	U.S./Cdn dollar exchange rate swap	Jan. 08 – Jun. 08	1.1099 Cdn/US	5,865
$10,000,000/month	U.S./Cdn dollar collar	Jan. 08 – Dec. 08	1.000 Cdn/US- 1.055 Cdn/US(a)	2,730
				$ 8,595
Total net fair value deficiency of risk management contracts				**$ (149,673)**

(a) If the market price is below $1.000, price received is $1.000; if the market price is between $1.000 and the ceiling of $1.055, the price received is market price; if the market price is over the ceiling of $1.055, price received is the stated ceiling price.

(b) This is the average price of the price floors. Harvest realizes this price plus 67-79%, or an average of 73%, of the difference between spot price and the given floor price.

(c) If the market price is below $62.00, price received is market price plus $10.00; if the market price is between $62.00 and $72.00, the price received is $72.00; if the market price is between $72.00 and the ceiling of $87.53, the price received is market price; if the market price is over the ceiling of $87.53, price received is $87.53.

(d) This contract contains an annual escalation factor such that the fixed price is adjusted each year.

(e) If the market price is below $60.90, price received is market price plus $20.16; if the market price is between $60.90 and $81.06, the price received is $81.06; if the market price is between $81.06 and the ceiling of $93.31, the price received is market price; if the market price is over the ceiling of $93.31, price received is $93.31.

(f) If the market price is below $43.00, price received is market price plus $8.67; if the market price is between $43.00 and $51.67, the price received is $51.67; if the market price is between $51.67 and the ceiling of $63.21, the price received is market price; if the market price is over the ceiling of $63.21, price received is $63.21.

(g) If the market price is below $79.80, price received is $79.80; if the market price is between $79.80 and $91.35, the price received is market price; if the market price is over the ceiling of $91.35, price received is $91.35.

(h) If the market price is below $51.00, price received is $51.00; if the market price is between $51.00 and the ceiling of $58.68, the price received is market price; if the market price is over the ceiling of $58.68, price received is $58.68.

(i) If the market price is below the floor price of $72.59, price received is market price plus $13.93; if the market price is between the floor price of $72.59 and $86.52, the price received is $86.52; if the market price is between $86.52 and the ceiling of $98.73, the price received is market price; if the market price is over the ceiling of $98.73, price received is $98.73.

(j) If the market price is below the floor of $49.75, price received is market price plus $7.63; if the market price is between the floor price of $49.75 and $57.38, the price received is $57.38; if the market price is between $57.38 and the ceiling of $65.89, the price received is market price; if the market price is over the ceiling of $65.89, price received is $65.89.

(k) Heating oil contracts are contracted in U.S. dollars per U.S. gallon and are presented in this table in U.S. dollars per barrel for comparative purposes (1 barrel equals 42 U.S. gallons).

For the year ended December 31, 2007, the total unrealized gain/loss on risk management contracts recognized in the consolidated statement of income and comprehensive income was a loss of $147.8 million (2006 - a gain of $52.2 million), which represents the change in fair value of financial assets and liabilities classified as held for trading. The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

19. Segment Information

Harvest operates in Canada and has two reportable operating segments, Upstream and Downstream. Harvest's upstream operations consist of development, production and subsequent sale of petroleum, natural gas and natural gas liquids, while its downstream operations include the purchase of crude oil, the refining of crude oil, the sale of the refined products including a network of retail operations and the supply of refined products to commercial and wholesale customers.

Results of Continuing Operations	Downstream[1]		Upstream[1]		Total	
	2007	2006	**2007**	2006	**2007**	2006
Revenue[2][3]	**$ 3,098,556**	$ 460,359	**$ 1,184,457**	$ 1,120,575	**$ 4,283,013**	$ 1,580,934
Royalties	**-**	-	**(213,413)**	(200,109)	**(213,413)**	(200,109)
Less:						
Purchased products for resale and processing	**2,667,714**	386,014	**-**	-	**2,667,714**	386,014
Operating[4]	**229,290**	34,063	**300,918**	242,474	**530,208**	276,537
Transportation and marketing	**34,970**	5,060	**11,946**	12,142	**46,916**	17,202
General and administrative	**1,713**	-	**34,615**	28,372	**36,328**	28,372
Transaction costs	**-**	-	**-**	12,072	**-**	12,072
Depletion, depreciation, amortization and accretion	**72,599**	15,482	**454,142**	413,988	**526,741**	429,470
	$ 92,270	$ 19,740	**$ 169,423**	$ 211,418	**261,693**	231,158
Realized net losses on risk management contracts					**(26,291)**	(44,808)
Unrealized net (losses) gains on risk management contracts					**(147,781)**	52,179
Interest and other financing charges on short term debt					**(5,584)**	(4,864)
Interest and other financing charges on long term debt					**(152,201)**	(78,828)
Foreign exchange gain (loss)					**109,316**	(21,100)
Large corporations tax and other tax					**974**	9
Future income tax					**(65,802)**	2,300
Net (loss) income					**$ (25,676)**	$ 136,046
Total Assets[5]	**$ 1,482,904**	$ 1,727,797	**$ 3,952,337**	$ 3,990,004	**$ 5,451,683**	$ 5,745,558
Capital Expenditures						
Development and other activity	**$ 44,111**	$ 21,411	**$ 300,674**	$ 376,881	**$ 344,785**	$ 398,292
Business acquisitions	**-**	1,597,793	**170,782**	2,422,180[6]	**170,782**	4,019,973
Property acquisitions	**-**	-	**27,943**	65,773	**27,943**	65,773
Property dispositions	**-**	-	**(60,569)**	(20,856)	**(60,569)**	(20,856)
Increase in other non-current assets	**-**	165	**-**	-	**-**	165
Total expenditures	**$ 44,111**	$ 1,619,369	**$ 438,830**	$ 2,843,978	**$ 482,941**	$ 4,463,347
Property, plant and equipment						
Cost	**$ 1,164,310**	$ 1,320,698	**$ 4,247,819**	$ 3,801,054	**$ 5,412,129**	$ 5,121,752
Less: Accumulated depletion, depreciation, amortization and accretion	**(72,277)**	(14,660)	**(1,142,345)**	(706,540)	**(1,214,622)**	(721,200)
Net book value	**$ 1,092,033**	$ 1,306,038	**$ 3,105,474**	$ 3,094,514	**$ 4,197,507**	$ 4,400,552
Goodwill						
Beginning of year	**$ 209,930**	$ -	**$ 656,248**	$ 43,832	**$ 866,178**	$ 43,832
Addition (reduction) to goodwill	**(33,946)**	209,930	**20,546**	612,416	**(13,400)**	822,346
End of year	**$ 175,984**	$ 209,930	**$ 676,794**	$ 656,248	**$ 852,778**	$ 866,178

(1) Accounting policies for segments are the same as those described in the Significant Accounting Policies

(2) Of the total downstream revenue for the year ended December 31, 2007, $2,651.5 million is from one customer (2006 - $427.1 million). No other single customer within either division represents greater than 10% of Harvest's total revenue.

(3) Of the total consolidated revenue for the year ended December 31, 2007, $1,626.3 million is attributable to sales in Canada (2006 - $1,150.5 million), while $2,656.7 million is attributable to sales in the United States (2006 - $430.4 million).

(4 Downstream operating expenses for the period ended December 31, 2007 include $34.5 million of turnaround and catalyst costs related to the planned shutdown of the Isomax and Platformer commencing on September 21, 2007.

(5) Total Assets on a consolidated basis includes $16.4 million (2006 - $27.8 million) relating to the fair value of risk management contracts

(6) Included in this amount is $1,975.3 million relating to the acquisition of Viking, which was acquired through the issuance of trust units and is therefore not reflected in the cash flow statement.

(7) There is no intersegment activity.

20. Commitments, Contingencies and Guarantees

From time to time, Harvest is involved in litigation or has claims brought against it in the normal course of business operations. Management of Harvest is not currently aware of any claims or actions that would materially affect Harvest's reported financial position or results from operations. In the normal course of operations, management may also enter into certain types of contracts that require Harvest to indemnify parties against possible third party claims, particularly when these contracts relate to purchase and sale agreements. The terms of such contracts vary and generally a maximum is not explicitly stated; as such the overall maximum amount of the obligations cannot be reasonably estimated. Management does not believe payments, if any, related to such contracts would have a material effect on Harvest's reported financial position or results from operations.

The following are the significant commitments and contingencies at December 31, 2007:

(a) North Atlantic has a Supply and Offtake Agreement with Vitol Refining S.A. This 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 for a minimum period of up to two years 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 substantially all refined products produced by the refinery. As such, at December 31, 2007, North Atlantic had commitments totaling approximately $843.6 million (2006 - $550.2 million) in respect of future crude oil feedstock purchases and related transportation from Vitol Refining S.A.

(b) North Atlantic has an agreement with Newsul Enterprises Inc. ("Newsul") whereby North Atlantic committed to provide Newsul with its inventory and production of sulphur to February 12, 2008. The agreement has been renewed for a further period of ten years.

Newsul has named North Atlantic in a claim in the amount of US$2.7 million and has requested the services of an arbitration board to make a determination on the claim. The claim is for additional costs and lost revenues related to alleged contaminated sulphur delivered by North Atlantic. An accrual of $0.5 million has been established based on North Atlantic's estimate of their liability, but since the eventual outcome of the arbitration hearing is undeterminable, there exists an exposure to loss in excess of the amount accrued.

(c) North Atlantic has an environmental agreement with the Province of Newfoundland and Labrador, Canada, committing to programs that reduce the environmental impact of the refinery over time. Initiatives include a schedule of activities to be undertaken with regard to improvements in areas such as emissions, waste water treatment, terrestrial effects, and other matters. In accordance with the agreement, certain projects have been completed and others have been scheduled. Costs relating to certain activities scheduled to be undertaken over the next two years are estimated to be approximately $3.5 million and are included in the table below; costs can not yet be estimated for the remaining projects.

(d) North Atlantic has been named a defendant in The State of New Hampshire versus Amerada Hess Corp. et al, one of more than 100 methyl tertiary butyl ether ("MTBE") U.S. 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 lawsuits 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 consolidated financial statements in respect of this matter. Harvest is indemnified by Vitol Group B.V. in respect of this contingent liability.

(e) Petro-Canada, a former owner of the North Atlantic refinery, holds certain contractual rights in relation to production at the refinery, namely:

  i. a right to share, subject to a maximum limit, in the profits of the sale of any refined product, refined at the refinery, sold in Canada, exclusive of the province of Newfoundland and Labrador;

  ii. a right of first refusal to any refinery and/or terminaling capacity in excess of North Atlantic's requirements;

  iii. a right to participate in any venture to produce petrochemicals at the refinery; and

iv. the rights in paragraphs (i) and (ii) above continue for a period of 25 years from December 1, 1986, while the rights in paragraph (iii) continue until amended by the parties.

The following is a summary of Harvest's contractual obligations and commitments as at December 31, 2007:

	Payments Due by Period						
	2008	**2009**	**2010**	**2011**	**2012**	**Thereafter**	**Total**
Debt repayments [1]	-	-	1,279,501	247,825	-	-	**1,527,326**
Capital commitments[2]	15,924	1,300	-	-	-	-	**17,224**
Operating leases[3]	7,572	6,655	5,742	5,292	1,853	248	**27,362**
Pension contributions[4]	1,143	1,583	2,048	2,454	2,847	21,285	**31,360**
Transportation agreements[5]	2,249	1,684	1,269	565	296	47	**6,110**
Feedstock commitments[6]	843,583	-	-	-	-	-	**843,583**
Contractual obligations	**870,471**	**11,222**	**1,288,560**	**256,136**	**4,996**	**21,580**	**2,452,965**

(1) Assumes that the outstanding convertible debentures either convert at the holders' option for Units or are redeemed for Units at Harvest's option.
(2) Relating to drilling contracts, AFE commitments, equipment rental contracts and environmental capital projects [see Note 20(c) above].
(3) Relating to building and automobile leases.
(4) Relating to expected contributions for employee benefit plans [see Note 17].
(5) Relating to oil and natural gas pipeline transportation agreements.
(6) Relating to crude oil feedstock purchases and related transportation costs [see Note 20(a) above].

21. Reconciliation of the Consolidated Financial Statements to United States Generally Accepted Accounting Principles

These consolidated financial statements have been prepared in accordance with Canadian GAAP which, in most respects, conforms to U.S. GAAP. Any differences in accounting principles as they have been applied to the accompanying consolidated financial statements are not material except as described below. Items required for financial disclosure under U.S. GAAP may be different from disclosure standards under Canadian GAAP; any such differences are not reflected here.

The application of U.S. GAAP would have the following effects on net income as reported:

		Year Ended December 31, 2007		2006
Net income (loss) under Canadian GAAP	**$**	**(25,676)**	$	136,046
Adjustments				
Write-down of property, plant and equipment (a)		**-**		(615,000)
Unrealized loss on risk management contracts (f)		**-**		(398)
Depletion, depreciation, amortization and accretion (b)		**78,180**		8,825
Non-cash interest expense on debentures (d)		**6,371**		454
Non-cash interest expense on Senior Notes (h)		**842**		-
Amortization of deferred financing charges (d)		**(3,471)**		65
Foreign exchange gain on Senior Notes (h)		**1,720**		-
Foreign exchange gain (loss) on unit distribution (i)		**10,045**		(1,038)
Non-controlling interest (e)		**-**		(65)
Non-cash general and administrative expenses (c)		**(443)**		(3,291)
Future income tax recovery (g)		**91,626**		670
Net income (loss) under U.S. GAAP before cumulative effect of change in accounting policy		**159,194**		(473,732)
Cumulative effect of change in accounting policy (c)		**-**		4,891
Net income (loss) under U.S. GAAP after cumulative effect of change in accounting policy		**159,194**		(468,841)
Net change in cumulative translation adjustment (i)		**(253,677)**		47,911
Employee future benefits – actuarial loss		**(4,339)**		-
Comprehensive income (loss)	$	**(98,822)**	$	(420,930)
Basic				
Net income (loss) per Trust Unit under U.S. GAAP before cumulative effect of change in accounting policy	$	**1.15**	$	(4.66)
Cumulative effect of change in accounting policy		**-**		0.05
Net income (loss) per Trust Unit under U.S. GAAP after cumulative effect of change in accounting policy	$	**1.15**	$	(4.61)
Diluted				
Net income (loss) per Trust Unit under U.S. GAAP before cumulative effect of change in accounting policy	$	**1.14**	$	(4.66)
Cumulative effect of change in accounting policy		**-**		0.05
Net income (loss) per Trust Unit under U.S. GAAP after cumulative effect of change in accounting policy	$	**1.14**	$	(4.61)
Statement of Accumulated Income (loss)				
Balance, beginning of year – U.S. GAAP		**33,880**		(895,736)
Net income (loss) – U.S. GAAP		**159,194**		(473,732)
Cumulative effect of change in accounting policy		**-**		4,891
Change in redemption value of Trust Units		**371,316**		1,398,457
Balance, end of year – U.S. GAAP		**564,390**		33,880
Accumulated other comprehensive income (loss)				
Balance, beginning of year – U.S. GAAP		**47,586**		-
Other comprehensive income		**(258,016)**		47,911
Employee future benefits – Adoption of FAS 158 (j)		**-**		(325)
Balance, end of year – U.S. GAAP		**(210,430)**		47,586

The application of U.S. GAAP would have the following effect on the consolidated balance sheets as reported:

	December 31, 2007		December 31, 2006	
	Canadian GAAP	**U.S. GAAP**	Canadian GAAP	U.S. GAAP
Assets				
Property, plant and equipment (a) (b)	**$ 4,197,506**	**$ 3,670,688**	$ 4,393,832	$ 3,788,606
Deferred charges (d) (f) (h)	**$ -**	**$ 23,390**	$ 35,657	$ 34,199
Non current benefit plan assets (j)	**$ -**	**$ 393**	$ -	$ 373
Future income tax (f)(g)	**$ -**	**$ 4,986**	$ -	$ -
Liabilities				
Accounts payable and accrued liabilities (c)	**$ 270,240**	**$ 268,669**	$ 294,582	$ 292,338
Current portion of convertible debentures (d)	**$ 24,273**	**$ 24,210**	$ -	$ -
Current other benefit plan liability (j)	**$ -**	**$ 170**	$ -	$ 162
Deferred credit (f)	**$ -**	**$ -**	$ 794	$ 794
7 7/8%Senior notes (h)	**$ 241,148**	**$ 246,710**	$ 291,350	$ 289,952
Convertible debentures – liability (d)	**$ 627,495**	**$ 671,818**	$ 601,511	$ 627,722
Non current benefit plan liability (j)	**$ 12,168**	**$ 17,054**	$ 12,227	$ 12,762
Future income tax (f)(g)	**$ 86,640**	**$ -**	$ -	$ -
Temporary equity (e)	**$ -**	**$ 2,997,136**	$ -	$ 2,680,017
Unitholders' Equity				
Unitholders' capital (e)	**$ 3,736,080**	**$ -**	$ 3,046,876	$ -
Equity component of convertible debentures (d)	**$ 39,537**	**$ -**	$ 36,070	$ -
Additional paid-in capital	**$ -**	**$ 9,913**	$ -	$ 9,913
Accumulated income (i)	**$ 246,865**	**$ 564,390**	$ 271,155	$ 33,880
Cumulative foreign currency translation adjustment (i)	**$ -**	**$ -**	$ 46,873	$ -
Accumulated other comprehensive income (j)(i)	**$ (196,759)**	**$ (210,430)**	$ -	$ 47,586

(a) Under Canadian GAAP, Harvest performs an impairment test that limits the capitalized costs of its petroleum and natural gas assets to the discounted estimated future net revenue from proved and probable petroleum and natural gas reserves plus the cost of unproved properties less impairment, estimated future prices and costs. The discount rate used is equal to Harvest's risk free interest rate. Under U.S. GAAP, entities using the full cost method of accounting for petroleum and natural gas activities perform an impairment test on each cost centre using discounted future net revenue from proved petroleum and natural gas reserves discounted at 10%. The prices used under the U.S. GAAP impairment test are those in effect at year end. There was no impairment under U.S. GAAP at December 31, 2007. As at December 31, 2006, the application of the ceiling test under U.S. GAAP resulted in a write down of $615.0 million of capitalized costs.

(b) Under Canadian GAAP, proved reserves are estimated using estimated future prices and costs. These proved reserves form the basis for the depletion calculation.

Under U.S. GAAP, proved reserves used for the depletion calculation are estimated using constant prices and costs as of the date the estimate of reserves is made. In both the current and comparative year there were differences in proved reserves under U.S. GAAP and Canadian GAAP and as a result the difference is realized in the depletion expense. Additionally, the ceiling test write down required under U.S. GAAP in 2006 reduced the U.S. GAAP depletable asset base which results in a lower depletion expense in 2007 and future years.

(c) Under Canadian GAAP, the Trust determines compensation expense and the resulting obligation related to its Trust Unit Incentive Plan and Unit Award Plan using the intrinsic value method described in Note 2 (j). Under U.S. GAAP, for the year ended December 31, 2006 Harvest adopted SFAS 123(R) "*Share Based Payments*" using the modified prospective approach. Under FAS 123(R), expenses and obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting and are revalued at each period end. As a result, general and administrative expense is higher under U.S. GAAP by $0.4 million for the year ended December 31, 2007 (2006 - $3.3 million) and accounts payable and accrued liabilities is higher under U.S. GAAP by $0.7 million as at December 31, 2007 (December 31, 2006 – lower by $2.2 million).

To the extent compensation costs relates to employees directly involved in natural gas and crude oil exploration and development activities, such amounts are capitalized to property, plant and equipment. Amounts not capitalized are recognized as administrative expenses.

The Trust adopted SFAS 123(R) under the modified prospective approach, which requires the cumulative impact of a change in an accounting policy to be presented in the current year consolidated statement of income. The cumulative effect of initially adopting SFAS 123(R) on January 1, 2006 was a gain of $4.9 million.

(d) Under Canadian GAAP, Harvest's convertible debentures are classified as debt with a portion, representing the value associated with the conversion feature, being allocated to equity under Canadian GAAP. Issue costs related to the debentures are netted against each respective debt and equity component. In addition, under Canadian GAAP a non-cash interest expense representing the effective yield of the debt component and the amortization of the issue costs is recorded in the consolidated statements of income with a corresponding credit to the convertible debenture liability balance to accrete that balance to the full principal due on maturity.

Under U.S. GAAP, the convertible debentures are classified as debt in their entirety, and issue costs are recorded as deferred charges. To the extent that a portion of the issue costs are netted against the respective debt and equity components of the convertible debentures under Canadian GAAP there is a difference in the capitalization and amortization of the related deferred charges under U.S. GAAP. The non-cash interest expense recorded under Canadian GAAP would not be recorded under U.S. GAAP.

In addition, convertible debentures that are assumed in a business combination are recorded at their fair value at the date of the acquisition as part of the cost of the acquired enterprise. Under U.S. GAAP, if the conversion feature is in-the-money at the acquisition date (a beneficial conversion feature), the feature should be recognized and measured by allocating a portion of the proceeds equal to the intrinsic value of that feature to additional paid-in capital. Where the debenture has a stated redemption date, the corresponding value is recognized as a discount on the convertible debenture balance and accreted from the date of acquisition to the redemption date.

(e) Under Harvest's Trust Indenture, Trust Units are redeemable at any time on demand by the Unitholder for cash. Under U.S. GAAP, the amount included on the consolidated balance sheet for Unitholders' Equity would be reduced by an amount equal to the redemption value of the Trust Units as at the balance sheet date. The redemption value of the Trust Units is determined with respect to the trading value of the Trust Units as at each balance sheet date, and the amount of the redemption value is classified as temporary equity. Changes, if any, in the redemption value during a period results in a charge to permanent equity.

(f) Under U.S. GAAP, SFAS 133 "*Accounting for Derivative Instruments and Hedging Activities*" requires that all derivative instruments be recorded on the consolidated balance sheet as either an asset or liability measured at fair value, and requires that changes in fair value be recognized currently in income unless specific hedge accounting criteria are met. U.S. GAAP requires that a company formally document, designate, and assess the effectiveness of derivative instruments before hedge accounting may be applied. Harvest had not formally documented and designated any hedging relationships as at December 31, 2007 or December 31, 2006 and as such, its risk management contracts were not eligible for hedge accounting treatment under U.S. GAAP.

Harvest implemented fair value accounting effective January 1, 2004 under Canadian GAAP and had designated a portion of its risk management contracts as hedges. During the year ended December 31, 2004, the Trust discontinued hedge accounting for all risk management contracts under Canadian GAAP. Upon discontinuing hedge accounting, a deferred charge or gain is recorded representing the fair value of the contract at that time. This difference is amortized over the term of the contract. Under U.S. GAAP there were no contracts designated as hedges. To the extent deferred charges and credits were recorded and amortized when hedge accounting was discontinued, there is a difference between Canadian and U.S. GAAP. The deferred charges and gains were to be amortized under Canadian GAAP for the year ended December 31, 2006, and created a difference from U.S. GAAP. There was no such impact for the year ended December 31, 2007.

(g) The Canadian GAAP liability method of accounting for income taxes is similar to the U.S. GAAP SFAS 109, "*Accounting for Income Taxes*", which requires the recognition of tax assets and liabilities for the expected future tax consequences of events that have been recognized in Harvest's consolidated financial statements. Pursuant to U.S. GAAP, enacted tax rates are used to calculate future income tax, whereas Canadian GAAP uses substantively enacted rates. There are no differences for the years ended December 31, 2007 and December 31, 2006 relating to tax rate differences.

Under Canadian GAAP as at December 31, 2007, Harvest's carrying value of its net assets exceed its tax basis and accordingly results in recording a future income tax liability. Adjustments under U.S. GAAP result in a large future income tax recovery and corresponding future income tax asset balance being booked, as the ceiling test write down from 2006 significantly lowered Harvest's property, plant, and equipment carrying value under U.S. GAAP and thus increased the corresponding temporary differences for future tax purposes.

(h) With the adoption of Financial Instruments under Canadian GAAP effective January 1, 2007, issue costs are applied against the $7^{7/8}$% Senior Notes balance and accreted into income using the effective interest method. Under U.S. GAAP, these amounts are capitalized as a deferred charge and expensed into income using the effective interest method.

(i) With the adoption of the new accounting standards for financial instruments under Canadian GAAP effective January 1, 2007, the cumulative translation adjustment generated upon translating the financial statements of Harvest's downstream operations denominated in a foreign currency previously recognized as a separate component of equity is now recognized in comprehensive income consistent with the treatment under U.S. GAAP. Additionally, under U.S. GAAP, partnership distributions are required to be translated at the historic foreign exchange rate in place at the time of initial paid-in capital and any translation gains or losses are recorded in other comprehensive income. Under Canadian GAAP, it is permissible to translate foreign currency denominated partnership distributions at the historic exchange rate that has been proportionately adjusted for the subsequent periods when income has been earned. The effects of the translation is reflected in net income.

(j) At December 31, 2006 the Trust adopted U.S. GAAP SFAS 158, "*Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R).* Under SFAS 158, the over-funded or under-funded status of our defined benefit postretirement plan are recognized on the balance sheet as an asset or liability and changes in the funded status are recognized through comprehensive income. As a result, for the year ended December 31, 2007 employee future benefits are higher by $4.3 million (2006 – $0.3 million) and $4.3 million was included in other comprehensive income (2006 – $0.3 million included in accumulated other comprehensive income on adoption of SFAS 158). Canadian GAAP currently does not require the Trust to recognize the funding status of the plan on its balance sheet.

k) In its December 31, 2007 financial statements, Harvest adopted the FASB Interpretation No. 48 *"Accounting for Uncertainty for Income Taxes"* (FIN 48). FIN 48 is an interpretation of FASB Statement 109 *"Accounting for Income Taxes"* and outlines the recognition and related disclosure requirements of uncertain tax positions determined to be more likely than not, defined as greater than 50%, to be sustained on audit. This adoption did not result in a U.S. GAAP difference.

The following are standards and interpretations that have been issued by the Financial Accounting Standards Board ("FASB") which are not yet in effect for the periods presented but would become U.S. GAAP when implemented:

In September 2006, FASB issued Statement 157, "*Fair Value Measurements*". SFAS 157 defines fair value, establishes a framework for measuring fair value under U.S. GAAP and expands disclosures about fair value measurements. This statement is effective for fiscal years beginning after November 15, 2007. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In February 2007, the FASB issued SFAS No. 159, "*The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115*." This pronouncement permits entities to use the fair value method to measure certain financial assets and liabilities by electing an irrevocable option to use the fair value method at specified election dates. After election of the option, subsequent changes in fair value would result in the recognition of unrealized gains or losses as period costs during the period the change occurred. SFAS No. 159 becomes effective as of the beginning of the first fiscal year that begins after November 15, 2007, with early adoption permitted. However, entities may not retroactively apply the provisions of SFAS No. 159 to fiscal years preceding the date of adoption. We are currently evaluating the impact that SFAS No. 159 may have on our financial position, results of operations and cash flows.

Additional disclosures required under U.S. GAAP:
(thousands of Canadian dollars)

		December 31, 2007		December 31, 2006
Components of accounts receivable				
Trade	$	**115,112**	$	135,578
Accruals		**100,691**		118,573
	$	**215,803**	$	254,151
Components of prepaid expenses and deposits				
Prepaid expenses	$	**14,004**	$	11,877
Funds on deposit		**1,140**		836
	$	**15,144**	$	12,713

22. Subsequent Events

Subsequent to December 31, 2007, Harvest declared a distribution of $0.30 per unit for Unitholders of record on January 24, 2008, February 22, 2008, March 25, 2008 and April 22, 2008.

Between January 1, 2008 and March 12, 2008, an additional $577.0 million was committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. [see table in Note 20].

On January 31, 2008 the 10.5% debentures matured and the obligation was settled through the issuance of 1,116,593 Trust Units. See Note 12 for further details.

23. Related Party Transactions

During the year ended December 31, 2007, in the normal course of operations, Vitol Refining S.A. purchased $354.8 million of Iraqi crude oil through the Supply and Offtake Agreement at fair market value for processing, which has been sourced from a private corporation of which a director of Harvest is also a director and holds a minority ownership interest. As at December 31, 2007, no amount related to these transactions is included in accounts payable and accrued liabilities and $68.0 million is included in feedstock commitments for the purchase of Iraqi crude oil [See Note 20]. None of the U.S. $577.0 million committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. between January 1, 2008 and March 12, 2008 [see Note 22] was purchased from this private corporation. During the year ended December 31, 2006, there were no related party transactions.

24. Comparatives
Certain comparative figures have been reclassified to conform to the current year’s presentation.

DISCLOSURE CONTROLS AND PROCEDURES

A. Certifications

See Exhibits 99.1 and 99.2 to this annual report on Form 40-F.

B. Evaluation of Disclosure Controls and Procedures

As of December 31, 2007, an evaluation was carried out under the supervision of and with the participation of Registrant's management, including the President and Chief Executive Officer as well as the Chief Financial Officer, of the effectiveness of the Registrant's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act). Based on that evaluation, the President and Chief Financial Officer concluded that as of the end of the fiscal year, the design and operation of these disclosure controls and procedures were effective to ensure that information required to be disclosed by the Registrant in reports it files or submits under the Exchange Act were (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission's ("SEC") rules and forms and (ii) accumulated and communicated to the Registrant's management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

It should be noted that while the Registrant's principal executive officer and principal financial officer believe that the Registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Registrant's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

C. Management's Annual Report on Internal Control Over Financial Reporting

The required disclosure is included in the "Management's Report" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2007, filed as part of this annual report on Form 40-F.

D. Attestation Report of the Registered Public Accounting Firm

The required disclosure is included in the "Auditor's Report" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2007, and is filed as part of this annual report on Form 40-F.

E. Changes in Internal Control over Financial Reporting

During the period covered by this annual report on Form 40-F no changes occurred in the Registrant's internal control over financial reporting that have materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting, except for the appointment of a Chief Operating Officer, Downstream. The appointment enhanced our oversight of these operations.

.

NOTICES PURSUANT TO REGULATION BTR

None.

AUDIT COMMITTEE

Identification of Audit Committee

The Registrant has a separately designed standing Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The following individuals comprise the entire membership of the Registrant's Audit Committee: Dale Blue, Verne G. Johnson, and Hector J. McFadyen. All members of the Audit Committee are independent from management, and were responsible for approving Harvest's 2007 year end financial statements for recommendation to the Board of Directors.

Audit Committee Financial Expert

The Board of Directors of the registrant has determined that Mr. Blue has met the "audit committee financial expert" criteria (as that term is defined in paragraph 8(b) of General Instruction B to Form 40-F) and is considered an "independent" expert in accordance with the rules of the New York Stock Exchange.

The SEC has indicated that the designation of a person as an "audit committee financial expert" does not (i) mean that such person is an "expert" for any purpose, including without limitation for purposes of Section 11 of the Securities Act of 1933, (ii) impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the audit committee and the board of directors in the absence of such designation, or (iii) affect the duties, obligations or liability of any other member of the audit committee or the board of directors.

CODE OF ETHICS FOR CHIEF EXECUTIVE OFFICER AND SENIOR FINANCIAL OFFICERS

The Registrant has adopted a Code of Ethics (as that term is defined in Form 40-F) that applies to its principal executive, financial and accounting officers, and other members of senior management. Specifically, this code applies to the Registrant's President and Chief Executive Officer, the Chief Financial Officer, the Chief Operating Officer, Upstream, the Chief Operating Officer, Downstream, and the Vice President Corporate. It is available in print without charge to any person who requests it. Such requests may be made by contacting the Registrant's Investor Relations and Communications Advisor via email at: information@harvestenergy.ca or by phone at (403) 265-1178. All amendments to the code will be provided to any person who requests them. There were no waivers or amendments to the Code of Ethics in 2007.

PRINCIPAL ACCOUNTING FEES AND SERVICES – INDEPENDENT AUDITORS

Fees payable to the Registrant's independent auditor, KPMG LLP, for the years ended December 31, 2007 and December 31, 2006 totaled $1,411,650 and $1,177,092, respectively, as detailed in the following table. All funds are in Canadian dollars.

	Year ended December 31, 2007	Year ended December 31, 2006
Audit Fees	$ 1,042,650	$ 1,080,950
Audit-Related Fees	$ 369,000	$ 66,342
Tax Fees	$ -	$ 29,800
All Other Fees	$ -	$ -
TOTAL	$ 1,411,650	$ 1,177,092

The nature of the services provided by KPMG LLP under each of the categories indicated in the table is described below.

Audit Fees

Audit fees were for professional services rendered by KPMG LLP for the audit of the Registrant's annual financial statements and review of the Registrant's quarterly financial statements, as well as services provided in connection with statutory and regulatory filings or engagements including those related to prospectus offerings and their audit of internal controls over financial reporting.

Audit-Related Fees

Audit-related fees were for assurance and related services reasonably related to the performance of the audit or review of the annual statements and are not reported under "Audit Fees" above. These services consisted of French translation fees which have increased over the prior year in connection with prospectus offerings completed by Harvest late in 2006 and during the first half of 2007.

Tax Fees

Tax fees were for tax compliance, tax advice and tax planning professional services. These services consisted of: tax compliance, including the review of tax returns; and tax planning and advisory services relating to common forms of domestic and international taxation (i.e. income tax, capital tax, goods and services tax, and value added tax).

All Other Fees

In 2007 and 2006, no fees for services were incurred other than those described above under "Audit Fees," "Audit-Related Fees" and "Tax Fees".

PREAPPROVAL POLICIES AND PROCEDURES

It is within the mandate of the Registrant's Audit Committee to approve all audit and non-audit related fees. The Audit Committee will be informed as to the term of engagement and the compensation paid to the external auditor of the Registrant as well as review and pre-approve the non-audit services actually provided by the auditor pursuant to this pre-approval process at its first scheduled meeting following such pre-approval. The auditors also present the estimate for the annual audit-related services to the Audit Committee for approval prior to undertaking the annual audit of the financial statements.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has no material off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on the Registrant's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

CONTRACTUAL OBLIGATIONS

Annual Contractual Obligations *(000s)*	**Total**	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt(2)	**1,527,326**	-	1,279,501	247,825	-
Interest on long-term debt(4)	**233,881**	88,216	130,319	15,346	-
Interest on Convertible Debentures(3)	**252,454**	46,832	92,916	86,063	26,643
Operating and premise leases	**27,362**	7,572	12,397	7,145	248
Purchase commitments(5)	**17,224**	15,924	1,300	-	-
Asset retirement obligations(6)	**1,002,893**	24,617	17,350	27,437	933,489
Transportation (7)	**6,110**	2,249	2,953	861	47
Pension contributions	**31,360**	1,143	3,631	5,301	21,285
Feedstock commitments	**843,583**	843,583	-	-	-
Total	**3,942,193**	1,030,136	1,540,367	389,978	981,712

(1) As at December 31, 2007, we had entered into physical and financial contracts for production with average deliveries of approximately 8,000 bbl/d for 2008. We have also entered into financial contracts for our downstream production of refined products with average deliveries of approximately 34,000 bbl/d in 2008 and 10,000 bbl/d in 2009. We have also entered into financial contracts to minimize our exposure to fluctuating electricity prices. Please see Note 18 to the consolidated financial statements for further details.
(2) Assumes that the outstanding Convertible Debentures either convert at the holders' option or are redeemed for Units at our option.
(3) Assumes no conversions and redemption by Harvest for Trust Units at the end of the second redemption period. Only cash commitments are presented.
(4) Assumes constant foreign exchange rate.
(5) Relates to drilling commitments, AFE commitments and downstream purchase commitments.
(6) Represents the undiscounted obligation by period
(7) Relates to firm transportation commitment on the Nova pipeline.

For a discussion of the Registrant's other commitments, please read Note 20 to the Registrant's audited annual consolidated financial statements for the year ended December 31, 2007 attached as part of this annual report on Form 40-F.

In addition to those items noted above, as at December 31, 2007, we had entered into physical and financial contracts for deliveries of upstream production and downstream refined product throughout 2008 and into 2009 and have also entered into financial contracts to minimize our exposure to fluctuating electricity prices. Please see Note 18 to the consolidated financial statements for further details.

UNDERTAKING

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the SEC staff, and to furnish promptly, when requested to do so by the SEC staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

The Registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of the agent for service of process of the registrant shall be communicated promptly to the SEC by an amendment to the Form F-X referencing the file number.

SIGNATURE

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report on Form 40-F to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

Dated: March 27, 2008

HARVEST ENERGY TRUST

By: /s/ Robert W. Fotheringham
Name: Robert W. Fotheringham
Title: Chief Financial Officer of Harvest Operations Corp. on behalf of Harvest Energy Trust

EXHIBIT INDEX

The following exhibits are filed as part of this report.

Exhibit Number	Description
99.1	CEO Certification pursuant to Rule 13a-14(a) or 15d-14 of the Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
99.2	CFO Certification pursuant to Rule 13a-14(a) or 15d-14 of the Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
99.3	CEO Certification pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.4	CFO Certification pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.5	Consent of KPMG LLP.
99.6	Consent of McDaniel & Associates Consultants Ltd.
99.7	Consent of Gilbert Laustsen Jung Associates Ltd.

<u>Exhibit 99.1</u>

CERTIFICATION
REQUIRED BY RULE 13a-14(a) OR RULE 15d-14(a) OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John Zahary, certify that:

1. I have reviewed this annual report on Form 40-F of Harvest Energy Trust;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 27, 2008

/s/ John Zahary
Name: John Zahary
Title: President & Chief Executive Officer

EXHIBIT 99.2

CERTIFICATION
REQUIRED BY RULE 13a-14(a) OR RULE 15d-14(a) OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert W. Fotheringham, certify that:

1. I have reviewed this annual report on Form 40-F of Harvest Energy Trust;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 27, 2008

/s/ Robert W. Fotheringham____
Name: Robert W. Fotheringham
Title: Chief Financial Officer

EXHIBIT 99.3

CERTIFICATION
REQUIRED BY RULE 13a-14(b) OR RULE 15d-14(b) AND
SECTION 1350 OF CHAPTER 63 OF TITLE 18
OF THE UNITED STATES CODE

Harvest Energy Trust (the "Company") is filing its annual report on Form 40-F for the fiscal year ended December 31, 2007 (the "Report") on the date hereof with the United States Securities and Exchange Commission.

I, John Zahary, President & Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as enacted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 27, 2008

/s/ John Zahary
John Zahary
President & Chief Executive Officer

EXHIBIT 99.4

CERTIFICATION
REQUIRED BY RULE 13a-14(b) OR RULE 15d-14(b) AND
SECTION 1350 OF CHAPTER 63 OF TITLE 18 OF THE UNITED STATES CODE

Harvest Energy Trust (the "Company") is filing its annual report on Form 40-F for the fiscal year ended December 31, 2007 (the "Report") on the date hereof with the United States Securities and Exchange Commission.

I, Robert W. Fotheringham, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as enacted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 27, 2008

/s/ Robert W. Fotheringham
Robert W. Fotheringham
Chief Financial Officer

<u>EXHIBIT 99.5</u>

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of Harvest Operations Corp. on behalf of Harvest Energy Trust

We consent to the inclusion in this annual report on Form 40-F of:

- our audit report dated March 12, 2008 on the consolidated balance sheets of Harvest Energy Trust as at December 31, 2007 and 2006 and the consolidated statements of income and comprehensive (loss) income, unitholders' equity and cash flows for each of the years then ended,
- our Comments by Auditors for United States readers on Canada-United States Reporting Differences, dated March 12, 2008,
- our Report of Independent Registered Public Accounting Firm dated March 12, 2008 on the effectiveness of internal control over financial reporting as of December 31, 2007,

each of which is contained in this annual report on Form 40-F of the Trust for the fiscal year ended December 31, 2007.

signed "KPMG LLP"

Chartered Accountants

Calgary, Canada
March 27, 2008

EXHIBIT 99.6

CONSENT OF INDEPENDENT ENGINEERS

We hereby consent to the use in this Annual Report on Form 40-F of Harvest Energy Trust for the year ended December 31, 2007 of our report, dated March 11, 2008, evaluating the crude oil, natural gas, and natural gas liquids reserves attributable to properties owned by Harvest Energy Trust.

McDaniel & Associates Consultants Ltd.

Calgary, Alberta

Date: March 26, 2008

Sincerely,

/s/ Bryan J. Wurster

Bryan J. Wurster, P.Eng.
Vice President

EXHIBIT 99.7

CONSENT OF INDEPENDENT ENGINEERS

We hereby consent to the use in this Annual Report on Form 40-F of Harvest Energy Trust for the year ended December 31, 2007, our report, dated March 10, 2008, evaluating the crude oil, natural gas, and natural gas liquids reserves attributable to certain properties owned by Harvest Energy Trust.

GLJ Petroleum Consultants Ltd.

Calgary, Alberta

Date: March 26, 2008

Yours truly,

/s/ Harry Jung______________
Harry Jung, P. Eng.
President