UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 20-F

(Mark One)

[ ] REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR (g) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

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

For the fiscal year ended: **DECEMBER 31, 2013**

OR

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

OR

[ ] SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from **n/a** to **n/a**

Commission file number **333-121620**

HARVEST OPERATIONS CORP.

(Exact name of Registrant as specified in its charter)

HARVEST OPERATIONS CORP.
(Translation of Registrant's name into English)

ALBERTA, CANADA
(Jurisdiction of incorporation or organization)

2100, 330 - 5th Ave. SW Calgary, Alberta, Canada T2P 0L4
(Address of principal executive offices)

Mr. Myunghuhn Yi, President & CEO
2100, 330 - 5th Ave. SW Calgary, Alberta, Canada T2P 0L4
myunghuhn.yi@harvestenergy.ca
403-268-3189
(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

Securities registered or to be registered pursuant to Section 12(b) of the Act.
(none)

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)

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.

Common shares as of December 31, 2013: 386,078,649

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

[ ] Yes [X] No

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

[ ] Yes [X] No

Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 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.

[X] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

[ ] Yes [ ] No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

[ ] Large accelerated filer [ ] Accelerated filer [X] Non-accelerated filer

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

[ ] U.S. GAAP
[X] International Financial Reporting Standards as issued by the International Accounting Standards Board
[ ] Other

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.

[ ] Item 17 [ ] Item 18

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

[ ] Yes [X] No

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GLOSSARY OF TERMS

In this annual report, the following terms shall have the meanings set forth below, unless otherwise indicated.

Certain other terms used herein but not defined herein are defined in SEC regulations and, unless the context otherwise requires, shall have the same meanings herein as in SEC regulations.

"6.40% Debentures Due 2012" means the 6.40% convertible unsecured subordinated debentures of the Corporation due October 31, 2012, which were assumed by the Corporation from VERT on February 3, 2006 pursuant to the plan of arrangement under the ABCA by which the Corporation merged with VERT.

"7.25% Debentures Due 2013" means the 7.25% convertible unsecured subordinated debentures of the Corporation due September 30, 2013.

"7.25% Debentures Due 2014" means the 7.25% convertible unsecured subordinated debentures of the Corporation due February 28, 2014.

"7.50% Debentures Due 2015" means the 7.50% convertible unsecured subordinated debentures of the Corporation due May 31, 2015.

"67/8% Senior Notes" means the Corporation's US $500 milion 67/8% Senior Notes due October 1, 2017.

"2 1/8% Senior Notes" means the Corporation's US $630 million 21/8% Senior Notes due May 14, 2018.

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

"APEGA" means the Association of Professional Engineers and Geoscientists of Alberta.

"BlackGold" means the BlackGold operating segment, with a core focus on the exploration and development of the BlackGold oil sands assets acquired from KNOC on August 6, 2010.

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

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

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

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

"Corporation" means Harvest Operations Corp.

"Credit Facility" means the $1 billion revolving credit facility, as amended, provided by a syndicate of lenders to Harvest Operations as more fully described in Item 10C "Material Contracts" and in note 12 of the Corporation's audited consolidated financial statements for the year ended December 31, 2013 under Item 18 in this annual report.

"Debentures" means, collectively, the 6.40% Debentures Due 2012, the 7.25% Debentures Due 2013, the 7.25% Debentures Due 2014 and the 7.50% Debentures Due 2015.

"Debenture Indenture" means (i) the trust indenture dated January 29, 2004 among Harvest Operations and Valiant Trust Company, as trustee, providing for the issue of debentures, as supplemented by the third supplemental indenture dated November 22, 2006 in respect of the 7.25% Debentures Due 2013, in respect of the fourth supplemental indenture dated February 1, 2007 in respect of the 7.25% Debentures Due 2014 and in respect of the fifth supplemental indenture dated April 25, 2008 in respect of the 7.50% Debentures Due 2015 and (ii) the trust indenture dated January 15, 2003 between VERT and Computershare Trust Company of Canada as trustee, providing for the issue of debentures, as supplemented by the first supplemental indenture dated October 20, 2005 in respect of the 6.40% Debentures Due 2012.

"Downstream" means the Corporation's 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 52 gasoline outlets, 3 commercial cardlock locations, a retail heating fuels business and a commercial and wholesale petroleum products business, all located in the Province of Newfoundland and Labrador.

"EPC" means engineering, procurement and construction.

"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 Harvest or an Operating Subsidiary retaining a residual interest in such Properties.

"Future Net Revenue" means the estimated net amount to be received with respect to the development and production of reserves computed by deducting, from estimated future revenues, estimated future royalty obligations, costs related to the development and production of reserves and abandonment and reclamation costs (corporate general and administrative expenses and financing costs are not deducted).

“GLJ” means GLJ Petroleum Consultants Ltd., an independent oil and natural gas reserves evaluator of Calgary, Alberta.

“GAAP” means generally accepted accounting principles.

“Gross” means:

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

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

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

“Harvest Board” means the board of directors of Harvest Operations.

“Harvest” and **“Harvest Operations”** means Harvest Operations Corp., a corporation amalgamated under the laws of the Province of Alberta.

“Independent Reserves Evaluator” means GLJ, who evaluated the crude oil, natural gas liquids and natural gas reserves of Harvest and the Operating Subsidiaries as at December 31, 2013, in accordance with the standards contained in Rule 4–10 of Regulation S–X.

“IFRS” means International Financial Reporting Standards as issued by the International Accounting Standards Board.

“KNOC” means Korea National Oil Corporation.

“KNOC Canada” means KNOC Canada Ltd., a corporation incorporated under the laws of the Province of Alberta.

“MEC” means Macquarie Energy Canada Ltd.

“Net” means:

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

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

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

“Note Indenture” means the trust indenture made as of October 4, 2010 between U.S. Bank National Association as trustee thereunder and Harvest Operations, providing for the issuance of the 67/8% Senior Notes.

“Operating Subsidiaries” means Redearth Partnership (prior to September 30, 2010), Breeze Resource Partnership, Breeze Trust No. 1, Breeze Trust No. 2, and Hay River Partnership, each (other than Redearth Partnership with respect to which the Corporation held 60% interest prior to its dissolution) direct or indirect wholly-owned subsidiary of the Corporation, and "Operating Subsidiary" means any of them.

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

“Production” means, with respect to the Upstream operations the produced petroleum, natural gas and natural gas liquids attributed to the Properties and with respect to the Downstream operations, the production of refined petroleum products at the Refinery.

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

“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.

“Related Party Loans” means the subordinated loan agreement with Ankor E&P Holdings Corp. (“ANKOR”), a 100% owned subsidiary of KNOC, entered into on August 16, 2012 with a maximum borrowing limit of US$170 million due October 2, 2017 at a fixed interest rate of 4.62% per annum and the subordinated loan agreement with KNOC, Harvest’s sole shareholder, entered into on December 30, 2013 with a maximum borrowing limit of $200 million due December 30, 2018 at a fixed rate of 5.3% per annum.

“Reserves Report” means the reports prepared by the Independent Reserve Evaluators evaluating the crude oil, natural gas liquids and natural gas reserves of Harvest and the Operating Subsidiaries as at December 31, 2011, in accordance with the standards contained in the COGE Handbook and the reserve definitions and other requirements contained in NI 51-101 and SEC regulations.

“SEC” means the United States Securities and Exchange Commission.

“Senior Unsecured Credit Facility” has the meaning ascribed thereto under the heading “Senior Unsecured Credit Facility” in note 13 of the Corporation’s audited consolidated financial statements for the year ended December 31, 2013 under Item 18 in this annual report.

“Supply and Offtake Agreement” or **“SOA”** means the supply and offtake agreement dated October 19, 2006 and as amended October 12, 2009 entered into between North Atlantic and Vitol Refining, S.A. (“Vitol”).

“Supply and Offtake Agreement (2011)” or **“SOA (2011)”** means the supply and offtake agreement dated October 11, 2011 and as amended on December 19, 2011, April 19, 2012 and July 23, 2012 entered into between North Atlantic and MEC the terms of which are summarized under Item 10C "Material Contracts".

“Trust” means Harvest Energy Trust.

“Trust Unit” means a trust unit of the Trust and unless the context otherwise requires means ordinary Trust Units of the Trust.

“Upstream” means Harvest’s petroleum and natural gas segment, consisting of the exploitation, production and subsequent sale of petroleum, natural gas and natural gas liquids in Alberta, Saskatchewan and British Columbia.

“U.S. GAAP” means accounting principles generally accepted in the United States.

“VERT” means Viking Energy Royalty Trust, a trust established under the laws of the Province of Alberta, wholly owned by the Trust.

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

ABBREVIATIONS AND CONVERSIONS

In this annual report, the following abbreviations have the meanings set forth below:

/d	Per day
3-D	Three dimensional
AECO	AECO "C" hub price index for Alberta natural gas
°API	The measure of the density or gravity of liquid petroleum products
bcf	Million cubit feet
boe(1)	Barrel of oil equivalent on the conversion factor of 6 mcf of natural gas to one bbl of oil
bbl	Barrel
bbls	Barrels
Brent	
EOR	Enhanced oil recovery
GHG	Greenhouse gas
GJ	Gigajoule
H2S	Hydrogen sulfide gas
Mbbls	Thousand barrels
Mboe	Thousand barrels of oil equivalent
mcf	Thousand cubic feet
MMboe	Million barrels of oil equivalent
MMbbls	Million barrels
MMcf	Million cubic feet
NGLs	Natural gas liquids
NOx	The general oxides of nitrogen (NO, NO_2 , N_2O_2 , etc.)
RBOB	Reformulated blendstock for oxygenate blending
SAGD	Steam-assisted gravity drainage is an enhanced oil recovery technology for producing heavy crude oil and bitumen
SOx	The general oxides of sulfur (SO_2 , SO_3 , etc.)
WTI	West Texas Intermediate, the reference price in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
$000	Thousands of dollars

(1) 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.

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

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this annual report 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: "budget", "outlook", "forecast", "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. Harvest 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 report should not be unduly relied upon. These statements speak only as of the date of this annual report or as of the date specified in the documents incorporated by reference into this annual report, as the case may be.

In particular, this annual report, and the documents incorporated by reference herein, contains forward-looking statements pertaining to:

- expected financial and operational performance in future periods, including but not limited to, production volumes, refinery throughput volumes, royalty rates, operating costs, commodity prices, general and administrative costs, refinery utilization rates and results from its price risk management activities;
- expected increases or decreases in revenue, net income and cash flows attributable to development and production activities;
- expectations regarding the development and production potential of Upstream and BlackGold properties;
- reserves estimates, ultimate recoverability of reserves and estimates of the present value of Harvest's future net cash flows;
- estimated capital expenditures,
- factors upon which to decide whether or not to undertake a capital project;
- future sources of funding, debt levels and availability of committed credit facilities;
- future allocation of funding to various activities;
- plans to make acquisitions and dispositions, and expected synergies from acquisitions made;
- possible financial and operational impact from planned dispositions;
- possible commerciality of exploration and development projects;
- the ability to achieve the maximum capacity from the BlackGold central processing facilities;
- expected timing, cost and associated impact of facility turnaround and maintenance;
- treatment under government regulatory regimes including without limitation, royalty, environmental and tax regulations;
- ultimate recoverability, either from intended use or from sale, of the Harvest's assets;
- competitive advantages and ability to compete successfully; and
- global demand and supply of crude oil, natural gas, bitumen, refined products and other related products.

With respect to forward-looking statements contained in this annual report and the documents incorporated by reference herein, Harvest has made assumptions regarding, among other things:

- future oil and natural gas prices and differentials among light, medium and heavy oil prices;
- future refining margins, including but not limited to refined product prices, feedstock prices, sour crude differentials, freight costs, Renewable Identification Numbers ("RINs") cost, and yield mix;
- Harvest's ability to conduct its operations and achieve results of operations as anticipated;
- Harvest's ability to achieve the expected results from its development plans and sustaining maintenance programs;
- the cost and time required to complete the BlackGold project;
- the continued availability of adequate cash flow and debt and/or equity financing to fund Harvest's capital and operating requirements as needed;
- Harvest's ability to obtain financing with favorable terms;
- the general continuance of current or, where applicable, assumed industry conditions;
- the general continuation of assumed tax, royalty and regulatory regimes;
- the accuracy of the Corporation's reserves;
- the ability to obtain equipment in a timely manner to carry out development and other capital activities;
- the ability to market oil and natural gas successfully to current and new customers;
- the cost of expanding Harvest's property holdings;
- the impact of increasing competition;
- the ability to add production and reserves through development and exploitation activities; and

- the ability to produce low sulphur diesel and gasoline, jet fuel, furnace oil, and other refined products that meet customer specifications.

Some of the significant risks and uncertainties that could affect Harvest's future results and could cause results to differ materially from those expressed in forward-looking statements include but is not limited to:

- volatility of commodity prices, especially the price differentials between light oil and heavy oil and the refining margins;
- uncertainties in the estimation of reserves;
- costs associated with developing and producing Upstream and BlackGold reserves, and operating the Downstream business;
- outages and disruptions to Harvest's operations due to operational issues, severe weather conditions, accidents or natural hazards;
- difficulties encountered to complete and commission the BlackGold project;
- difficulties encountered in delivering Upstream and Downstream products to commercial markets;
- difficulties encountered during the drilling for and production of crude oil, natural gas, NGLs, bitumen and other related products;
- difficulties encountered in the integration of acquisitions;
- uncertainties around realizing the value of acquisitions;
- uncertainties around Harvest's ability to attract capital;
- interest rate and foreign currency fluctuations;
- non-performance risks associated with Harvest's counterparties;
- changes in, or the introduction of, new government laws and regulations relating to the crude oil and natural gas business including without limitation, tax, royalty and environmental law and regulation;
- the extent and timing of decommissioning liabilities and environmental remediation obligations;
- liabilities stemming from accidental damage to the environment;
- adverse changes in the economy generally, such as global demand and supply for commodities;
- the impact of technology on operations and developments of Harvest's assets;
- loss of the services of any of Harvest's senior management or directors;
- the impact of competition; and
- labour and material shortages.

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 assumptions and factors are not exhaustive. The forward-looking statements contained in this annual report and the documents incorporated by reference herein are expressly qualified by this cautionary statement. Except as required by law, Harvest Operations does not undertake any obligation to publicly update or revise any forward-looking statements and readers should also carefully consider the matters discussed under Item 3D "Risk Factors".

ADDITIONAL GAAP MEASURES

Harvest uses "operating income (loss)", an additional GAAP measure that is not defined under IFRS hereinafter also referred to as "GAAP". The measure is commonly used for comparative purposes in the petroleum and natural gas and refining industries to reflect operating results before items not directly related to operations. Harvest uses this measure to assess and compare the performance of its operating segments.

NON-GAAP MEASURES

Throughout this annual report, Harvest has referred to certain measures of financial performance that are not specifically defined under U.S. GAAP or IFRS such as "operating netbacks", "operating netback prior to/after hedging", "gross margin (loss)", "refining margins", "average refining gross margins", "cash contribution (deficiency) from operations", "total debt", "total capitalization", "Annualized EBITDA", "senior debt to Annualized EBITDA", "Annualized EBITDA to interest expense", "total debt to Annualized EBITDA", "senior debt to total capitalization", and "total debt to total capitalization".

“Operating netbacks” are reported on a per boe basis and used extensively in the Canadian energy sector for comparative purposes. “Operating netbacks” include revenues, operating expenses, transportation and marketing expenses, and realized gains or losses on risk management contracts. “Gross margin (loss)”or “refining margins” are 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. “Average refining gross margin” is calculated based on per barrel of feedstock throughput. “Cash contribution (deficiency) from operations” is calculated as operating income (loss) adjusted for non-cash items. This measure demonstrates the ability of the each segment of Harvest to generate cash from our operations necessary to repay debt, make capital investments, and fund the settlement of decommissioning and environmental remediation liabilities. “Total debt”, “total capitalization”, and “Annualized EBITDA” are used to assist management in assessing liquidity and Harvest’s ability to meet financial obligations. “Senior debt to Annualized EBITDA”, “total debt to Annualized EBITDA”, “Annualized EBITDA to interest expense”, “senior debt to total capitalization” and “total debt to total capitalization” are terms corresponding to defined terms in the Credit Facility agreement for the purpose of calculation of our financial covenants. These non-GAAP measures do not have any standardized meaning prescribed by GAAP and may not be comparable to similar measures used by other issuers. The determination of these non-GAAP measures have been illustrated throughout this annual report, with reconciliations to IFRS measures and/or account balances, except for Annualized EBITDA and cash contribution (deficiency) which are shown below.

Annualized EBITDA

The measure of Consolidated EBITDA (hereinafter referred to as “Annualized EBITDA”) used in the Credit Facility agreement was defined as earnings before finance costs, income tax expense or recovery, DD&A, exploration and evaluation costs, impairment of assets, unrealized gains or losses on risk management contracts, unrealized gains or losses on foreign exchange, gains or losses on disposition of assets and other non-cash items. The following is a reconciliation of Annualized EBITDA to the nearest GAAP measure, net loss:

	December 31, 2013	December 31, 2012	December 31, 2011
Net loss	**(781.9)**	(721.0)	(105.4)
DD&A	**612.8**	688.4	626.7
Finance costs	**94.2**	111.0	109.1
Income tax recovery	**(64.2)**	(81.6)	(29.8)
EBITDA	**(139.1)**	(3.2)	600.6
Unrealized (gains) losses on risk management contracts	**0.5**	1.1	(0.7)
Unrealized (gains) losses on foreign exchange	**40.8**	(1.2)	2.6
Unsuccessful exploration and evaluation costs	**11.5**	22.0	17.8
Impairment of PP&E	**483.0**	557.3	-
Gains on disposition of PP&E	**(34.1)**	(30.3)	(7.9)
Other non-cash items	**(1.7)**	(5.6)	4.7
Adjustments on acquisitions and dispositions(1)	**(15.0)**	(13.4)	6.5
Less earnings from non-restricted subsidiaries(1)	**(0.4)**	(0.8)	(1.5)
Annualized EBITDA(1)	**345.5**	525.9	622.1

(1) Annualized EBITDA is on a consolidated basis for any period, the aggregate of the last four quarters of the earnings (calculated in accordance with GAAP) and accordingly is a twelve month rolling measure which, as well, is required to be adjusted to the net income impact from acquisitions or dispositions (with net proceeds over $20 million) as if the transaction had been effected at the beginning of the period and excludes earnings attributable to the BlackGold assets and non-restricted subsidiaries.

Cash Contribution (Deficiency) from Operations

Cash contribution (deficiency) from operations represents operating income (loss) adjusted for non-cash expense items within: general and administrative, exploration and evaluation, DD&A, gains on disposition of PP&E, risk management contracts gains or losses, impairment on PP&E, and the inclusion of cash interest, realized foreign exchange gains or losses and other cash items not included in operating income (loss). The measure demonstrates the ability of Harvest’s Upstream and Downstream segments to generate cash from its operations. There are no operating activities to report for the BlackGold segment as it is under development. The most directly comparable additional GAAP measure to cash contribution (deficiency) from operations is operating income (loss) and the most directly comparable GAAP measure is cash flow from operating activities. In the table below, operating income (loss) as presented in the notes to Harvest’s consolidated financial statements is reconciled to cash contribution (deficiency) from operations below, which in turn is then reconciled to cash flow from operating activities:

	As at December 31,								
	Upstream			Downstream			Total		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Operating income (loss)	**(16.6)**	(12.7)	111.2	**(691.1)**	(680.2)	(141.5)	**(707.7)**	(692.9)	(30.3)
Adjustments:									
Operating	**0.9**	1.6	–	**(2.8)**	(5.9)	0.8	**(1.9)**	(4.3)	0.8
General and administrative	**1.7**	(1.1)	4.9	**–**	–	–	**1.7**	(1.1)	4.9
Exploration and evaluation	**11.5**	22.0	17.8	**–**	–	–	**11.5**	22.0	17.8
Depletion, depreciation and amortization	**530.0**	579.5	535.7	**82.8**	108.9	91.0	**612.8**	688.4	626.7
Gains on disposition of PP&E	**(33.9)**	(30.3)	(7.9)	**(0.2)**	–	–	**(34.1)**	(30.3)	(7.9)
Unrealized (gains) losses on risk management contracts	**0.5**	1.1	(0.7)	**–**	–	–	**0.5**	1.1	(0.7)
Impairment on PP&E	**24.1**	21.8	–	**458.9**	535.5	–	**483.0**	557.3	–
Cash contribution (deficiency) from operations	**518.2**	581.9	661.0	**(152.4)**	(41.7)	(49.7)	**365.8**	540.2	611.3
Inclusion of items not attributable to segments:									
Net cash interest paid							**72.9**	87.9	86.2
Realized foreign exchange gains							**(3.4)**	(0.1)	(6.6)
Consolidated cash contribution from operations							**289.5**	452.4	531.7
Cash income taxes							**-**	-	(0.1)
Realized foreign exchange loss on senior unsecured credit facility							**1.3**	-	-
Settlement of decommissioning and environmental remediation liabilities							**(19.6)**	(20.4)	(22.1)
Change in non-cash working capital							**(70.6)**	11.0	51.1
Cash flow from operating activities							**200.6**	442.8	560.5

PREDECESSOR PRESENTATION

On December 22, 2009, KNOC Canada purchased all of the issued and outstanding Trust Units of Harvest Energy Trust. The acquisition of all the issued and outstanding Trust Units of the Trust resulted in a change of control in which KNOC Canada became the sole unit holder of the Trust. On May 1, 2010, an internal reorganization was completed pursuant to which the Trust was dissolved and the Trust's wholly owned subsidiary and the manager of the Trust, Harvest Operations Corp., was amalgamated into KNOC Canada to continue as one corporation under the name Harvest Operations Corp. The carrying values of Harvest's assets and liabilities were determined from the existing carrying values of KNOC Canada's assets and liabilities and therefore reflect the fair values established through the purchase.

The Trust meets the definition of a predecessor as described in Exchange Act Rule 12b-2 and Securities Act Rule 405; therefore, certain historical financial information related to the Trust is included in this annual report. Accordingly, the financial information presented in this annual report for the year ended and as at December 31,2013, 2012, 2011 and 2010 is that of Harvest Operations Corp. (the successor company) while any comparative periods represent the financial information of Harvest Energy Trust (the predecessor company). As at December 31, 2009 the internal reorganization had not yet taken place; therefore, both Harvest Energy Trust and KNOC Canada existed at this date. However, KNOC Canada was incorporated on October 9, 2009 and did not have any results of operations or cash flows between October 9, 2009 and December 31, 2009, aside from capital contributions from KNOC to finance the KNOC Acquisition and cash used in the KNOC Acquisition; as such, the financial information presented for the year ended and as at December 31, 2009 is that of the Trust, unless otherwise stated, as this provides more relevant information in comparing the results of operations.

ITEM 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISERS

Not applicable.

ITEM 2. OFFER STATISTICS AND EXPECTED TIMETABLE

Not applicable.

ITEM 3. KEY INFORMATION

A. Selected Financial Information

The financial data presented below for Harvest Operations and Harvest Energy Trust is derived from the audited consolidated financial statements. Harvest adopted IFRS with a transition date of January 1, 2010. As such, the consolidated financial statements of Harvest Operations for 2013, 2012, 2011 and 2010 have been prepared in accordance with IFRS, and the consolidated financial statements of Harvest Energy Trust for 2009 were prepared in accordance with Canadian GAAP. The selected historical consolidated financial information presented below is condensed and may not contain all of the information that readers should consider. This selected financial data should be read in conjunction with the annual audited consolidated financial statements, the notes thereto and the section entitled "Item 5 Operating and Financial Review and Prospects". The amounts presented below for the year 2009 reflect the adjustments made to conform to U.S. GAAP.

In accordance with IFRS

(millions of Canadian dollars, except for per share amounts)		**2013**		**2012 (Restated) [2]**		**2011 (Restated) [2]**		**2010 (Restated) [2]**
Income statement data								
Net revenues								
Upstream	$	947.8	$	1,028.9	$	1,091.4	$	852.2
Downstream		4,416.9		4,752.1		3,302.3		3,193.3
Total	$	5,364.7	$	5,781.0	$	4,393.7	$	4,045.5
Operating loss	$	(707.7)	$	(692.9)	$	(30.3)	$	(50.3)
Net loss	$	(781.9)	$	(721.0)	$	(105.4)	$	(81.8)
Net loss per common share								
Basic and diluted	$	(2.0)	$	(1.9)	$	(0.3)	$	(0.3)
Distributions/dividends declared	$	-	$	-	$	-	$	-
Distributions/dividends declared - U.S. dollars[(1)]	$	-	$	-	$	-	$	-
Distributions declared, per common share	$	-	$	-	$	-	$	-
Balance sheet data								
Total assets	$	5,289.9	$	5,654.6	$	6,284.4	$	5,388.7
Net assets	$	1,939.2	$	2,691.9	$	3,453.7	$	3,017.0
Shareholder's capital	$	3,860.8	$	3,860.8	$	3,860.8	$	3,355.4
Temporary equity	$	-	$	-	$	-	$	-
Cash flow statement data								
Capital expenditures (including acquisitions, net of dispositions)								
Upstream	$	161.3	$	360.4	$	1,144.9	$	932.6
Downstream		52.9		54.2		284.2		71.2
BlackGold		383.4		159.4		101.2		21.1
Total	$	597.6	$	574.0	$	1,530.3	$	1,024.9
Share data								
Weighted average common shares outstanding								
Basic and diluted		386,078,649		386,078,649		377,908,587		303,005,645

(1) Translated using the average noon buying rate as disclosed in "Exchange Rate Information" under Item 3A below

(2) Restated for the adoption of IAS 19 in 2013. For more details see Note 3 of the consolidated financial statements for the year ended December 31, 2013 included in Item 18 of this annual report.

In accordance with US GAAP

(millions of Canadian dollars, except for per Trust Unit amounts)		2009
Income statement data		
Net revenues		
Upstream	$	757.4
Downstream		2,381.6
Total	$	3,139.0
Operating income (loss)	$	(603.8)
Net loss	$	(641.9)
Net loss per Trust Unit		
Basic and diluted	$	(3.7)
Distributions/dividends declared	$	164.8
Distributions/dividends declared - U.S. dollars[1]	$	144.3
Distributions declared, per Trust Unit	$	1.0
Balance sheet data		
Total assets	$	2,476.4
Net assets	$	(2,073.8)
Shareholder's capital	$	-
Temporary equity	$	2,422.1
Cash flow statement data		
Upstream	$	124.2
Downstream		43.8
Total	$	168.0
Share data		
Weighted average Trust Units outstanding		
Basic and diluted		173,785,806

[1] Translated using the average noon buying rate as disclosed in "Exchange Rate Information" under Item 3A below

EXCHANGE RATE INFORMATION

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

The exchange rate information presented below is based on the Bank of Canada noon rates. Such rates are set forth as U.S. dollars per $1.00.

The daily closing exchange rate between the Canadian dollar and the U.S. dollar on April 28, 2014 was US$0.9070

The high and low exchange rates between the Canadian dollar and the U.S. dollar for each month during the previous six months are as follows:

	High	Low
March 2014	0.9119	0.8888
February 2014	0.9130	0.8977
January 2014	0.9422	0.8952
December 2013	0.9454	0.9348
November 2013	0.9602	0.9435
October 2013	0.9724	0.9564

The average exchange rates between the Canadian dollar and the U.S. dollar for the five most recent financial years calculated by using the average of the exchange rate on the last day of each month during the period are as follows:

	Average
2013	0.9666
2012	1.0004
2011	1.0110
2010	0.9709
2009	0.8757

B. Capitalization and Indebtedness

Not applicable.

C. Reasons for the Offer and Use of Proceeds

Not applicable.

D. Risk Factors

Harvest's Upstream, BlackGold and Downstream operations are conducted in the same business environment as most other operators in the respective businesses. The risk factors set forth below have been separated into those applicable to each of the segments and those applicable to Harvest's structure.

RISKS ASSOCIATED WITH COMMODITY PRICES

Prices received for Upstream production fluctuate significantly. Volatile differentials compound the commodity price risk.

Harvest's Upstream operations are highly sensitive to crude oil prices given its oil-weighted portfolio of assets. Similar to other Canadian oil producers, Harvest has been negatively impacted by the discounted price of WTI to other international benchmarks, such as Brent. New pipelines between Cushing, OK and the Gulf Coast and higher levels of crude being railed directly to the Gulf Coast have served to reduce the bottleneck of crude oil at the Cushing, OK hub, which was traditionally the main driver for WTI differentials to Brent. The recent discounted WTI price in relation to Brent have resulted from a bottleneck of light crude oil at the Gulf Coast with limited ability of the Gulf Coast refineries to process increased amounts of light crude oil and because of export restrictions on U.S. crude oil to international markets other than Canada. The forecast WTI discounts will likely continue to encourage rail shipments of light sweet crude from the Bakken formation. Favorable crude oil transportation economics could provide incentive to continue expanding rail capacity to the U.S. East and West coasts and to expand exports from the U.S. Gulf Coast to Canada. These expansions would provide additional outlets for rising U.S. and western Canadian crude oil production. However, light sweet crude oil supply to the U.S. Gulf Coast may still exceed take-away capacity in the near future. As a result, larger price discounts for U.S. crude oil production versus alternate world crudes, such as greater WTI discounts to Brent, may be needed to encourage Gulf Coast refiners to process the increased supplies. In addition to the WTI – Brent discount, Harvest has been experiencing wide and volatile differentials between the selling price it receives for its light oil and heavy oil production and WTI. Heavy oil generally receives lower market prices than light crude due to quality differences. However, the light oil and heavy oil price differential widened significantly in the past two years, primarily due to supply and demand imbalances caused by growing U.S. light crude oil production, bottlenecks at the Gulf Coast refineries and pipeline constraints between Canada and the U.S. There is continuous pressure on the price spread between light and heavy crudes to discourage displacing heavier crudes with increasing volumes of light crude. The magnitudes of the future differentials are uncertain. As 60% of Upstream's crude oil production is in heavy oil, continued widening of these differentials could have a significant negative impact on Harvest.

Even though the prices Harvest receives for its Upstream crude oil (and natural gas) production are referenced to U.S. dollar benchmark prices, Harvest receives the majority of its revenues in Canadian dollars. As such, Harvest's Upstream revenue is impacted by changes in the Canadian/U.S. currency exchange rates. The strengthening of the Canadian dollar could have an adverse effect on the Corporation's revenue and cash from operating activities.

Any prolonged period of low commodity prices, especially oil prices, could result in deterioration of Harvest's liquidity and profitability, which may lead to a decision by Harvest to suspend production and/or to curtail development projects. Suspension of production could result in a corresponding substantial decrease in revenues and earnings, which in turn could materially impact Harvest's liquidity. Harvest could also be exposed to significant additional expense as a result of failure to meet certain commitments relating to development and production activities. Furthermore, low commodity prices could also lead to reserve write-downs and impairment of oil and gas assets.

The Downstream refining margins fluctuate significantly, reflecting the volatility experienced in both the feedstock costs and refined products prices.

The 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 prices at which Harvest is able to sell refined products. In recent years, the market prices for crude oil and refined products have fluctuated substantially. These prices depend on a number of factors beyond Harvest's control, including the supply and demand for crude oil, refined products, renewable fuels and RINs, 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 and their price;
- 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;
- actions of other crude oil producing regions, such as OPEC;
- government regulations including changes in fuel specifications required by environmental and other laws, such as the RINs requirement;
- local factors including market conditions and the operations of other refineries in the markets in which Harvest competes; and
- the development and marketing of competitive alternative fuels.

Generally, fluctuations in the price of gasoline and other refined products are correlated with fluctuations in the price of crude oil; however, the prices for crude oil and prices for refined products can fluctuate in different directions as a result of worldwide market conditions. Further, the timing of the relative movement in prices as well as the magnitude of the change could significantly influence refining margins as could price changes occurring during the period between purchasing crude oil feedstock and selling the respective refined products. The Refinery purchases all of its crude oil feedstock at prices that fluctuate with worldwide market conditions and this could significantly impact Downtream's earnings and cash flows. The Refinery also purchases refined products from third parties for sale to its customers and price changes during the period between purchasing and selling these products could also have a material adverse effect on Harvest's business and results of operations, as well as its financial condition and cash from operating activities.

It can be reasonably expected that Downstream results will fluctuate over time and from period to period. Any prolonged period of low refining margins could result in deterioration of Harvest's liquidity and profitability, which may lead to a decision by the Corporation to suspend refinery operation and/or to curtail development projects. Suspension of operation could result in a corresponding substantial decrease in revenues and earnings, which in turn could materially impact Harvest's liquidity. Declining refining margins and/or unfavorable refining margin outlook could also lead to impairment of Harvest's Downstream assets and the Corporation's earnings could be adversely impacted (such as the impairment charge recorded in 2013 and 2012 for Harvest's Downstream assets). There can be no assurance that further decline in refined product margins will not result in additional impairment charges at some future dates.

Power expenses form a significant portion of Harvest's operating costs. Harvest is subject to risks associated with changes in electricity prices.

As a result of the deregulation of the electrical power system in Alberta, electrical power prices have been set by the market based on supply and demand and electrical power prices in Alberta have been volatile. To mitigate the Corporation's exposure to the volatility in electrical power prices, it may enter into fixed priced forward purchase contracts for a portion of the Corporation's electrical power consumption in Alberta. In respect of the operations in British Columbia, Saskatchewan, Newfoundland and Labrador, the power systems are regulated and as such, electrical power costs are not subject to significant volatility. However, there can be no certainty that these power systems will not deregulate in the future.

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

RISKS ASSOCIATED WITH UPSTREAM OPERATIONS

The Upstream operations are subject to a number of operational risks and natural hazards.

The Upstream business includes the drilling and completion of wells, the construction of associated infrastructures, the operations of crude oil and natural gas wells, equipment and facilities, the transportation, processing and storing of petroleum products, and the reclamation and abandonment of properties. These activities are subject to operational and natural hazards such as blowouts, explosions, fire, flooding, gaseous leaks, equipment failures, migration of harmful substances, spills, adverse weather conditions, environmental damage, trespass, malicious acts, unexpected accidents, natural disasters and other dangerous conditions. These incidents could result in damage to Harvest's assets, operational interruptions, suspension of development activities, personal injury or death.

Harvest's corporate environmental health and safety manual has a number of specific policies to minimize the occurrence of incidents, including emergency response should an incident occur. If areas of higher risk are identified, Harvest will undertake to analyze and recommend changes to reduce the risk including replacement of specific infrastructure; however, there can be no assurance that such measures will prevent against harmful incidents. Harvest 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 Corporation may become liable for damages arising from such events against which it cannot insure, which it may elect not to insure or that may result in damages in excess of existing insurance coverage. Costs incurred to repair such damage or pay such liabilities would reduce Harvest's cash flow. The occurrence of a significant event against which the Corporation is not fully insured could have a material adverse effect on Harvest's financial position, operating results and cash flows.

The Upstream's exploration and development activities may not yield anticipated production, and the associated cost outlay may not be recovered.

The Upstream's exploration and development activities may not yield the intended production or the associated costs to meet production targets may exceed the cash flows from such production. Either case could result in adverse impact to Harvest's future financial condition, cash flows and operating results. There are risks and uncertainties around the ability to commercially produce oil or gas reserves, to meet target production levels, and to complete the activities on schedule and on budget. Seismic data and other exploration technologies Harvest uses do not provide conclusive proof prior to drilling a well that crude oil or natural gas is present or may be produced economically. Even if production is present, Harvest may not be able to achieve or sustain production targets should reservoir production decline sooner than expected. The costs of drilling, completing and tying-in wells are often uncertain, and drilling activities may be extended, delayed or cancelled due to many factors, including but not limited to:

- inability to access drilling locations;
- failure to secure materials, equipment and qualified personnel to perform the activities;
- increased costs of oilfield services;
- delay caused by extreme weather conditions;
- changes in economic conditions, such as commodity prices;
- encountering unexpected formations or pressures;

- blowouts, wellbore collapse, equipment failures and other accidents;
- craterings and sour gas releases;
- accidents and equipment failures;
- uncontrollable flows of oil, natural gas or well fluids; and
- environmental risks.

The markets for crude oil, natural gas, NGLs and related products depend upon available capacity to refine crude oil and process natural gas, pipeline capacity to transport the products to customers, and other factors beyond the Corporation's control.

Harvest's ability to market its production depends upon numerous factors beyond the Corporation's control, including:

- the availability of capacity to refine crude oil;
- the availability of natural gas processing capacity, including liquids fractionation;
- the availability of pipeline capacity;
- the availability of diluents to blend with heavy oil to enable pipeline transportation;
- the effects of inclement weather; and
- changes in regulations.

In the past couple of years, producers are increasingly utilizing rail as an alternative transportation method. Following some major rail accidents, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying oil and gas products. Recommendations include the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. It is expected that more stringent regulations will be put in place to govern rail transportation, which may reduce the ability of railway lines to alleviate pipeline capacity issues and increase rail transportation costs.

Because of these factors, Harvest may be unable to market all of the crude oil, natural gas and related products it is capable of producing or to obtain favorable prices for its production.

Absent capital reinvestment or acquisition and development, production levels and cash flows from crude oil and natural gas properties will decline over time.

Harvest's cash from operating activities, absent commodity price increases or cost effective acquisition and development activities of properties, will decline over time in a manner consistent with declining production from typical crude oil and natural gas reserves. Accordingly, absent additional capital investment from other sources, production levels and reserves attributable to Harvest's properties will decline.

Harvest's future reserves and production, and therefore Harvest's cash flows, will be highly dependent on the Corporation's access to acquisition, exploration and development capital and success in exploiting its resource base and acquiring additional reserves. Without reserves additions through acquisition or exploration and development activities, Harvest's reserves and production will decline over time as reserves are produced. There can be no assurance that Harvest will be successful in exploring for developing or acquiring additional reserves on terms that meet its investment objectives. Also, Harvest may not have sufficient capital resources to invest in acquisition and development activities.

If the operators of Harvest's joint venture properties fail to perform their duties properly, production may be reduced and proceeds from the sale of production may be negatively impacted.

Continuing production from a property and, to a certain extent, the marketing of production 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 maintains operative control over the majority of its properties, there is no guarantee that the Corporation will remain the operator of such properties or that the Corporation will operate other properties that it may acquire.

Defects in title may defeat Harvest's claims to certain properties.

Although 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 Harvest's claim to certain properties. If Harvest claims to certain properties are defeated, Harvest's entitlement to the production and reserves associated with such properties could be jeopardized, which could have a material adverse effect on the Corporation's financial condition and results of operations.

Harvest's properties may be subject to aboriginal claims and treaty rights.

In Western Canada, aboriginal groups have filed claims in respect of aboriginal title and rights in certain areas against the Governments of Canada, Alberta and British Columbia, and certain government bodies. No certainty exists that any lands currently unaffected by claims brought by aboriginal groups will remain unaffected by future claims; if a claim arose and was successful, such claim may affect the ability to obtain approvals on a timely basis, or at all, and dependent on the nature of the claim, cause a material adverse effect on Harvest's business, financial condition and results of operations. In addition, due to traditional lands claims and and treaty rights, aboriginal consultation on surface activities is required and may result in timing uncertainties or delays of future development activities, which, if significant, could have a material material adverse effect on the development of Harvest's affected properties.

RISKS ASSOCIATED WITH RESERVES ESTIMATES

The reservoir and recovery information in reserves report are estimates and actual production and recovery rates may vary from the estimates and the variations may be significant.

The reserves and recovery information contained in the Reserves Report prepared by the Independent Reserves Evaluator are complex estimates and the actual production and ultimate reserves recovered from the Corporation's properties may differ. There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves, including many factors beyond the Corporation's control. The reserves data, as disclosed in the "Reserves and Other Oil and Gas Information" section of Item 4B, represents estimates only. In general, crude oil and natural gas reserves and the future net cash flows are based upon a number of variable factors and assumptions, such as commodity prices, future operating and capital costs, historical production from the properties, initial production rates, production decline rates, infrastructure availability and the assumed effects of regulation by governmental agencies (including regulations related to royalty payments), all of which may vary considerably from actual results. All such estimates are to some degree uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected there from, prepared by different evaluators or by the same evaluators at different times, may vary substantially. Harvest's actual production, revenues, royalties, taxes, operating expenditures, abandonment costs and development costs with respect to the Corporation's reserves may vary from such estimates, and such variances could be material.

Harvest's proved reserves and probable reserves include undeveloped reserves that require additional capital to bring them on stream, see Item 5B in this annual report. Reserves may be recognized when plans are in place to make the required investments to convert these undeveloped reserves to producing. Circumstances such as a prolonged decline in commodity prices or poorer than expected results from offsetting (Harvest's or Industry's) drilling activities could cause a change in the development plans, which could lead to a material change in the reserve estimates.

Estimates with respect to reserves and resources that may be developed and produced in the future are sometimes based upon volumetric calculations, probabilistic methods and upon analogy to similar types of reserves or resources, rather than simply extrapolating actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves or resources based upon production history will result in variations, which may be material, in the estimated reserves or resources.

The reserves value of Harvest's properties as estimated by the Independent Reserves Evaluator is based in part on cash flows to be generated in future years as a result of future capital expenditures. The reserves value of the properties as estimated by the Independent Reserves Evaluator may not be realized to the extent that such capital expenditures on the properties do not achieve the level of success assumed in such engineering reports.

Prices paid for acquisitions are based in part on reserves report estimates and the assumptions made in preparing the reserves report are subject to change as well as geological and engineering uncertainty.

The prices paid for acquisitions are based, in part, on engineering and economic assessments made by the Independent Reserves Evaluator in related reserves report. 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 commodity prices, 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 Harvest's control. In particular, the prices of and markets for crude oil and natural gas may change from those anticipated at the time of making such acquisitions. In addition, as discussed above, all engineering assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than those currently attributed to Harvest's properties.

RISKS ASSOCIATED WITH DOWNSTREAM OPERATIONS

The Refinery is a single train integrated interdependent facility which could experience a major shutdown caused by an accident or by severe weather. These potential disruptions may reduce or eliminate Harvest's cash flow.

The Refinery is a single train integrated and interdependent facility which could be forced to shut down, partially or in full, by an accident in one of the units, fire, leakages, spills, extreme weather conditions, other natural disaster, or other unplanned incidents. A shutdown of one part of the Refinery could significantly impact the production of refined products and may reduce, and even eliminate, cash flows. Any one or more of the Refinery's processing units may encounter unexpected or extended downtime for repair for damages caused by the event or identified during the outage. The time required to complete the work may extend the duration of the outage or take longer than anticipated, and the restoration of operations may otherwise involve unanticipated delay. 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 Harvest's business and results of operations, as well as its financial condition and cash from operating activities. An extremely severe incident could result in permanent damage beyond repair, which could lead to curtailment of operations.

Harvest's Downstream operations are subject to hazards which may result in personal injury, damage to Harvest's property and/or the property of others along with significant liabilities.

Harvest's Downtream operations, including the operation of the refinery, terminals, marine division, pipelines, storage tanks, and other distribution facilities and service stations, are subject to hazards and inherent risks such as fires, natural disasters, explosions, spills and mechanical failure of the equipment or third-party facilities, any of which can result in personal injury claims as well as damage to Harvest's properties and the properties of others. While Harvest carries property and casualty, the Corporation does not maintain insurance coverage against all potential losses, and could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on Harvest's business and results of operations, as well as its financial condition and cash from operating activities, as the Corporation 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. In addition, unanticipated costs or reduced operating income may be resulted from any of these incidents, which may further impact Harvest's profitability and liquidity.

Downstream operates in environmentally sensitive coastal waters where tanker operations are closely regulated by federal, provincial and local agencies and monitored by environmental interest groups. Transportation of crude oil and refined products over water involves inherent risk and subjects North Atlantic to the provisions of Canadian federal laws and the laws of the Province of Newfoundland and Labrador. Among other things, these laws require North Atlantic to demonstrate its capacity to respond to a "worst case discharge" to a maximum 10,000 metric tonne oil spill. Harvest has contracted the Eastern Canada Response Corporation to supplement Harvest's resources to achieve this response capacity. 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 Harvest may be subject to a significant liability in connection with a discharge. Downstream's marine division manages vessel traffic to the Refinery and works with regulatory authorities on measures to prevent and mitigate the risk of oil spills and other marine related matters. The marine division has two tugboats to assist in berthing and unberthing tankers at Harvest's dock with one tugboat equipped with firefighting 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.

Harvest has in the past operated service stations with underground storage tanks and currently operates 52 retail gasoline stations and 3 commercial cardlock locations with underground storage tanks in the Province of Newfoundland and Labrador. Harvest is required to comply with provincial regulations governing such storage tanks in the Province of Newfoundland and Labrador and compliance with these requirements can be costly. The operation of underground storage tanks also poses certain other risks, including damages associated with soil and groundwater contamination. Leaks from underground storage tanks which may occur at one or more of Harvest's service stations, or which may have occurred at previously operated service stations, may impact soil or groundwater and could result in fines or civil liability. While Harvest maintains insurance in respect of such risks, there are no assurances that such insurance will be adequate to fully compensate for any liability Harvest may incur if such risks were to occur.

Harvest continues to evaluate various business opportunities pertaining to the Downstream business, the outcome of the evaluation is uncertain.

Opportunities include, but are not limited to, introduction of joint venture partners, disposition in whole or in part of the Downstream segment, and various other options for future operations. An outcome or recommendation arising out of this evaluation has not been determined to date. These opportunities provide a wide spectrum of economic scenarios. Some of the opportunities may include third parties' involvement, which create higher level of uncertainties on the economic outcome because third parties' may use significantly different assumptions from Harvest's when evaluating the Downstream business. The end-decision may lead to changes in the Downstream's operations that deviate from Harvest's current intended use of the asset. As such, the ultimate recoverability of Downstream's asset is subject to risks and uncertainties.

The Refinery is subject to regular major maintenance or turnarounds, where a significant portion or the entire Refinery may be shut down. Similar to any large scale maintenance projects, the project may not complete on time or on budget, which may materially impact Harvest's cash flows and operating results.

The Refinery carries out various scales of major maintenance and turnarounds, some of which require complete shut-down. While Harvest makes every effort to properly plan and execute the scheduled maintenance, the possibility remains that capital cost overruns or schedule delays will occur as a result of fluctuating market conditions and unexpected challenges, including the availability, scheduling and costs of materials and qualified personnel; the complexities around the integration and management of contractors, subcontractors, staff and supplies; competing projects that require the same resources during the same time period; and severe weather conditions. The Refinery is a complicated facility with many integrated and interdependent components. As such, unforeseeable complications may occur or additional work may be identified during major maintenance projects that require more time and effort to complete than anticipated. Any cost overruns, schedule delays and resulting additional down days may cause material adverse effect to Harvest's cash flows and operating results. As with unplanned outages, scheduled outages could significantly impact the production of refined products and may reduce, and even eliminate, cash flow

Crude oil feedstock is delivered to the Refinery via waterborne vessels which could experience delays in transporting supplies due to weather, accidents, government regulations or third party actions.

The Refinery receives all of its crude oil and other feedstocks and its customers lift approximately 80-90% of its refined products via water borne vessels including very large crude carriers. In addition to environmental risks of handling such vessels discussed above, Harvest could experience a disruption in the supply of crude oil because of accidents, extreme weather conditions, governmental regulation or third party actions. A prolonged disruption in the availability of vessels to deliver crude oil to the Refinery and/or to deliver refined products to market would have a material adverse effect on Harvest's business and results of operations, as well as the financial condition and cash from operating activities.

Since Harvest's acquisition of North Atlantic, approximately 70% of its crude oil feedstock has been from sources in the Middle East. The Corporation does not maintain long term supply commitments with any of its crude oil producers. To the extent that crude oil producers reduce the volume of crude oil produced as a result of declining production or competition or otherwise, the business, financial condition and results of operations may be adversely affected to the extent that the Corporation is not able to find a substantial amount and similar type of crude oil. Further, the Corporation has no control over the level of development in the fields that currently produce the crude oil it processes at the Refinery nor the amount of reserves underlying such fields, the rate at which production will decline or the production decisions of the producers which are affected by, among other things, prevailing and projected crude oil prices, demand for crude oil, geological considerations, government regulation and the availability and cost of capital.

If MEC terminates the SOA (2011), Harvest's business could be adversely affected.

Under the SOA (2011), MEC sells all of the Refinery's feedstock and purchases almost all of the refined products produced. If MEC terminates the SOA (2011), Harvest would seek to enter into a similar agreement with another party that has a similar credit profile and expertise to that of MEC's. If Harvest were unable to enter into such a replacement agreement, it would be required to enter into separate agreements for the supply and financing of feedstock to the Refinery and the sale of the Refinery's refined products. No assurance can be given that Harvest will be able either to enter into an agreement similar to the SOA (2011) with another party or to enter into agreements with a number of different parties to replicate the economics of the SOA (2011). If the SOA (2011) were terminated and Harvest was unable to enter into replacement agreements, working capital requirements would likely increase and revenues and cash flows from the Refinery would likely decrease, which could have a material adverse effect on Harvest's business.

Harvest is relying on the creditworthiness of MEC for Harvest's purchase of feedstock and should their creditworthiness deteriorate, crude oil suppliers may restrict the sale of crude oil to MEC.

MEC purchases crude oil feedstock from third parties to supply North Atlantic pursuant to the SOA (2011). Should the creditworthiness of MEC deteriorate third party crude oil suppliers may reduce the sale volume to MEC, shorten the payment terms or require additional credit support. MEC may pass on additional costs to Harvest, which then may increase Downstream's feedstock costs. If MEC fails to secure sufficient amount of feedstock supplies, the Refinery operations may be disrupted. Due to the large dollar amount of credit associated with the volume of crude oil purchases, any imposition of more burdensome payment terms may have a material adverse effect on Harvest's financial liquidity which could hinder its ability to purchase sufficient quantities of crude oil to operate the Refinery at full capacity. A failure to operate the Refinery at full capacity could have a material adverse effect on its business and results of operations, as well as its financial condition and cash from operating activities.

The production of aviation fuels subjects us to liability should contaminants in the fuel result in aircraft engines being damaged and/or aircraft accidents.

The Refinery produces aviation fuels, which involves inherent risks and subjects it to the provisions of Canadian federal laws. Harvest's product quality assurance programs are extensive; however, these procedures may not be sufficient to detect and prevent contaminants from entering into the aviation fuels which could result in aircraft engines being damaged and/or aircraft accidents. While the Corporation maintains insurance in respect of such risks, there are no assurances that such insurance will be adequate to fully compensate for any liability the Corporation may incur if such risks were to occur.

Collective bargaining agreements with North Atlantic's employees and the United Steel Workers of America with respect to the Downstream operations may not prevent a strike or work stoppage and future agreements may result in an increase in operating costs.

As of December 31, 2013, 67% full-time employees and 100% of part-time employees in the Downstream operations are represented by the United Steel Workers of America pursuant to collective bargaining agreements. Upon the expiry of existing collective agreements, the Corporation 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 the Downstream business and Harvest's results of operations as well as the financial condition and cash from operating activities.

RISKS ASSOCIATED WITH BLACKGOLD OIL SANDS PROJECT

Harvest is subject to certain risks associated with the project execution and the commissioning of the SAGD operations.

Each stage of the BlackGold EPC project is subject to execution risks that are inherent in similar projects, such as failure to properly design the project scope and engineering details, difficulties around the procurement and fabrication of key modules and components, failure to carry out construction as planned, and inability to meet performance targets upon commissioning and project start-up.

The development of the BlackGold assets requires substantial capital investment. While Harvest makes every effort to properly and accurately forecast capital and operating expenditures, the possibility remains that capital cost overruns or schedule delays will occur as a result of fluctuating market conditions and unexpected challenges, including but not limited to:

- the availability, scheduling and costs of materials and qualified personnel;
- the complexities around the integration and management of contractors, subcontractors, staff and supplies;

- design and construction errors;
- changes in project scope;
- the ability to obtain the necessary regulatory approvals in various stages of the project;
- logistic issues relating to the transportation of modules across great distances;
- the availability of auxiliary infrastructures in place to support the project;
- the impact from changing government regulations and public scrutiny over oil sands development; and
- severe weather conditions.

In May 2012, Harvest amended certain aspects of its BlackGold EPC contract, including revising the compensation terms from a lump sum price to a cost reimbursable price. As such, any cost overruns and schedule delays could have the potential to affect the Corporation's future financial position and cash flows.

BlackGold is subject to government regulation. The initial phase of the project, targeting production of 10,000 bbl/d, has been approved by provincial regulators. The expansion phase of the BlackGold project which increase target production from 10,000 bbl/d to 30,000 bbl/d was approved by provincial regulators in 2013.

Harvest's estimates of performance and recoverable volumes from this project are based primarily on sample reservoir data, the results of core drilling and industry performance from other SAGD operations in similar reservoirs. Actual performance and operating results may be different as there can be no certainty that the existing and future SAGD wells will achieve or maintain the planned production rates or steam-to-oil ratio. The inability to achieve anticipated results could be due to one or all of design, facility or reservoir performance, or the presence of problematic geological features. As such, additional drilling, construction of new facilities, modification of existing facilities and additional operating expenses may be required to maintain optimal production levels. Harvest may encounter operational issues unanticipated thus far as BlackGold is Harvest's first SAGD project. Operating costs may vary considerably from expectation as they are impacted by various factors, including but not limited to, the amount and cost of labor to operate the project, the cost of diluent, catalyst and chemicals, the cost of natural gas and electricity, reliability of the facilities, repair and maintenance costs, etc. Transportation costs may be higher than planned as Harvest may depend, to a large degree, on third party facilities and infrastructure to move its bitumen. There is no assurance that Harvest will have the most cost-effective market access. Failure to meet performance targets may adversely impact Harvest's financial conditions, operating results, cash flows and ultimate recoverability of the project.

RISKS ASSOCIATED WITH HARVEST'S CAPITAL RESOURCES

Harvest must meet certain ongoing financial and operating covenants; failure to do so may result in debt repayment and consequently adverse effect on Harvest's cash flows.

Under the Credit Facility, Harvest and certain subsidiaries of Harvest Operations (designated as restricted subsidiaries) have provided the lenders security over all of the assets of Harvest Operations and of the wholly-owned restricted subsidiaries. If an event of default (as defined under the Credit Facility) has occurred the lenders may demand repayment and exercise rights under the security, including sale of the secured assets. Certain payments by Harvest or the restricted subsidiaries are prohibited upon an event of default. Harvest must meet certain ongoing financial and other covenants under each of the Credit Facility and the Note Indenture (respecting the 67/8% Senior Notes). The covenants include customary provisions and restrictions related to Harvest Operations and the restricted subsidiaries' operations and activities, and are described further for each of the Credit Facility and the Note Indenture in Item 10C "Material Contract" of this annual report. Harvest reviews the covenants regularly based on historical financial results. If the Corporation does not comply with the covenants, repayments could be required. Though Harvest continually monitors compliance with all of its covenants, there is no assurance that Harvest will be able comply with the financial and other covenants of its Credit Facility and Note Indenture or meet repayment requirements to or refinance such obligations if a default occurs. This could result in an adverse effect on Harvest's financial condition and liquidity.

Harvest may not be able to execute its capital investment projects as planned due to financial constraints.

Harvest has ongoing capital investment projects and planned projects for the future periods in all three of its operating segments. These projects compete for cash flows against each other and Harvest's other cash commitments. Harvest may not have sufficient capital resources to finance all its projects and may delay or curtail certain development projects. Any changes to Harvest's capital investment plans may further impair its ability to grow or to sustain its current operating levels, which may negatively impact Harvest's future operating results, financial position and cash flows.

Harvest current debt level and financial commitments may negatively impact the business.

Harvest's current debt levels and financial commitments may limit its financial and operating flexibility, which could have significant and adverse consequences to the business, including:

¿ an increased sensitivity to adverse economic and industry conditions;

¿ a limited ability to fund future working capital and capital expenditures, engage in future acquisitions or development activities, or to otherwise fully realize the value of assets or opportunities, because a substantial portion of the cash flows are required to service debt and other obligations;

¿ a limited ability to plan for, or react to, industry trends; and

¿ an uncompetitive position relative to Harvest's competitors whose debt and financial commitment levels are lower.

Harvest's ability to raise capital resources is subject to various risks. Failure to access future financing may result in severe liquidity issues.

Harvest's ability to raise capital resources is subject to certain risks, including disruptions in international credit markets, collapses of sovereign financial systems, global economy downturns, overall oil and gas industry conditions, credit rating downgrades, and intense competition from other debt/equity issuers. To the extent that new sources of financing becomes limited, unavailable or available on unfavorable terms, the Corporation's ability to make capital investments, maintain existing assets, meet financing commitments, repay debt may be constrained, and, as a result Harvest's business, operating results and financial conditions may be materially impacted.

Harvest is exposed to exchange rate risks from its U.S dollar denominated debts and to interest rate risks from its floating-rate debts.

Harvest's borrowings under its 67/8% Senior Notes, 21/8% Senior Notes, Related Party Loans with ANKOR and LIBOR based loans and the related interest charges are denominated in U.S. dollars. The Downstream's functional currency is in US dollars. As such, material adverse changes to the exchange rates between Canadian dollar and the U.S. dollar could negatively impact Harvest's financial conditions, cash flows and operating results.

Harvest is also exposed to interest rate risks on its Credit Facility borrowings as interest rates are determined in relation to floating market rates. Furthermore, the Corporation is exposed to interest rate risk when maturing debt is refinanced, or when new debt capital is raised. Significant increase to interest rates could result in reduced future profitability and liquidity. Increased interest rates could also cause capital projects to become uneconomical and might lead to suspension of such projects. Ultimate recoverability of capital assets may be impaired from higher interest rates.

Harvest engages in various risk management activities using derivative instruments, which inherently are subject to risks and uncertainties.

The Corporation monitors its exposure to commodity prices, interest rates and foreign exchange rates and, where deemed appropriate, utilizes derivative financial instruments and physical delivery contracts to help mitigate such risks. The utilization of derivative financial instruments may introduce significant volatility into Harvest's reported net earnings, comprehensive income and cash flows. The terms of our various hedging agreements may limit the benefit to the Corporation of commodity price increases or changes in interest rates and foreign exchange rates. The Corporation may also suffer financial loss because of hedging arrangements if:

¿ Harvest is unable to produce crude oil, natural gas or refined products to fulfill delivery obligations;

¿ Harvest is required to pay royalties based on market or reference prices that are higher than hedged prices; or

¿ counterparties to the hedging agreements are unable to fulfill their obligations under the hedging agreements.

RISKS ASSOCIATED WITH GENERAL BUSINESS

Harvest may be adversely affected by changes in laws and regulations relating to the crude oil and natural gas industry.

Harvest's operations could be impacted by changes in federal, provincial and municipal laws and regulations relating to the crude oil and natural gas and refining industry, including but not limiting to, royalty regimes, income and capital tax laws, land tenure, government incentive programs, production rates controls, safety programs and environmental acts. Changes in laws, regulations and policies could lead to direct reduction in revenue and cash flows, and/or additional compliance costs. Significant adverse changes could also result in suspension of Harvest's exploration, development and production of its oil and gas reserves or impact operations of its refinery. Government laws and regulations could be complex and subject to misinterpretation. Non-compliance may lead to significant penalties and fines, loss of licenses and permits or legal claims, all could have material effect to Harvest's financial condition, results of operations and cash flows.

Harvest's operations are subject to environmental regulation pursuant to local, provincial and federal legislation and require us to obtain and maintain regulatory approvals. A breach of such legislation may subject us to substantial liability and result in the imposition of fines as well as higher operating standards that may increase costs.

Harvest's operations and related properties are subject to extensive federal, provincial and local environmental and health and safety regulations governing, among other things, the production, processing, 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 the Corporation fails to comply with these regulations, it may be subject to administrative, civil and criminal proceedings by governmental authorities as well as civil proceedings by environmental groups and other entities and individuals. A failure to comply, and any related proceedings, including lawsuits, could result in significant costs and liabilities, penalties, judgments against us or governmental or court orders that could alter, limit or stop the operations.

Consistent with the experience of other Canadian oil and gas and refining businesses, environmental laws and regulations have raised operating costs and at times required significant capital investments in our assets. Harvest believes that its operations are materially compliant with existing laws and regulatory requirements. However, material expenditures could be required in the future to comply with evolving environmental, health and safety laws, regulations or requirements that may be adopted or imposed in the future.

Harvest operates under permits issued by the federal and provincial governments and these permits may be renewed periodically. The federal and provincial governments may make operating requirements more stringent which may require additional spending. 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 Harvest's business and results of operations as well as its financial condition and cash from operating activities.

Harvest's abandonment and reclamation obligations may increase due to changes in environmental laws and regulations.

Harvest is responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding the abandonment and reclamation of its surface leases, wells, facilities and pipelines and refinery and terminal operations at the end of their economic life as well as those for any future expansions. A breach of such legislation and/or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made. It is not possible to accurately predict the timing and the amount of the abandonment and reclamation costs due to uncertainties around numerous factors, such as regulatory requirements at the time, future labor and material costs, the extent of contamination at the site, future technology and the value of the salvaged equipment. Any adverse changes to any of these factors could result in additional costs to Harvest, which could impact Harvest's cash flows and financial conditions. In addition, in the future Harvest may determine it prudent or may be required by applicable laws, regulations or regulatory approvals to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs.

Harvest is subject to income tax assessments and re-assessment, which may result in unfavorable tax consequences.

From time to time, Harvest Operations may take steps to organize its affairs in a manner that minimizes taxes and other expenses payable with respect to the operation of the Corporation and the Operating Subsidiaries. Harvest's prior years' income tax and royalty filings are subject to reassessment by government entities. The reassessment of previous filings may result in additional income tax expenses, royalties, interest and penalties which may adversely affect the Corporation's cash flows, results from operation and financial position.

Harvest faces strong competition in various aspects of its operations, which may create constraints and negative impact to Harvest's operations.

There is strong competition relating to all aspects of the crude oil and natural gas industry. Harvest actively competes for capital, skilled personnel, new sources of crude oil and natural gas reserves, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, new customers or marketing channels, and access to lower priced feedstocks for the Refinery with a substantial number of other crude oil and natural gas organizations, many of which may have greater technical and financial resources than Harvest. In areas where access and operations can only be conducted during limited times of the year due to weather or government regulations, the competition for resources is even more intense. Constraints resulted from such competition may lead to increased cost outlay and suspension of operational and development activities, which could negatively impact Harvest's financial conditions, operating results and cash flows.

Harvest's operations and performances are heavily reliant on key personnel.

Holders of securities of Harvest will be dependent on the management of Harvest in respect of the administration and management of all matters relating to Harvest and the Operating Subsidiaries and the properties. Investors who are not willing to rely on the management of Harvest should not invest in the Corporation. In addition, the loss of key management could have an adverse effect on the Corporation. The competition for qualified personnel in Alberta and Newfoundland is intense, and there can be no assurance that Harvest will be able to continue to retain or attract the necessary personnel for the continuance of development and operation of the Corporation's business.

Harvest is subject to credit risks in its normal course of business.

Harvest enters into contractual relationships with various counterparties, the majority of which are from or related to the oil and gas and refining industry. If such counterparties do not fulfill their contractual obligations or settle their liabilities to the Corporation, the Corporation may suffer losses, may have to proceed on a sole risk basis, may have to forgo opportunities or may have to relinquish leases. While the Corporation maintains a risk management system that limits exposures to any one counterparty, losses due to the failure by counterparties to fulfill their contractual obligations may adversely affect Harvest's financial condition and liquidity.

ITEM 4. INFORMATION ON THE COMPANY

A. History and Development of the Company

Harvest Operations Corp. was incorporated under the ABCA on May 14, 2002. All of the issued and outstanding common shares of Harvest Operations are owned by KNOC. Established in 1979, KNOC is a leading international oil and gas exploration and production company wholly owned by the Government of Korea. KNOC's founding principle is to secure oil supplies for the nation of Korea by exploring for and developing oilfields and holding petroleum reserves. As at December 31, 2013, Harvest's net proved reserves represented approximately 31% of KNOC's consolidated crude oil and natural gas reserves and resources. Additionally, Harvest's crude oil and natural gas production represented 24% of KNOC's consolidated 2013 petroleum and natural gas production.

Harvest Operations manages the affairs of the Operating Subsidiaries and North Atlantic, and is responsible for providing all of the technical, engineering, geological, land management, financial, administrative and commodity marketing services relating to Harvest's Upstream and BlackGold operations.

The head and principal office of Harvest is located at Suite 2100, 330 - 5th Avenue S.W., Calgary, Alberta T2P 0L4 and the telephone number is (403) 265-1178. The registered office of Harvest is located at Suite 4500, Bankers Hall East 855 – 2nd Street S.W., Calgary, Alberta T2P 4K7.

RECENT DEVELOPMENTS

On March 14, 2013, Harvest entered into a US$400 million Senior Unsecured Credit Facility. The facility was irrevocably and unconditionally guaranteed by KNOC. Draws under the facility were made for an aggregate US$390 million, to fund the early redemptions of the 7.25% Debentures Due 2013 and 7.25% Debentures Due 2014 on April 2, 2013 and April 15, 2013, respectively. Both series of debentures were redeemed at par with the total redemption payment, including all accrued and unpaid interest up to the respective redemption dates, being $1,002.978 per $1,000 principal amount for the 7.25% Debentures Due 2013 and $1,006.5547 per $1,000 principal amount for the 7.25% Debentures Due 2014.

On May 14, 2013, Harvest issued US$630 million of senior unsecured notes due May 14, 2018 with a coupon rate of 21/8%. The notes were unconditionally and irrevocably guaranteed by KNOC. The proceeds were used to repay the Senior Unsecured Credit Facility and to early redeem, at par, the 7.50% Debentures Due 2015 on June 13, 2013. The total redemption payment, including all accrued and unpaid interest up to the redemption date, was $1,002.67 per $1,000 principal amount.

On October 18, 2013, Harvest increased the borrowing capacity of the Credit Facility from $800.0 million to $1.0 billion and extended the Credit Facility maturity date by one year to April 30, 2017.

On December 30, 2013 Harvest entered into a five-year $200 million subordinated loan facility with KNOC at a fixed interest rate of 5.3% per annum and borrowed $80.0 million thereunder. On February 28, 2014, Harvest borrowed an additional $80.0 million under the subordinated loan facility.

During 2013, Harvest disposed of certain non-core producing properties in west central Saskatchewan and Alberta for the total proceeds of approximately $173.9 million. The transactions resulted in a gain of $33.9 million, which has been recognized in the consolidated statements of comprehensive loss.

During 2013, Harvest recognized an impairment charge of $458.9 million against its Downstream's property, plant and equipment ("PP&E") due to lower than expected crack spreads and increased regulatory costs. Harvest also recorded an impairment charge of $24.1 million against its Upstream's PP&E relating to certain gas properties in Southern Alberta due to reserves write-down at year-end.

On April 15, 2014, Harvest amended its Credit Facility to accommodate the progression of partnership and joint venture arrangements for the development of Company lands. The amendments included provisions that allow the formation, operation and funding of partnerships that Harvest does not fully own, within specific parameters regarding the amount of assets and production contributed to such non-wholly owned partnership and joint venture arrangements. Limitation on distribution has been amended to allow distributions to Harvest or third parties by a joint venture partnership under specific provisions. The definitions for financial measures that are used in covenant ratios, including Consolidated EBITDA, Consolidated Total Debt and Consolidated Senior Debt have also been amended to accommodate the partnership and joint venture arrangements. In addition, the amendment removed Harvest's option to cause the BlackGold assets to be removed from the security package of the Credit Facility, effectively enabling the Company to recognize equity related to BlackGold of $457.7 million as at December 31, 2013 for purposes of Total Capitalization, and specified an incremental amount of $229.5 million to be added to Total Capitalization representing partial relief of the Downstream impairment charge incurred in 2013, effective Q1 2014.

On April 23, 2014, Harvest entered into two joint ventures with KERR Canada Co. LTD. ("KERR"). Deep Basin Partnership was established for the purposes of exploring, developing and producing from certain oil and gas properties in the Deep Basin area in Northwest Alberta. HK MS Partnership was formed for the purposes of constructing and operating a gas processing facility, which will be primarily used to process the gas produced from the properties owned by the Deep Basin Partnership. A gas processing agreement was entered by the two partnerships. Harvest contributed certain producing and non-producing properties to Deep Basin Partnership in exchange for 467,386,000 of common partnership units, while KERR contributed $100.4 million for 100,368,000 preferred partnership units. Amounts contributed by KERR will be spent by the Deep Basin Partnership to drill and develop partnership properties in the Deep Basin area. If funding from KERR is insufficient to fund the entire agreed initial multi-year development program, Harvest will fund the balance of the program from its share of partnership distributions. The preferred partnership units provide KERR certain preference rights, including a put option right exercisable after 10.5 years, whereby KERR could cause Deep Basin Partnership to redeem all its preferred partnership units. If Deep Basin Partnership does not have sufficient funds to complete the redemption obligation and after making efforts to secure funding, whether via issuing new equity, entering into a financing arrangement or selling assets, the partnership can cash-call Harvest to meet such obligation. For the HK MS Partnership, KERR contributed $22.6 million of partnership units, which represent 34.82% of the outstanding partnership units. The remaining 65.18% will be contributed by Harvest as cash is required for the construction of the gas processing facility. On the earlier of 10.5 years after the formation of the HK MS Partnership or when KERR achieves certain internal rate of return, Harvest will have the right but not the obligation to purchase all of KERR's interest for nominal consideration.

CAPITAL EXPENDITURES

The following table provides a summary of Harvest's capital expenditures per the cash flow statement for the last three years ended December 31:

($ millions)	**2013**	2012	2011
Upstream capital expenditures	**$ 322.3**	$ 447.6	$ 639.6
BlackGold capital expenditures	**382.6**	159.4	101.2
Downstream capital expenditures	**53.2**	54.2	284.2
Total capital expenditures	**758.1**	661.2	1,025.0
Acquisitions			
Business	**-**	-	509.8
Property	**13.7**	1.3	4.2
Divestitures			
Property	**(174.2)**	(88.5)	(8.7)
Net acquisition and divestiture activities	**(160.5)**	(87.2)	505.3
Net capital investment	**$ 597.6**	$ 574.0	$ 1,530.3

For details to the capital expenditures for each segment, please refer to Item 5 "Operating and Financial Review and Prospects" of this annual report.

During 2013, Harvest's Upstream business disposed of certain non-core producing properties in west central Saskatchewan and Alberta for total proceeds of approximately $173.9 million. The transactions resulted in a gain of $33.9 million, which has been recognized in the consolidated statements of comprehensive loss. In addition, Harvest's Downstream business received proceeds of approximately $0.3 million from minor dispositions.

During 2012, Harvest disposed of certain non-core producing properties in Alberta and Saskatchewan for proceeds of $88.5 million. These transactions resulted in a gain of $30.3 million, which has been recognized in the consolidated statements of comprehensive loss.

On February 28, 2011, Harvest closed the acquisition of assets from Hunt Oil Company of Canada, Inc. and Hunt Oil Alberta Inc. (collectively, "Hunt") for cash consideration of $511.0 million. KNOC provided $505.4 million of equity to fund the acquisition. Assets acquired include approximately 377,000 net acres of undeveloped land, with complementary land positions in Willesden Green, the Peace River Arch and Southern Alberta. This acquisition includes access to resource plays in the Willesden Green area of Alberta and the Horn River basin of British Columbia.

Harvest signed an EPC contract in 2010 for phase 1 of BlackGold. Under the EPC contract, a maximum of approximately $101 million of the EPC costs will be paid in equal installments, without interest, over 10 years commencing on the completion of the EPC work in 2014. As at December 31, 2013, Harvest has incurred costs of $551.7 million on the EPC contract. After the accounting impact of the deferred payment, Harvest has recorded $531.6 million of costs for the EPC contract and has recorded $730.9 million of costs on the entire project since acquiring the BlackGold assets in 2010. For further information on the BlackGold project, refer to Item 4B "Business Overview" and Item 4D "Property, Plant and Equipment" of this annual report. Please refer to Item 4D "Property, Plant and Equipment" for details regarding the Corporation's 2014 capital expenditure plan and Harvest's material properties.

B. Business Overview

Harvest is a significant operator in Canada's energy industry with three operating segments: Upstream, BlackGold and Downstream. Harvest's Upstream oil and gas and BlackGold oil sands businesses are complemented by its long-life refining business that focuses on the safe and efficient operation of a medium gravity sour-crude refinery located in the Province of Newfoundland and Labrador and the associated retail and marketing operations.

UPSTREAM

In the Upstream operations, Harvest employs a disciplined approach to acquiring, developing and operating large resource-in-place producing properties using best-in-class technologies. Harvest's Upstream operations are principally located in the Western Canadian Sedimentary Basin and material properties are described in Item 4D "Property, Plant and Equipment". Harvest has a high degree of operational control as it is the operator on properties that generate the majority of Harvest's production. The Corporation believes that this "hands on" approach allows it to better manage capital expenditures and accumulate institutional expertise in its operating regions.

IMPACT OF VOLATILITY IN COMMODITY PRICES

Harvest's operational results, liquidity 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, which are influenced by transportation constraints, weather, geopolitical and general economic conditions. Any decline in petroleum and natural gas prices could have an adverse effect on Harvest's financial condition. More details discussion on commodity price risks is included in Item 3D "Risk Factors". 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 16 of the consolidated financial statements for the year ended December 31, 2013 included in Item 18 of this annual report.

MARKETING CHANNELS

Crude Oil and NGLs

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

Natural Gas

Approximately 90% of Harvest's natural gas production is currently being sold at the prevailing daily spot market price in Western Canada. A vast majority of the remaining 10% of production receives Chicago based prices via two transportation contracts under which gas is shipped to the United States. A marginal 0.1% of production is dedicated to aggregator contracts, which are reflective of market prices and are under contract until 2015.

The following is Harvest's Upstream sales by product for each of the three years ended December 31:

($ millions)		**2013**		**2012**		**2011**
Light / medium oil sales after hedging(1)(2)	$	**363.7**	$	437.1	$	454.3
Heavy oil sales(1) (2)		**455.6**		509.4		527.4
Natural gas sales(1) (3)		**147.6**		115.7		156.9
Natural gas liquids sales(2)		**112.1**		114.5		125.5
Other(4)		**22.7**		16.8		22.8
Petroleum and natural gas sales	$	**1,101.7**	$	1,193.5	$	1,286.9
Royalties		**(153.9)**		(164.6)		(195.5)
Revenues	$	**947.8**	$	1,028.9	$	1,091.4

(1) Inclusive of the effective portion of realized gains (losses) from natural gas and crude oil contracts designated as hedges.

(2) All of Harvest's crude oil and NGLs are sold in Canada.

(3) In 2013, 10% of natural gas was delivered to a pipeline that ships to the United States (2012 – 10%; 2011 – 9%).

(4) Inclusive of sulphur revenue and miscellaneous income.

PIPELINE CAPACITY

Although pipeline expansions are ongoing, the apportionment of capacity on pipeline systems can occur from time-to-time, due to pipeline and downstream operating problems, affecting the ability to market crude oil and natural gas. Most of the current apportionments, however, are due to significant product supply which exceeds current pipeline capacity. Oil and natural gas producers in North America and, particularly in Western Canada, currently receive discounted prices for their production relative to international prices, due to constraints on the ability to transport and sell such products to international markets.

COMPETITIVE CONDITIONS, SEASONALITY, AND TRENDS

Competitive conditions are included in the description of Harvest's risk factors in Item 3D of this annual report. The exploitation and development of petroleum and natural gas reserves is dependent on physical access to production areas. Seasonal weather conditions, including freeze-up and break-up, affect such access. The seasonal accessibility increases competition for equipment and human resources during those periods.

ENVIRONMENT, HEALTH AND SAFETY ("EH&S") POLICIES AND PRACTICES

Harvest commits to conducting its operations in a manner that protects the health and safety of employees, contractors and the public, and minimizing environmental impact. Harvest's EH&S policy is designed with a primary objective to comply with industry and jurisdictional regulatory requirements. There are various components in the EH&S policies, with the core environmental components focused on prevention, remediation and reclamation of environmental impact to land, water and air. See "Environmental Regulation" section of this annual report for discussion of specific regulatory requirement. The Health and Safety components are focused on proactive measures reducing risk and eliminating hazards to employees, contractors, subcontractors and the public. Harvest is committed to an injury free workplace.

Harvest takes an active role in the Canadian Association of Petroleum Producers ("CAPP") Responsible Canadian Energy ("RCE") program. The RCE is an association-wide performance reporting program designed to track progress of the CAPP membership in environmental, health, safety, and social performance. In particular, it is a commitment by Harvest to continuously improve on parameters such as reducing injuries, decreasing air emissions, re-using and recycling of water, and minimizing our environmental footprint and impact on the land. Harvest, in comparison to other Upstream producers are below industry average on Total Recordable Injury Frequency, NOx and SOx emissions, and gas venting per BOE produced. Harvest is working towards improving the Corporation's performance on water usage and decreasing our spill frequency for 2014. These improvement efforts are not expected to materially impact Harvest's operations or operating results.

The majority of Harvest environmental expenditures relate to site remediation and asset retirement from its land use. In 2013, Harvest spent $19.6 million on the management and retirement of environmental obligations which included retirement of wells and facilities, restoration of spill sites, remediation of sites with historical contamination, and the reclamation of abandoned well sites and access roads. In 2013, Harvest had 348 active reclamation sites. Harvest received 17 reclamation certificates in 2013. In addition, Harvest completed 92 surface well abandonments which will add to the number of active reclamation sites in 2014. Efforts towards other aspects of environmental protection and controls, such as water usage, waste management, air monitoring and emission reporting are not material.

In 2013, Harvest continued to take steps to build on its existing EH&S management systems using the RCE framework for continuous improvement. This included initiating a process to formalize the environment and regulatory components of the EH&S management system. Completion of this process is expected by the end of 2014 and will result in an overall improvement in environmental stewardship and performance. The costs associated with this initiative are not expected to be material.

As part of the Certificate of Recognition ("COR") maintenance requirements, in 2013 the health and safety management system underwent its second audit in the COR process. Third party auditors evaluated the system on a set of pre-determined criteria. The results of the audit were shared with Harvest's Board and to all staff via quarterly newsletter. Areas where opportunities for improvement exist that were identified in the audit will be reviewed and action plans developed based on risk exposure to the organization. The EH&S department and Procurement group are continuing to develop and improve on our Contractor Engagement & Management System. As required, the Corporate Emergency Response Plan underwent annual review which included revising critical information within the plans and ongoing training of key response personnel at Harvest. Mandated full scale exercises were conducted in various areas of operations and information gathered during and post exercise was used to improve the Harvest Operations Corp. Incident Command System.

Harvest met all regulatory compliance obligations in 2013 including the submission of the annual National Pollutant Release Inventory, the BC Greenhouse Gas Inventory, the annual Facility Approval summary reports, the inventory of all benzene emissions from Glycol Dehydrators, the annual Caribou Protection Plans and completion of all Indian and Oil and Gas required environmental audits. In addition, Harvest continued to be diligent with its Fugitive Emission Management Program, with leak detection testing conducted at all required facilities. All repairable emission sources detected were repaired representing a reduction in GHG emissions and savings in fuel gas usage. Harvest has incurred immaterial compliance costs associated with these various programs and regulations.

CONTROLS AND REGULATIONS

The petroleum and natural gas exploration and production industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, emissions, 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. 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 Harvest is 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 based prices. It is common to sell on an index, which is published on a daily and/or monthly basis. These indices are generated from calculations that consider volume-weighted-industry-reported purchase and sales transactions. They are generated at various sales points and are reflective of the current value of the specific commodity, adjusted for quality and location differentials. While these indices tend to directionally track benchmark prices (i.e. WTI crude oil at Cushing, Oklahoma, WCS at Hardisty, Alberta, or natural gas at AECO, Alberta, or Henry Hub, Louisiana), some variances can occur due to specific market imbalances. These relationships to industry reference prices can change on a monthly or daily basis depending on the supply-demand fundamentals at each location as well as other non-related market changes such as the value of the Canadian dollar.

Although the market ultimately determines the price of crude oil and natural gas, producers are entitled to negotiate sales contracts directly with purchasers. 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. Natural gas prices are calculated at the sale points, such as the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements. As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the New York Mercantile Exchange in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

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 also 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 federal and provincial governments in Canada have established incentive programs which have included royalty rate reductions (including for specific wells), royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. However, the trend in recent years has been to eliminate these types of programs in favour of long-term programs which enhance predictability for producers. If applicable, oil and natural gas royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments.

Alberta

The Government of Alberta (the “Government”) implemented the Alberta Royalty Framework (“ARF”) effective January 1, 2011. Royalty rates for conventional oil and natural gas under the ARF are determined based on a sliding scale incorporating separate variables to account for production volumes and market prices. The maximum royalty payable for conventional oil is 40% and for natural gas is 36%. Oil sands base royalty rates start at 1%, of gross revenue, and increase for every dollar when WTI is priced above $55 per barrel to a maximum of 9% when WTI prices reach Cdn$120 per barrel or higher. Once the oil sands project has recovered specified allowed costs, the royalty payable is the higher of the gross revenue royalty based on the gross revenue royalty rate (between 1%-9%) or the net revenue royalty based on the net revenue royalty rate (between 25% to 40%). The ARF has retained the Natural Gas Deep Drilling Program (the “NGDDP”) and the Deep Oil Exploratory Well (the “DOEW”) Program with the intention to encourage the development of deeper, higher cost oil and gas reserves by offering royalty relief or credits to qualifying wells. The DOEW program is a five year program which ended on December 31, 2013 while the NGDDP is a permanent feature.

In November 2008, the Government announced the introduction of a five year program, the Transitional Royalty Plan (the “TRP”), which offers companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 meters) a one-time option, on a well-by-well basis, to reduced royalty rates for new wells for a maximum period of five years to December 31, 2013 after which all wells convert to the ARF. To qualify for this program, wells must be drilled between November 19, 2008 and December 31, 2013. This program was amended on May 27, 2010 such that no new wells were allowed to select transitional royalty rates effective January 1, 2011 and wells that have selected the transitional royalty rates had the option to switch to the new rates effective January 1, 2011.

On March 17, 2011, the Government approved the New Well Royalty Regulation providing the permanent implementation of a formerly temporary royalty program which provides for a maximum 5% royalty rate for eligible new wells for the first 12 production months or until the regulated volume cap is reached. In addition, the Government implemented certain initiatives intended to stimulate investment in emerging resources and technologies. In particular, the Government implemented the Horizontal Oil and Gas New Well Royalty Rates, retroactive to wells that commence drilling on or after May 1, 2010, to provide upfront royalty adjustments to new horizontal wells. Qualifying oil wells will receive a maximum royalty rate of 5 percent for all products with volume and production month limits set according to the depth of the well. Qualifying gas wells will also receive a maximum royalty rate of 5 percent for all products for 18 producing months, with a volume limit of 500 million cubic feet of gas equivalent production.

Saskatchewan

In Saskatchewan, the amount payable as a Crown royalty or freehold production tax in respect of crude oil depends on the type, value, quantity produced in a month and vintage. Crude oil type classifications are “heavy oil”, “southwest designated oil” or “non-heavy oil other than southwest designated oil”. Vintage categories applicable to each of the three crude oil types are old, new, third tier and fourth tier. Crude oil rates are also price sensitive and vary between the base royalty rates of 5% for all fourth tier oil to 20% for old oil. Marginal royalty rates, applied to the portion of the price that is above the base price, are 30% for all fourth tier oil to 45% for old oil.

The royalty payable on natural gas is determined by a sliding scale based on the vintage of the gas, type of gas production, quantity of gas produced in a month, and the provincial average gas price for the month. As an incentive for the marketing of natural gas produced in association with oil, a lower royalty rate is assessed than the royalty payable on non-associated natural gas. The rates and vintage categories of natural gas are similar to oil.

The Government of Saskatchewan provides a number of volume incentive programs to encourage oil and gas exploration and development in Saskatchewan. For example, a maximum royalty rate of 2.5% for Crown production and a maximum production tax rate of 0% for freehold production are applied to qualifying incentive volumes on newly drilled oil wells and exploratory gas wells.

British Columbia

The British Columbia royalty regime for oil is dependent on age and production. Oil is classified as "old", "new" or "third tier" and a separate formula is used to determine the royalty rate depending on the classification. The rates are further varied depending on production. Lower royalty rates apply to low productivity wells and third tier oil to reflect the increased cost of exploration and extraction. There is no minimum royalty rate for oil.

The British Columbia natural gas royalty regime is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a posted minimum price. Natural gas is classified as either "conservation gas" or "non-conservation gas". For non-conservation gas, the royalty rate is dependent on the date on which title was acquired from the Crown and on the date on which the well was drilled and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. The base royalty rate for non-conservation gas ranges from 9% to 15%. A lower base royalty rate of 8% is applied to conservation gas. However, the royalty rate may be reduced for low productivity wells.

The Government of British Columbia also maintains a number of royalty programs such as the Deep Royalty Credit Program, Net Profit Royalty Program, and the Infrastructure Royalty Credit Program. These programs offer either royalty credit or royalty reduction and are intended to stimulate development of British Columbia's natural gas low productivity wells.

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 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.

Alberta Regulatory Enhancement Project

The Regulatory Enhancement Project started in 2010 with the goal of creating a regulatory system that delivers clarity, predictability, certainty and efficiency. In December 2012, the Responsible Energy Development Act was passed with the intention to create a single regulator for upstream oil, gas, oil sands and coal projects in Alberta. In June 2013, the Alberta Energy Regulator ("AER") was created. The AER assumed the regulatory functions of the former Energy Resources Conservation Board and in November 2013, the AER assumed the public land and geophysical jurisdiction responsibilities from the Environment and Sustainable Resource Development ("ESRD"). The AER is expected to assume all responsibilities under the environmental and water jurisdictions from the ESRD by spring 2014.

BLACKGOLD

The BlackGold segment focuses on the exploration, development and ultimately the production of in-situ oil sands located near Conklin, Alberta. BlackGold will use SAGD technology that includes horizontal well pairs and energy efficient thermal stimulation to liberate bitumen from the oil sands and minimize land disturbance. Phase 1 of the project is anticipated to produce 10,000 bbl/day with first steam expected in 2014. The scope of Phase 1 includes the drilling of 77 SAGD injector-producer well pairs over the life of Phase 1 and the construction of a central processing facility ("CPF"). Phase 2 of the project is targeted to expand the CPF and increase output to 30,000 bbl/d and was approved by the provincial regulators in 2013. BlackGold completed drilling of its initial 15 SAGD well pairs in 2012 and will perform the well completions in the second half of 2014 when the CPF is nearing completion to be ready to commence steam injection by the end of 2014. The overall project was approximately 92% completed by the end of 2013. Commissioning is targeted for the fourth quarter of 2014. Steam injection and thermal stimulation will typically take several months before material bitumen production begins. In 2014, BlackGold will focus on completing the CPF construction, preparing for commissioning and recruiting for the operations team. The construction of the CPF is conducted under an EPC contract. Expected total costs under the EPC contract have been revised upwards to approximately $650 million, due to increased costs as a result of labor shortages, inclement weather and a revised completion schedule. Under the EPC contract, a maximum of approximately $101 million of the EPC costs will be paid in equal installments, without interest, over 10 years commencing on the completion of the EPC work in 2014. See Item 3D "Risk Factors" for detail discussion on the uncertainties around the project development costs and timing.

BlackGold operates in the same business environment as Harvest's Upstream segment, please see Item 4B "Business Overview – Upstream" for details regarding pipelines, competitive conditions, EH&S and controls and regulations.

RESERVES AND OTHER OIL AND GAS INFORMATION

Harvest retained GLJ, a qualified Independent Reserves Evaluator, to evaluate and prepare reports on 100% of Harvest's crude oil and natural gas proved reserves and 100% of Harvest's crude oil and natural gas probable reserves as of December 31, 2013. All of Harvest's reserves were evaluated using the cost assumptions as at December 31, 2013 and the average first-day-of-the-month prices for the year ended December 31, 2013. All of Harvest's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan. See Exhibit 15.1 of this annual report for Independent Reserve Evaluator's report on evaluation methodology.

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.

Description of Harvest's Internal Controls Used in Reserve Estimation

The key technical person primarily responsible for overseeing the preparation of the year-end reserves evaluation is the Vice President ("VP"), Engineering, Doug Walker who has been with Harvest since August 2010. Mr. Walker has a degree in Chemical Engineering from the University of Calgary and is a registered Professional Engineer with APEGA. He has over 30 years of technical and business experience in operations, production, facilities, completions, drilling, reservoir engineering, business development and frontier projects. The VP, Engineering reports to the Deputy Chief Operating Officer ("Deputy COO"), Yongseok Kim, who is ultimately responsible for Harvest's reserve estimates.

The Independent Reserves Evaluator is selected and appointed by the Upstream Reserves, Safety and Environment Committee ("Reserves Committee"), with assistance from the VP, Engineering. Each evaluator's qualifications, industry experience and experience with Harvest's assets are reviewed to enable the Reserves Committee to approve the selection of Independent Reserves Evaluator.

For the year-end evaluation, Harvest supplied accounting data (including production, revenue and operating costs), land data and well files for any new drills to the Independent Reserves Evaluator to ensure they had accurate and adequate data for their review process. Harvest also conducted technical review meetings on major properties to highlight activities that were undertaken through the course of the year. The Independent Reserves Evaluator used Harvest and industry data and their expertise in each area with reserves evaluation and prepared draft reserves report for review with Harvest's exploitation engineers for each property. Reports were logged by Harvest's reserves coordinator to ensure accurate tracking and then forwarded to the appropriate exploitation engineers for detailed review. The exploitation engineers reviewed the draft reports to ensure all major developments in the previous year have been reflected in the report and to address any questions raised by the Independent Reserves Evaluator. This process continued until the final reports were received.

The VP, Engineering reviewed the final reports, ensuring that they were consistent with the previous reports and that appropriate changes (such as asset purchases or sales, revisions and drilling activities) have been made. After completing the review, the VP, Engineering presented the reports to the Deputy COO and the Reserves Committee together with a memorandum highlighting the significant changes from the prior year, including a reconciliation to gain an understanding of the additions, deletions and revisions made since the previous report. This memorandum was reviewed in detail by the VP, Engineering with the Reserves Committee to describe the key properties and major changes from the previous year. Significant differences between management and the Independent Reserves Evaluator, if any, were also discussed in this review.

A due diligence checklist was used by the Reserves Committee in reviewing the process to ensure comfort over the use of definitions, independence and qualifications. In addition, the Independent Reserves Evaluator attest to the Reserves Committee that the Reserves Report satisfied the NI 51-101 and SEC requirements, that the Independent Reserve Evaluator made their own independent assessments and that they were not pressured into any of their results or conclusions.

Net Reserves (Harvest's Share after Royalties)

The following table sets forth a summary of oil and natural gas reserves prepared by Harvest using constant pricing in accordance with the SEC's guidelines as of December 31, 2013. The year-end numbers represent estimates derived from the Reserves Report. The recovery and reserve estimates of Harvest's 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. Refer to Item 3D "Risk Factors" of this annual report for discussion on the uncertainties involved in estimating our reserves.

The crude oil, natural gas liquids and natural gas reserve estimates presented are based on the definitions provided in the SEC's regulations. A summary of these definitions are set forth below:

(a) **Net reserves** are the remaining reserves of Harvest, after deduction of estimated royalties and including royalty interests.

(b) **Proved reserves** are the estimated quantities of crude oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

(c) **Probable reserves** estimates are provided as optional disclosure under the SEC regulations. Probable reserves are those additional reserves that are less certain to be recovered than proved, however, together with proved are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

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

(a) **Developed** reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

(b) **Undeveloped** reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Estimates of total net proved crude oil or natural gas reserves are not filed with any U.S. federal authority or agency other than the SEC.

	Reserves					
	Light and Medium Oil		Heavy Oil		Bitumen	
	Gross (MMbbls)	Net (MMbbls)	Gross (MMbbls)	Net (MMbbls)	Gross (MMbbls)	Net (MMbbls)
Proved						
Developed producing	28.0	25.0	36.6	33.5	-	-
Developed non-producing	1.7	1.5	1.0	0.8	-	-
Undeveloped	1.7	1.5	7.1	5.8	95.6	88.1
	31.4	28.0	44.7	40.1	95.6	88.1
Probable						
Developed	8.0	7.1	12.4	11.3	-	-
Undeveloped	6.1	5.5	8.0	6.6	163.7	134.8
Total probable	14.1	12.6	20.4	17.9	163.7	134.8

	Reserves					
	Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
	Gross (Bcf)	Net (Bcf)	Gross (MMbbls)	Net (MMbbls)	Gross (MMboe)	Net (MMboe)
Proved						
Developed producing	179.4	163.4	8.3	6.0	102.8	91.7
Developed non-producing	11.8	10.8	0.6	0.5	5.2	4.5
Undeveloped	58.3	52.4	2.8	2.3	116.9	106.3
Total proved	249.5	226.6	11.7	8.8	224.9	202.5
Probable						
Developed	64.4	58.1	3.3	2.4	34.3	30.5
Undeveloped	62.3	56.1	6.3	4.8	194.4	161.2
Total probable	126.7	114.2	9.6	7.2	228.7	191.7

Undeveloped Reserves

As at December 31, 2013, Harvest has a total of 122.1 MMboe of gross reserves that are classified as proved non-producing, and of these non-producing reserves approximately 96% 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 economics and production information as at December 31, 2013. Substantially all of the undeveloped reserves are based on Harvest's then current 2014 budget and long range development plans for the major assets noted elsewhere in this document. Conventional Approximately 18% of Harvest's proved undeveloped reserves relate to the conventional oil and gas reserves. Of the conventional undeveloped reserves, approximately 23% are expected to be developed within the next two years. The remaining conventional undeveloped reserves are expected be developed within the next five years.

During 2013, Harvest drilled a gross total of 96 wells (84.1 net) with the vast majority of the development taking place in the following areas: Hay River, West Central Saskatchewan (heavy oil prospects), Red Earth, SE Saskatchewan and West Alberta. The bulk of the wells drilled had been previously assigned proved undeveloped (PUD) reserves and therefore these reserves were converted to proved developed. Total PUD reserves converted during 2013 were gross 4.5 MMboe which translates to a conversion rate of approximately 23% of the conventional oil and gas PUD reserves that existed at the end of 2012. In 2013, the cost incurred to develop proved undeveloped reserves was $106 million.

New PUD reserves were also assigned during the 2013 year-end evaluation recognizing the ongoing development of Harvest's properties. Total gross PUD reserves added for the 2013 year-end evaluation were 5.8 MMboe.

There are no material amounts of conventional oil and gas PUD reserves that have remained undeveloped for five years or more after their initial disclosure as proved undeveloped reserves.

BlackGold Bitumen

Approximately 82% of Harvest's proved undeveloped reserves are located on Harvest's BlackGold oil sands property. At the end of 2013, Harvest's BlackGold oil sands project had gross proved undeveloped bitumen reserves of 95.6 MMboe. The evaluation of these reserves anticipates they will be recovered using SAGD technologies over the next 25 years. As at December 31, 2013, 15 initial well pairs have been drilled. First steam is expected in late 2014 upon the completion of the CPF, followed by bitumen production a few months afterwards.

The BlackGold project requires the construction of steam generation, gathering systems and central processing facilities that service and support SAGD well pairs. The CPF is designed for 25 years of useful life (with up to approximately 35 to 40 years of useful life based on adequate maintenance) while the SAGD well pairs are designed to have individual useful lives of 7 – 13 years on a declining production basis. Therefore, to build a central facility that would process the entire field simultaneously would be neither economic nor environmentally efficient. Due to the high capital and operating costs associated with SAGD development and production, greater economic value and environmental efficiency are achieved by building a central facility with optimal capacity that provides for a set of SAGD well pairs to be drilled and produced over the life of the CPF. As the CPF has a long life relative to SAGD well pairs, in the early stages of a SAGD project, only a small portion of proved reserves will be developed as the number of well pairs drilled will be limited by the available steam and processing capacity. Once the initial 15 well pairs start producing in late 2014, the first 30 MMboe of proved undeveloped reserves are expected to convert to proved developed reserves. The remaining PUD reserves will convert to proved developed reserves as Harvest drill additional SAGD wells to offset declines from the initial 15 wells. The specific timing of the conversion of those remaining PUD reserves from undeveloped to developed after SAGD start-up will depend on when the well pair targeting those reserves is scheduled for drilling during the life of the CPF and steam generator. Development of the proved undeveloped reserves will take place in an orderly manner as additional well pairs are drilled to utilize the available steam and processing capacity when the SAGD reservoir of the initial well pairs is gradually depleted.

Harvest has delineated BlackGold bitumen reserves to a high degree of certainty through seismic data and core hole drilling, consistent with COGE Handbook guidelines. In most cases, proved reserves have been drilled to a density of 16 wells per section, which is in excess of the eight wells per section required for regulatory approval. In order to determine the economic cut-offs of undeveloped reserves, geological information is tested against existing production analogues that use SAGD process. Recognition of probable reserves requires sufficient drilling of stratigraphic wells to establish reservoir suitability for SAGD. Reserves will be classified as probable if the number of wells drilled falls between the stratigraphic well requirements for proved reserves and for probable reserves, or if the reserves are not located within an approved development plan area. The Independent Reserve Evaluator's standard for probable reserves is a minimum of four to eight stratigraphic wells per section, depending on the depositional environment. If reserves lie outside the approved development area, approval to include those reserves in the development plan area must be obtained before reserves can be classified as proved.

Production Volumes

	Production Volumes — 2013				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas *(mcf/d)*	111,313	104,269	114,066	111,954	115,050
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil	11,671	10,820	10,844	11,837	13,217
Heavy Oil	16,905	16,348	16,604	17,455	17,227
Natural Gas Liquids	5,345	4,607	5,324	5,510	5,953
Total Oil and Natural Gas Liquids	33,921	31,775	32,772	34,802	36,397
Total (*boe/d*)	52,473	49,154	51,783	53,461	55,571

	Production Volumes — 2012				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas *(mcf/d)*	122,385	119,554	120,315	125,680	124,045
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil	13,889	13,817	13,603	13,758	14,380
Heavy Oil	19,506	18,402	19,110	20,701	19,828
Natural Gas Liquids	5,535	6,084	4,920	5,468	5,668
Total Oil and Natural Gas Liquids	38,929	38,302	37,633	39,928	39,876
Total (*boe/d*)	59,327	58,228	57,686	60,874	60,550

	Production Volumes — 2011				
	Year	Q4	Q3	Q2	Q1
Natural Gas *(Mcf/d)*	112,360	121,547	124,259	111,291	91,888
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil	14,376	15,161	14,777	13,147	14,408
Heavy Oil	18,996	20,466	17,669	17,706	20,153
Natural Gas Liquids	5,062	5,440	5,392	5,937	3,455
Total Oil and Natural Gas Liquids	38,434	41,067	37,838	36,790	38,016
Total (*boe/d*)	57,161	61,324	58,548	55,338	53,331

Per-Unit Results

	Per-Unit Results — 2013				
	Year	Q4	Q3	Q2	Q1
Natural Gas ($/boe)					
Average sales price[(1)]	20.76	23.16	16.32	22.98	20.76
Royalties	1.22	1.06	0.86	1.88	1.10
Operating expenses	11.17	12.32	10.86	10.84	10.84
Crude Oil — Light and Medium ($/bbl)					
Average sales price	85.38	79.67	96.75	85.90	80.14
Royalties	13.42	14.77	16.24	12.44	11.26
Operating expenses	25.40	23.81	27.46	26.27	25.05
Crude Oil — Heavy ($/bbl)					
Average sales price[(1)]	74.37	68.03	88.47	76.55	64.38
Royalties	11.81	11.77	14.21	12.65	8.74
Operating expenses	21.66	21.81	20.88	20.97	23.16
Crude Oil — Total ($/bbl)					
Average sales price[(1)]	78.86	72.67	91.74	80.33	71.22
Royalties	12.47	12.96	15.01	12.57	9.83
Operating expenses	23.19	22.60	23.48	23.11	23.97
Natural Gas Liquids ($/bbl)					
Average sales price	57.44	58.97	57.20	53.48	60.16
Royalties	7.74	8.02	5.51	9.77	6.91
Operating expenses	13.84	14.39	13.07	13.76	12.88
Total ($/boe)					
Average sales price[(1)]	56.58	54.01	60.62	58.22	53.43
Royalties	8.04	8.29	8.84	8.55	6.54
Operating expenses	18.05	18.20	17.78	17.85	18.32

	Per-Unit Results — 2012				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas ($/boe)					
Average sales price(1)	15.50	20.65	15.09	12.68	13.75
Royalties	0.99	1.07	0.63	0.47	1.74
Operating expenses	11.68	9.34	12.52	11.98	12.89
Crude Oil — Light and Medium ($/bbl)					
Average sales price(1)	80.17	76.42	78.72	78.68	86.62
Royalties	11.36	10.17	11.28	12.80	13.05
Operating expenses	21.97	18.14	25.71	23.74	24.26
Crude Oil — Heavy ($/bbl)					
Average sales price	71.35	67.66	69.57	69.33	78.64
Royalties	11.93	10.18	11.98	11.43	14.07
Operating expenses	19.16	19.06	19.62	17.20	20.86
Crude Oil — Total ($/bbl)					
Average sales price(1)	75.01	71.42	70.76	70.55	81.99
Royalties	11.69	10.17	11.31	11.57	13.64
Operating expenses	20.33	18.67	21.30	19.05	22.29
Natural Gas Liquids ($/bbl)					
Average sales price	56.54	53.06	53.01	56.77	63.20
Royalties	7.04	6.36	3.08	3.48	14.69
Operating expenses	11.52	8.68	12.97	11.98	12.69
Total ($/boe)					
Average sales price(1)	53.60	52.82	52.02	51.42	58.07
Royalties	7.58	6.66	6.92	7.00	9.69
Operating expenses	16.54	14.45	17.55	15.98	18.14

	Per-Unit Results — 2011				
	Year	Q4	Q3	Q2	Q1
Natural Gas ($/boe)					
Average sales price	22.96	20.51	23.79	24.71	22.98
Royalties	2.05	2.22	1.76	3.76	0.12
Operating expenses	11.66	12.01	10.99	11.27	12.57
Crude Oil — Light and Medium ($/bbl)					
Average sales price(1)	88.37	92.01	84.49	96.54	81.00
Royalties	13.72	14.69	15.95	13.80	10.29
Operating expenses	22.28	22.85	21.90	23.68	20.80
Crude Oil — Heavy ($/bbl)					
Average sales price	76.07	83.40	68.25	82.96	69.34
Royalties	12.07	12.69	10.24	14.13	11.22
Operating expenses	19.41	19.20	19.16	17.84	21.22
Crude Oil — Total ($/bbl)					
Average sales price(1)	81.37	87.06	75.65	88.74	74.20
Royalties	12.78	13.54	12.84	13.99	10.83
Operating expenses	20.65	20.76	20.41	20.33	21.05
Natural Gas Liquids ($/bbl)					
Average sales price	67.92	70.14	67.51	79.87	69.32
Royalties	13.94	15.02	10.69	20.24	6.43
Operating expenses	10.44	12.01	12.60	11.51	2.60
Total ($/boe)					
Average sales price(1)	62.13	64.61	57.85	66.73	59.19
Royalties	9.37	9.93	8.72	11.23	7.47
Operating expenses	16.80	17.09	16.36	16.35	17.42

(1) Before gains or losses on commodity derivatives.

Drilling Activity

The following tables summarize Harvest's gross and net interest in wells drilled for the periods indicated.

	2013			
	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil Wells	2.0	2.0	65.0	62.7
Gas Wells	2.0	1.5	15.0	5.9
Service Wells	-	-	10.0	10.0
Dry Holes	1.0	1.0	1.0	1.0
Total Wells	5.0	4.5	91.0	79.6

	2012			
	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil Wells	6.0	4.4	105.0	95.6
Gas Wells	2.0	1.8	7.0	3.3
Service Wells	-	-	25.0	24.8
Dry Holes	-	-	1.0	1.0
Total Wells	8.0	6.2	138.0	124.7

	2011			
	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil Wells	15.0	14.0	163.0	145.0
Gas Wells	1.0	1.0	37.0	20.8
Service Wells	3.0	3.0	25.0	25.0
Dry Holes	7.0	5.5	-	-
Total Wells	26.0	23.5	225.0	190.8

Present Activities

Conventional

At December 31, 2013, Harvest was in the process of drilling or participating in a gross total of 7 development wells (4.6 net). These wells were located in the Red Earth, Deep Basin, Hay and West Central Alberta areas.

In addition to our oil and liquids-rich gas focused drilling program, Harvest is also continuing with its ongoing enhanced oil recovery projects in the large oil reservoirs at Hay River, Wainwright and Suffield.

Oil Sands

As of the end of 2013 Harvest had previously drilled 15 SAGD well pairs form the initial drilling development of the Phase 1 (10,000 bpd) of BlackGold oil sands project (well completions will be performed in the second half of 2014) and was focused on the construction of the CPF. Procurement and construction of the facilities for the BlackGold oil sands project were ongoing at year end. Site construction is expected to continue throughout 2014 with start-up scheduled for late 2014.

Location of Wells

The following table summarizes Harvest's interests in producing wells and wells capable of producing as at December 31, 2013.

	Gas		Oil		Total(1)(2)	
	Gross	Net	Gross	Net	Gross	Net
Alberta	2,550	856	4,172	3.136	6,722	3,992
British Columbia	160	59	697	463	857	522
Saskatchewan	59	45	1,026	884	1,085	929
Total	2,769	960	5,895	4,483	8,664	5,443

(1) Harvest has varying royalty interests in 858 natural gas wells and 402 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 796 gross natural gas wells and 944 gross crude oil wells.

Developed and Undeveloped Acreage

The following table summarizes Harvest's developed, undeveloped and total landholdings as at December 31, 2013.

	Developed(1)		Undeveloped(2)		Total	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
Alberta	1,095	606	697	506	1,792	1,112
British Colombia	139	78	232	139	371	217
Saskatchewan	66	61	47	38	113	99
Total	1,300	745	976	683	2,276	1,428

The following table summarizes Harvest's developed and undeveloped land holdings, expiring within one year from December 31, 2013.

	Developed(1)		Undeveloped(2)		Total	
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	20	14	48	44	68	58
British Colombia			23	17	23	17
Saskatchewan	2	2	17	9	19	11
Total	22	16	88	70	110	86

(1) Developed acreage is acreage assignable to productive wells; productive wells include producing wells and wells mechanically capable of producing.

(2) Undeveloped acreage encompasses those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves. Users of this information should not confuse undeveloped acreage with undrilled acreage held by production under the terms of the lease.

Harvest’s lease holdings comprise a large portfolio of leases in western Canada (with no single lease accounting for material acreage). There are a wide range of expiry dates for Harvest’s leases with no material number of leases or material amount of acreage holdings due to expire at a particular date. Harvest conducts ongoing development activities to retain land that would otherwise expire. As a result of these activities, the actual land holdings that will expire within one year may be less than indicated above.

Delivery Commitments

Harvest does not have any material long-term delivery commitments. Commitments relating to transportation and processing agreements have been disclosed under Item 5F “Tabular Disclosure of Contractual Obligations”.

DOWNSTREAM

Harvest’s Downstream business, operating under the name North Atlantic Refining Limited, is comprised of a medium gravity sour crude oil hydrocracking refinery with an 115,000 barrels per stream day nameplate capacity and a petroleum marketing business (the "Marketing Division") that is composed of five businesses. Downstream operations are predominantly located in the Province of Newfoundland and Labrador.

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. The prices for crude oil and refined products can fluctuate differently. In addition, the timing of the relative movement of the prices rarely matches. Feedstock are sourced and priced weeks before manufacturing and selling the refined products. Price level changes during the period between sourcing the feedstock and selling the refined products could have a significant impact to the refining business. As such, 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.

Due to logistics constraints and uneconomic transportation costs, the Refinery does not process crude oil produced by the Upstream. Downstream purchases all of the crude oil it processes from third parties. Downstream operates in similar industry conditions and competitive conditions as other independent refiners. As most refinery operating costs are relatively fixed, the goal of independent refiners is to maximize the yield of high value refined products and to minimize crude oil and other 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.

PRODUCTS AND MARKETS

Refining Business

An oil refinery is a manufacturing facility that uses crude oil and other feedstocks as raw materials 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: separating different types of hydrocarbons in crude oil, converting the separated hydrocarbons into more desirable or higher value products or chemically treating 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.

The Refinery produces ultra-low sulphur gasoline and diesel, jet fuel, furnace oil, and high sulphur fuel oil ("HSFO"). During 2013, approximately 10%-20% (2012 and 2011 – 10%-15%) of North Atlantic's refined products are sold in the Province of Newfoundland and Labrador while approximately 80%-90% (2012 – 85%-90%; 2011 – 70%-85%) is export cargos sold to MEC under the SOA (2011). Such cargos are shipped by MEC to U.S. east coast markets such as Boston or New York City and are also shipped to Europe, or farther abroad, when economics justify the increased shipping charge. During 2011, North Atlantic sold the majority of its distillates, gasoline products and HSFO to Vitol pursuant to the SOA and to MEC pursuant to the SOA (2011), with the remaining products sold in Newfoundland through the petroleum marketing division. Please refer to Item 10C "Material Contracts" for further information regarding the SOA (2011). North Atlantic's business and operating results are dependent on the SOA (2011) and the SOA partner, further discussion can be found at Item 3D "Risk Factors" of this annual report.

The following table shows the Refinery's sales by product for the years ended December 31:

($ millions)		**2013**		**2012**		**2011**
Gasoline products	$	1,446.0	$	1,529.2	$	1,055.1
Distillates		1,833.2		2,083.7		1,386.0
High sulphur fuel oil		759.3		899.8		556.3
Other[1]		249.4		116.0		135.1
Total sales	$	4,287.9	$	4,628.7	$	3,132.5

[1] Includes sales of vacuum gas oil and hydrocracker bottoms.

The following table provides the total amount of Downstream's export sales for the years ended December 31:

		2013		**2012**		**2011**
Total export sales (*$ millions*) [1]	$	3,420.0	$	3,820.3	$	2,349.5
Export sales as a percentage of total Downstream sales		80%		80%		71%

(1) Export sales in 2013 consisted of approximately 61% to the U.S. market and 39% to the European market (2012 – 60% to the U.S. market, 40% to the European market). Export sales for 2011 were primarily to the U.S. market with only immaterial amount exported to Europe.

FEEDSTOCK

The Refinery's crude oil and other feedstocks are waterborne cargos originating from outside of Canada. Typically, there are approximately 20 days of crude oil feedstock in tankage at the Refinery to mitigate the effects of any supply disruptions. A discussion on the volatility of feedstock prices is included in Item 3D "Risk Factors" of this annual report. During the last three years, the region of origin of the feedstock has been as follows:

Region	**2013**	**2012**	**2011**
	(Mbbls)	(Mbbls)	(Mbbls)
Middle East	24,517	33,571	20,938
South American	499	480	-
Russian	1,445	1,449	1,460
North American	5,462	-	-
Other	3,876	2,328	2,438
Total Feedstock	**35,799**	**37,828**	**24,836**

TRANSPORTATION

The Refinery has a transportation advantage as a result of its ice-free, deep water docking facility and it has approximately seven million barrels of tankage, including six 575,000 barrel crude tanks. These enable the receipt of crude oil transported on very large crude carriers which typically result in lower per barrel transportation charges. North Atlantic's dock facilities are used for off-loading refinery feedstocks and for loading refined products. The dock facilities handle approximately 220 vessels each year, with North Atlantic owning and operating two tugboats to assist with berthing and un-berthing tankers.

GROSS MARGIN

Refining gross margin is a function of the sales value of the refined products produced and the cost of crude oil and other feedstocks purchased as well as the yield of refined products from various feedstocks. North Atlantic continuously evaluates the market and relative refinery values of several different crude oils and vacuum gas oils (“VGO”) to determine the optimal feedstock mix. North Atlantic also analyzes the refining gross margin for its sales revenue relative to refined product benchmark prices and the Brent benchmark prices. With respect to feedstock costs, North Atlantic analyzes price discounts relative to the Brent benchmark prices and segregate crude oil sources by region of origin for reporting. See the Downstream risk factors included in Item 3D of this annual report for a discussion on the volatility of refining margins due to fluctuations in market prices for crude oil feedstocks and refined products.

Marketing Division

North Atlantic’s marketing division (the "Marketing Division") is headquartered in St. John's, Newfoundland and is composed of five businesses: retail gasoline (with 52 retail stations, including 40 locations branded as "North Atlantic", 7 locations branded as "Home Town" and 5 unbranded locations, and 3 commercial cardlock locations), retail heating fuels, commercial, wholesale and bunkers. Most retail locations include a convenience store which is independently operated, except for 10 branded locations, which are fully operated by North Atlantic and 4 franchise locations which are referred to as “Orangestore.” In 2013, the volume of gasoline sold at these retail locations represented a market share of approximately 28% of the Newfoundland market. The 2013 daily sales volume of North Atlantic’s marketing division averaged over 13,000 barrels of refined products, including gasoline, furnace oil, heating oil, propane, jet fuel, and bunker fuel. Customers include both wholesalers and end-users. The major competitors in the Newfoundland market are Irving Oil, Imperial Oil and Ultramar.

COMPETITIVE CONDITIONS, SEASONALITY, AND TRENDS

Competitive conditions and trends are described under Harvest’s risk factors in Item 3D of this annual report. The refinery business is cyclical and volatile. Cyclicality occurs when periods of tight supply, resulting in increased prices and profit margins, are followed by periods of capacity expansion, resulting in oversupply and declining prices and profit margins. Volatility occurs as a result of changes in supply and demand for products, changes in energy prices, and changes in various other economic conditions around the world. Seasonality can impact product margins as customer demand levels increase or decrease as a result of the change in seasons. The Refinery operational cycle is tied to its major maintenance schedule where generally a partial plant outage is planned for every two years and a full plant outage is planned for every six years.

ENVIRONMENT, HEALTH AND SAFETY POLICIES AND PRACTICES

Downstream’s EH&S policy is to comply with, or exceed, regulations relevant to the industry and to fully cooperate with the regulatory bodies. Downstream operations have an active and comprehensive Integrated Management System to promote the integration of safety, health and environmental awareness into the Refinery and related businesses. The key components of the system are core elements applicable to most large industries, and include safety, process safety, environmental and health. It also includes a Continuous Improvement Management System that guides the development and improvement of these elements. The system has assisted in reducing the refinery injury rate. In 2013 the refinery achieved a Lost Time Injury Frequency of 0.19 compared to an Industry Achieved of 0.20, as published by Bureau of Labour Statistics 2012.

Downstream has been issued a new Certificate of Approval from the Provincial Government’s Department of Environment and as well, has signed off on a new Compliance Agreement as part of the certificate renewal. As a consequence of this new agreement, certain atmospheric storage tanks are required to recertify within a specified time period and, as such, these cost comprise a significant portion of Downstream’s forecasted capital expenditure for the next three years. The timing of the recertification of each tank will be completed so as not to interrupt the operations of the refinery resulting in minimum additional operational costs.

CONTROLS AND REGULATIONS

The petroleum refining industry is subject to extensive controls and regulations governing its operations (including marine transportation, refined product specifications, emissions and marketing) 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 the 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 Harvest is unable to predict what additional legislation or amendments may be enacted.

Pricing (Marketing Division)

Since 2001, 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 Products Act (Newfoundland), administered by the Public Utilities Board of Newfoundland and Labrador. 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 are adjusted weekly based on the New York Harbour benchmark price for these products.

ENVIRONMENTAL REGULATION

The oil and natural gas industry is 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. Environmental assessments and approvals are required before initiating most new larger projects or changes to existing operations. In addition, such legislation requires that well and facility sites are abandoned and reclaimed to the satisfaction of provincial authorities, and in most instances, any liability associated with the sites remains with the company. 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. It is expected that future changes to environmental regulations, including air pollutants and GHG, water usage and land use planning, will impose further requirements on companies operating in the energy industry. As such, Harvest expects that its future capital and operating costs for environmental protection and controls will likely increase. Harvest cannot predict the changes that could be made to environmental regulations and the resulting financial impact. Given any future regulations will be imposed to the industry as a whole, Harvest believes that any cost increases relating to environmental protection or compliance will not materially impact Harvest’s competitive position. Harvest has assessed the impact from the existing environmental laws and regulations of jurisdictions in which Harvest operates, and provides a summary on the significant ones below.

Climate Change

Federal

In December 2011, the Canadian Federal government announced that it would not commit to the requirements set by the Kyoto Protocol. Instead the government has endorsed the Durban Platform, a negotiation framework for a new international climate change agreement to include all emitters, for completion by 2015 and implementation by 2020. Canada also remains committed to reduce its GHG emissions by 17% below 2005 levels by 2020 under the Copenhagen Accord.

In March 2008, the federal government released an updated regulatory framework for air emissions entitled Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions. This framework proposes mandatory emission intensity reduction obligations on a sector by sector basis. To date, only transportation and coal-fired electricity sector regulations have been developed. In line with the United States, Canada has adopted a renewable fuels standard mandating an average of 5% renewable content in gasoline and 2% renewable content for diesel and heating oil. It is uncertain as to when the oil and gas industry sector targets will be developed. Harvest will continue to monitor the Federal GHG regulatory changes and will be able to determine if there is any financial impact once guidelines are established. On an ongoing basis, Harvest continues to undertake projects that reduce emission of GHGs such as evaluating the injection of carbon dioxide into oil reservoirs and the further capture of fugitive emissions in our field operations as part of our annual capital program.

Alberta

In 2007, the Government of Alberta introduced the Climate Change and Emissions Management Amendment Act which provides a framework for managing GHG emissions by reducing specified gas emissions to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020. The regulations include the Specified Gas Emitter Regulations (“SGER’) and the Specified Gas Reporting Regulation (“SGRR”) which imposes GHG limits and emission reporting requirements. The SGER applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year and requires emission intensity (i.e. quantity of GHG emissions per unit of production) reductions from intensity baselines. The SGRR imposes GHG emission reporting requirements on facilities that have GHG emissions of 50,000 tonnes or more in a year. Harvest currently does not have any facilities exceeding these thresholds. However, with the commissioning of the BlackGold SAGD facility in late 2014, it is expected this facility will trigger the requirements of both the SGRR and the SGER. For new facilities, the required reduction from its baseline is phased in by annual 2% increments beginning in the fourth year of commercial operation until an annual 12% reduction requirement is reached, and once reached such 12% reduction must be maintained over time. Currently, there are three methods for companies to comply with the emission intensity reduction requirements: 1) improve emission intensity at the facility; 2) purchase emission offset credits in the open market; and/or 3) purchase fund credits by contributing to the Alberta Climate Change and Emission Management Fund run by the Alberta government. Historically the cost for 1 tonne of CO_2e (carbon dioxide equivalent) is set at $15/tonne. The SGER will expire in September 2014. The Government of Alberta has indicated that the regulation will likely be renewed and is currently considering revisions to the regulation. As the BlackGold SAGD facility will not be operational until late 2014, Harvest will continue to monitor for changes to the regulation and will assess the compliance costs accordingly.

British Columbia

Under the Greenhouse Gas Reduction Targets Act, the Province of British Columbia is legislated to reduce its GHG emissions to 33% below 2007 levels by 2020 and 80% by 2050. Interim reduction targets of 6% by 2012 and 18% by 2016 will help guide and measure progress.

A carbon tax was implemented on the purchase or use of fossil fuels within the Province of British Columbia, starting at $10/ton on July 1, 2008 and rising by $5 per year to $30/ton in 2012. Fuel sellers are required to pay a security equal to the tax payable on the final sale to end purchasers and end purchasers are required to pay the tax. Fuel sellers collect carbon tax at the time fuel is sold at retail to the end purchaser. Carbon capture and storage is required for all new coal-fired electricity generation facilities and a 0.4% levy tax has been implemented at the consumer level on electricity, natural gas, grid propane and heating oil that goes towards establishing the Innovative Clean Energy Fund.

In 2008, the Province of British Columbia introduced the Greenhouse Gas Reduction (Cap and Trade) Act (“Cap and Trade”) which authorizes hard caps on greenhouse gas emissions. Any British Columbia facilities emitting 10,000 tonnes or more of carbon dioxide equivalent emissions must report its GHG emission annually and those reporting operations with emissions of 25,000 tonnes or greater are required to have the emissions reports verified by a third party.

Harvest currently has a facility in British Columbia that exceeds the threshold for reporting. In 2013, the cost to Harvest to comply with the Cap and Trade Act was approximately $75,000 which included the GHG inventory and third party verification as required by the regulation. It is expected this will be an annual cost to comply with this regulation, however, there may be additional costs required to meet future reduction targets which have not been yet set by the Province of British Columbia. Saskatchewan The Management and Reduction of Greenhouse Gases Act received Royal Asset in Saskatchewan in May 2010, however is still waiting final proclamation. The legislation will establish a provincial plan for reducing GHG emissions to meet provincial targets. The Province has also indicated that it intends to enter into an equivalency agreement with the federal government to achieve equivalent environmental outcomes with respect to GHG compliance. Harvest will continue to monitor the GHG regulatory requirements in Saskatchewan and meet all regulatory compliance expectations.

Newfoundland

The Federal Renewable Fuel Regulations were published in the Canada Gazette, April 10, 2010. At that time an exemption was provided for the addition of ethanol to gasoline sold in Newfoundland and Labrador and on June 20, 2011 a further exemption was provided for the requirements for renewable content in diesel fuel and heating distillate oil sold in Newfoundland and Labrador. These exemptions, while in place, benefit our Downstream operations by providing relief from the Federal Renewable Fuel Regulations.

In 2011, the Government of Newfoundland and Labrador published its Climate Change Action Plan. The Province has not established any regulations pertaining to the Climate Change Action Plan but has indicated its intention to introduce GHG Regulations and seek equivalency agreement with the Federal Government; hence, Harvest is unable to determine the impact to the Refinery business.

Land Use

In response to Alberta's growth over the past 10 years, the government commenced a comprehensive initiative to develop a new land-use system for the province. The government released the Land-use Framework for Alberta in December 2008. This Land-use Framework called for the development of seven regional plans which will become the governing land-use policy for each region. In August 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("LARP"). The LARP outlines management frameworks for protecting, monitoring, evaluating and reporting air, surface water and groundwater quality by setting strict environmental limits. In addition, conservation areas will increase by approximately 16% to a total of 22% of the region's land base. The proposed new conservation areas do not appear to affect Harvest. Harvest will comply with all regulatory requirements associated with the LARP framework in which it operates and meet the requirements outlined in the LARP- Related Application requirements set out recently by the AER.

The second plan now underway is the South Saskatchewan Regional Plan ("SSRP") which is currently in draft stage but the government is in final stages of collecting feedback by February 28, 2014. The regional plan will create new conservation areas, establish environmental limits, protect water supply and provide clarity about land use and access. The final SSRP framework is set to be released in April 2014. Based on a preliminary assessment, the proposed new conservation area appears to have minimal to no effect on Harvest.

Hydraulic Fracturing

In early 2012, the Canadian Association of Petroleum Producers ("CAPP") announced new Canada-wide hydraulic fracturing operating practices. Hydraulic fracturing is the process of pumping a fluid or gas under pressure down a well which causes the surrounding rock to crack or fracture. The proliferation of fracturing in recent years has raised concerns about environmental impact including water quality and supply. Harvest has adopted the practices which include disclosure of fracture fluid additives to the public, developing risk assessment and management plans, conducting baseline groundwater testing, ensuring proper wellbore construction prior to fracturing, water use management planning and safe fluid transport, handling, storage and disposal.

In May 2013, the AER released Directive 83 – Hydraulic Fracturing Notification Submission Procedure effective August 21, 2013, which sets out the requirements for managing subsurface integrity associated with hydraulic fracturing operations. The Directive will also require all fracturing operations to submit a Hydraulic Fracturing Notification Submission Form to the AER for each well license or well pad.

Harvest uses hydraulic fracturing in some of its well completion practices. This completion technique is a well-established procedure, with over 2 million such stimulations performed globally to date and when conducted using current technology and best practices pose insignificant environmental risk. These stimulations are typically performed on reservoirs several thousands of feet deep. Ground water aquifers are, in turn, tens to hundreds of feet deep and separated from the fractured zones by thousands of feet of overburden and one or more layers of steel pipe cemented in place within the wellbore itself.

Fracture stimulations are designed to treat only the hydrocarbon bearing formation. During the operation, pressures and injection rates are monitored live on site, and in the service company's headquarters and Harvest's offices. Injection rates and pressures are adjusted in real time to keep the fracturing within design parameters based on the observed rate and pressure information as the fracture stimulation is underway.

Harvest only selects contractors to conduct its field operations which adhere to Industry best practices. Those practices include engineered and documented stimulation design, live monitoring and control of rates, pressures and proppant concentrations throughout the operation to keep the operation within design parameters, isolation of any or all groundwater or aquifers through cemented casing and a large vertical separation between the aquifers and the zones being stimulated, and safe fluid transport, handling, storage and disposal. The produced frac fluids are recovered on surface and either reused in subsequent stimulations on other wells or disposed of in licensed disposal facilities.

Harvest is not aware of any negative or adverse consequences to date from any of Harvest's historic fracture stimulation operations.

Harvest plans on drilling about 90 to 95 gross wells in 2014, of which 15 to 20 will be stimulated using hydraulic fractures. Approximately $30 to $40 million of Harvest's 2014 capital budget will be allocated to fracture stimulation operations.

Species at Risk Act

In April 2012, Environment Canada ("EC") announced that it will be adding 18 species to the Species at Risk Act ("SARA") due to increased pressure and threats that put these species at risk of extirpation or extinction. It is expected the impacts of the addition of these species to Harvest's operation to be low given the relatively small portion of species range covered in the area of application. Harvest will continue to assess and monitor wildlife impacts for existing and new operations and ensure it meets the setback requirements as outlined in SARA for each individual species.

As of November 18, 2013, EC introduced an Emergency Protection Order for the Greater Sage-Grouse. The order targets crown lands and federally owned lands but not private lands. A recent review shows no Harvest areas of interest fall within the designated areas.

Water Supply

In October 2012, the Saskatchewan government released their 25 Year Saskatchewan Water Security Plan. The intent of the plan is to ensure the sustainability and quality of Saskatchewan surface and groundwater supplies while protecting drinking water supplies from the source to the tap. The plan outlines seven goals: Sustainable Supplies, Drinking Water Safety, Protection of Water Resources, Safe and Sustainable Dams, Flood and Drought Damage Reduction, Adequate Data, Information and Knowledge and Effective Governance and Engagement. Alberta government also has the Water for Life initiative since 2003 which goals are to ensure safe and secure drinking water, healthy aquatic ecosystems and reliable quality water supplies for a sustainable economy. However, no regulations pertaining to the water usage have been established under these initiatives yet. Harvest will continue to monitor these plans as new acts and regulations are developed as a result of these overall plans.

Oil Sands Monitoring Plan

On February 3, 2012, the Government of Alberta and the Government of Canada released the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring (the "Monitoring Plan"). The Monitoring Plan is designed to provide an improved understanding of the cumulative environmental impact of oil sands development and will increase air, water, land and biodiversity monitoring in the oil sands region. The Monitoring Plan is expected to be phased in over a three-year period and is expected to be fully implemented in 2015. The total cost to the industry is estimated to be approximately $50 million per year. Upon the commissioning of BlackGold, it is expected that Harvest will be contributing to the funding of the Monitoring Plan.

Abandonment and Reclamation

In Alberta, the AER maintains a Licensee Liability Rating ("LLR") program to ensure abandonment and reclamation cost of oil and gas wells, facilities and pipelines are covered by the industry. The AER requires oil and gas operators to post financial security deposits to cover the abandonment and reclamation costs in the event a licensee defaults on its obligations. In March 2013, the AER updated the LLR program to address concerns that the previous LLR program significantly underestimated abandonment and reclamation liabilities of AER licensees. Effective May 1, 2013, the AER increased the security deposit and will require 248 licensees to post financial security of $297 million over a three year period. Harvest does not expect to be subject to a security deposit.

On June 19, 2007, a new orphan oil and gas well and facility program was introduced in Saskatchewan, solely funded by oil and gas companies to cover the cost of cleaning up abandoned wells and facilities where the owner cannot be located or has gone out of business. The program is composed of a security deposit, based upon a formula considering assets of the well and the facility licensee against the estimated cost of decommissioning the well and facility once it is no longer producing, and an annual levy assessed to each licensee.

Renewable Fuel Standards

Under the Energy Independence and Security Act of 2007, the United States Environmental Protection Agency issued the Renewable Fuel Standard program that mandates the total volume of renewable transportation fuel sold or introduced in the U.S. and require refiners to blend renewable fuels such as ethanol and advanced biofuels with their gasoline. The mandate requires the volume of renewable fuels blended into finished petroleum products to increase over time until 2022. To the extent refineries do not blend renewable fuels into their finished products, they must purchase credits, referred to as RINs, in the open market. A RIN is a number assigned to each gallon of renewable fuel produced or imported into the United States.

Harvest's realized prices from RBOB gasoline and ultra-low sulphur diesel ("ULSD") sold in the U.S. market includes RINs costs to meet regulatory requirements. During 2013, the cost of RINs increased substantially over the previous year averaging approximately US$2.50/bbl for RBOB gasoline and US$3.00/bbl for ultra-low sulphur products as compared to US$0.75/bbl and US$0.55/bbl for RBOB and ULSD respectively in 2012.

C. Organizational Structure

Harvest is a wholly-owned subsidiary of KNOC. Each of the subsidiary entities identified below is a direct or indirect wholly-owned subsidiary of Harvest Operations.

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. Breeze Trust No. 1 is wholly owned by Harvest Operations Corp. 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. Breeze Trust No. 1 has a 99% interest in each of the Breeze Resources Partnership and the Hay River Partnership.

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. Breeze Trust No. 2 is wholly-owned by Harvest Operations Corp. and its assets consist of a 1% interest in each of the Breeze Resources Partnership and the Hay River Partnership.

Breeze Resources Partnership, a general partnership

Breeze Resources Partnership (indirectly wholly owned by the Harvest Operations) is a general partnership formed on June 30, 2004 under the laws of the Province of Alberta. Breeze Resources Partnership was acquired in September 2004. Its assets consist of the tangible portion of direct ownership interest in petroleum and natural gas properties located in east central Alberta and southern Alberta.

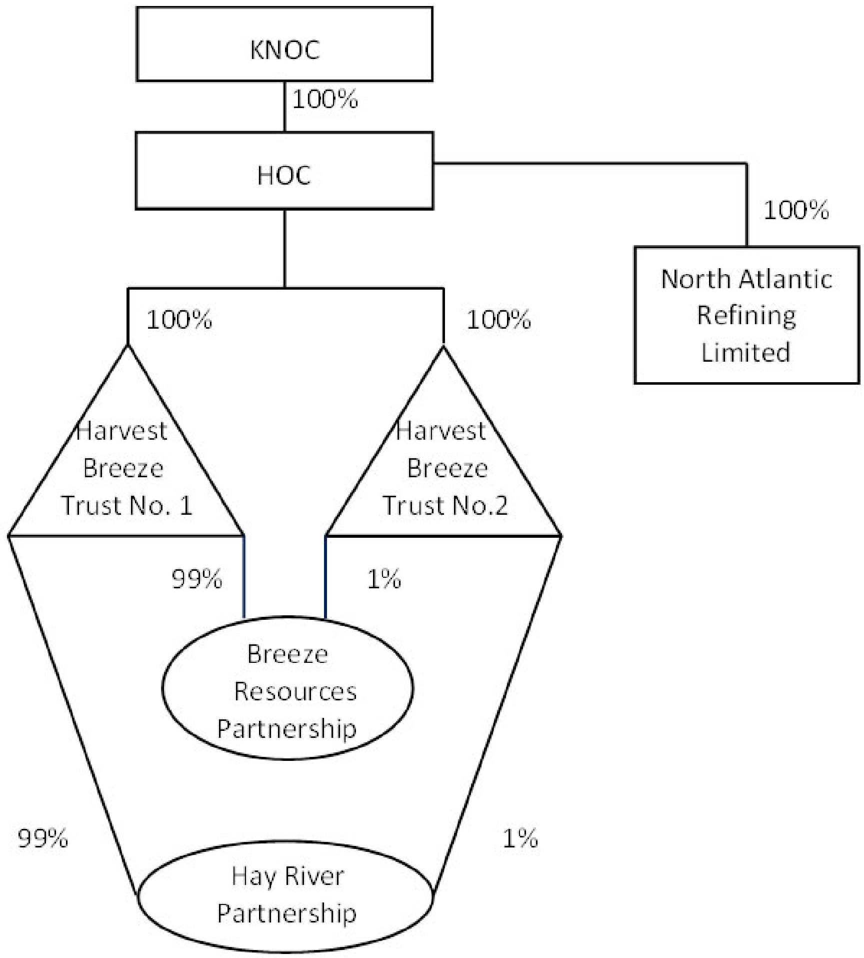
Hay River Partnership, a general partnership

Hay River Partnership (indirectly wholly-owned by Harvest Operations) is a general partnership formed on December 20, 2004 under the laws of the Province of Alberta. Hay River Partnership was acquired in August 2005. Its assets consist of the tangible portion of direct ownership interests in petroleum and natural gas properties located in northeastern British Columbia.

North Atlantic Refining Limited, a taxable Canadian corporation

North Atlantic Refining Limited was incorporated under the laws of the Province of Newfoundland and Labrador on November 17, 1986. North Atlantic is a wholly owned subsidiary of Harvest Operations, with assets consisting of the Refinery and related retail marketing assets. North Atlantic is responsible for providing the engineering, operations and administrative services related to downstream operations.

The corporate structure including significant subsidiaries is set forth below. Harvest's remaining subsidiaries and partnerships did not have assets or sales and operating revenues which, in the aggregate, exceeded 20 percent of the total consolidated assets or total consolidated sales and operating revenues of Harvest as at and for the year ended December 31, 2013:



D. Property, Plant and Equipment

UPSTREAM & BLACKGOLD

MATERIAL PROPERTIES

In general, the material 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. Harvest Operations is actively engaged in cost reduction, production and reserve replacement optimization efforts directed at reserves addition through extending the economic life of these producing properties beyond the limits used by the Independent Reserves Evaluator. 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.

2013 Historical Production by Material Property

Material Property	Light & Medium Crude Oil bbl/d	Heavy Oil bbl/d	Natural Gas mcf/d	NGLs bbl/d	Average Daily Production boe/d
Hay River	-	5,175	235	23	5,237
Red Earth	3,280	-	125	57	3,358
West Central Alberta	1,482	314	52,437	3,953	14,489
East Central Alberta	2,855	3,648	3,843	158	7,302
Deep Basin	64	-	36,679	907	7,084
Heavy Oil	-	6,258	1,133	24	6,470
Saskatchewan Light Oil	2,813	-	239	10	2,862
Other	1,177	1,510	16,622	213	5,671
TOTAL	11,671	16,905	111,313	5,345	52,473

Hay River

Hay River was acquired by Harvest on August 2, 2005 and is located approximately 125 miles north west of Grande Prairie in north-eastern British Columbia. In 2013, Hay River produced 5,237 boe/day of 24º API crude oil (including a trace – 23 barrels per day of condensate and a 235 mcf per day of solution gas) from the Bluesky formation located at a depth of approximately 350 metres. Natural gas produced from this formation, along with produced water, were re-injected for pressure support. Produced emulsion is processed at the 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 reasonably undertaken when the ground is frozen (typically between late November and mid-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 a 100% Working Interest in this operated property. In 2013, Harvest drilled 28 gross 100% Working Interest wells, including 16 horizontal producing wells, and 9 water injection wells and established new infrastructure with a total capital expenditure of $63 million.

Since 2007, Harvest has focused on increasing water injection into the producing Bluesky formation to improve overall pressure support, production and recovery of oil from the reservoir. The reinjection of produced water is now being augmented with additional make-up water from the Gething formation. A gas plant constructed in 2007 was commissioned in the spring of 2008 to eliminate flaring at the site and to manage production of associated gas. Connection of commercial power to the site was also completed in 2008 which allowed for optimization of the production in the field.

Red Earth

Red Earth is located 300 miles north west of Edmonton, Alberta. Production in 2013 from Red Earth averaged 3,358 boe/d (98% oil), with an average oil quality of 37° to 39° API from the Slave Point, Granite Wash and Gilwood Formations. Harvest followed through on its 2012 partnership with the Loon Lake First Nations for an option on up to 26 sections of land, by commencing drilling in Q3 2013.

In 2013, Harvest drilled 13 gross wells with total capital expenditures, including roads and pipelines, of $58 million. A majority of the drilling was made up of horizontal wells in the Slave Point Formation using multi-staged fractured completions.

West Central Alberta

West Central Alberta is comprised of properties west of Highway 2, south of Edmonton and north of Calgary. This is primarily a liquids-rich natural gas producing area for the Corporation with some oil production. Properties for this area were added through acquisition over the last several years with the most recent major acquisition being Hunt Oil Company of Canada, Inc.'s and Hunt Oil Alberta Inc.'s (collectively, "Hunt") assets in 2011. Production in 2013 for the region averaged 14,489 boe/d (60% gas).

Major fields in this area include Caroline (Beaverhill Lake liquids rich 50% H2S gas), Crossfield (Ellerslie oil and Basal Quartz gas), Markerville (Pekisko, Edmonton Sands, Cardium and Glauconite and Ellerslie) and Rimbey (Glauconite, Ostracod, Notikewin and Cardium). All new liquids-rich gas production and oil production are from stage stimulated horizontal wells except for a highly prolific vertical gas play in the Glauconite.

In 2013, Harvest participated in 13 gross wells (2 oil, 11 gas), 4.6 net wells for a total capital expenditure $18 million.

East Central Alberta

This area mainly encompasses legacy oil properties from the Saskatchewan / Alberta border to Alberta Highway 2 and between the cities of Edmonton and Calgary. Working interest in these properties is over 90%. In 2013, the average production was 7,302 boe/d (89% oil) and is primarily heavy and medium oil from 18º to 32º API. The Corporation’s largest group of legacy properties such as Wainwright, Bellshill, Provost and Bashaw are in the region. This area remains largely focussed on EOR projects both conventional and evolving as well as optimization of current wells and facilities. Harvest did no drilling in East Central Alberta in 2013.

Deep Basin

The Deep Basin was acquired from Hunt in early 2011 and has been an area of strong drilling results and reserves success. The Deep Basin is located to the south of the city of Grande Prairie in northwest Alberta.

Production in 2013 continued to grow, averaging 7,084 boe/d (86% gas). Legacy production is from vertical wells completed in multiple zones (Falher, Cardium, Cadotte, Cadomin, Bluesky, Dunvegan, and Gething) and comingled together. Drilling activities have been focused on drilling high rate 5 to 15 mmcf/d, stage-stimulated horizontal wells in the Falher formations (Falher C, F and G). In 2013, Harvest participated in 5 gross (3 net) wells and added to our land base and expanded our gathering system infrastructure for a net cost of $50 million.

Heavy Oil

Harvest has various working interests in this area, which is located near the town of Lloydminster on both the Alberta and Saskatchewan side of the border and down into Southern Alberta near the city of Medicine Hat. Major properties in this group include Suffield (Glauconite), Maidstone (Sparky and Waseca), Lloyd (Lloydminster), and Hayter (Dina/Cummings and Sparky).

Production is 12° to 15° API heavy crude oil from Cretaceous aged sandstone formations within the Mannville group. Production averaged 6,470 boe/d (97% oil) in 2013. Harvest drilled 23 gross wells in 2013 (17 in the Heavy Oil area and 6 in the Suffield area) with total net capital expenditures of $41 million. The majority of the wells drilled were horizontal in the Lloydminster formation or the Glauconite.

Production in each of these areas wells generally goes to central processing facilities with solution gas conservation and oil trucked to third party sales points, except for Hayter and Suffield which are pipeline connected. Future plans include downspacing pools with additional horizontal wells and assessing the potential impact of water injection for pressure maintenance and enhanced recovery.

This area also contains EOR potential. By increasing injection and using chemical enhancements such as polymers, Harvest believes the ultimate recovery of oil can be further increased. Pool optimization and EOR projects will target increased water injection into under-injected reservoirs that have not received adequate pressure maintenance as well as the expansion of the existing Suffield polymer flood to further enhance sweep efficiencies.

Saskatchewan Light Oil

This area includes Harvest’s assets in southeast Saskatchewan towards the Manitoba border. It used to include production near the City of Kindersley in western Saskatchewan, near the Alberta border. The Kindersley assets were sold in early 2013. The SE Saskatchewan properties are located approximately 110 miles southeast of Regina with production from the non-stage stimulated horizontal wells in Tilston and Souris Valley formations of Mississippian age. Both of these properties contain high netback light 34° to 39° API oil.

Production in 2013 was 2,862 boe/d (98% oil). In 2013, Harvest participated in 8 gross wells and the construction of an oil battery in our Manor oil development project with a total net capital expenditure of $20 million.

BlackGold

Harvest acquired a 100% Working Interest of BlackGold in 2010 from KNOC. The area is located in northeast Alberta near Conklin and is in close proximity to a number of major oil sands developments.

In 2013, detailed engineering, procurement and fabrication of several modules for the central processing facilities and well pads continued, with construction of the facilities the primary focus in 2013 as the project prepares for Phase 1 start-up in 2014. At December 31, 2013, Phase 1 of the project was 92% complete. Phase 1 will inject steam for several months and then begin oil production, with a targeted rate of 10,000 boe/d. Phase 2 of the project, which is targeted to increase production capacity to 30,000 bbl/d, received all required regulatory approvals in 2013.

BlackGold's capital program in 2013 was $444.5 million and was applied to the detailed engineering and equipment procurement and fabrication.

For further details regarding the BlackGold project, please refer to Item 4B "Business Overview". 2014 CAPITAL EXPENDITURE PLAN

Harvest's expected total capital spending on its oil and natural gas properties for 2014 is expected to be approximately $500 million. Harvest plans to fund future capital expenditures through borrowings from the Credit Facility, Related Party Loan from KNOC and cash from operating activities. For further discussion regarding Harvest's liquidity and capital resources, please refer to Item 5B. The primary areas of focus for Harvest's Upstream and BlackGold capital program during 2014 are the following:

- BlackGold – Expenditures of approximately $150 million to continue development of the central processing facility and completion of the 15 SAGD well pairs drilled in 2012 as Harvest gets ready for first steam in late 2014;
- Upstream – Expenditures of approximatedly $350 million, including:
  - Hay River – Drill 18 gross producing vertical and horizontal multi-leg horizontal oil wells and water injection wells (7 producers, 3 injectors, 2 water source wells and 6 stratigraphic test wells to set up future development);
  - Red Earth – Drill 6 gross light oil wells, primarily at Loon Lake;
  - West Central/Rimbey – Drill 8 gross wells targeting the Cardium oil/gas/NGL stage stimulated horizontal wells, Ellerslie light oil vertical wells and Glauconitic (liquids-rich natural gas) stage stimulated horizontal wells;
  - Heavy Oil – Drill 20 heavy gravity horizontal oil wells;
  - Deep Basin Area – Drill 9 gross Falher horizontal stage-fractured liquids-rich natural gas wells;
  - Cecil – Drill 6 Charlie Lake horizontal, unstimulated oil wells;
  - Southeast Saskatchewan Area – Drill 9 gross horizontal light oil wells into the Souris Valley and Tilston formations;
  - Suffield and Wainwright – Drill 6 wells and expand and continue to inject polymer into the two existing EOR floods; and
  - Various Areas
    - o Expenditures of approximately $10 million to exploration projects which includes drilling, seismic and land purchases;
    - o Expenditures of $20 million to optimize existing producing wells and facilities and $30 million to highgrade or replace existing production infrastructure; and
    - o Expenditures of $30 million for land and seismic to set up future development opportunities, $20 million to abandon existing wells, and $13 million to maintain or enhance EOR schemes and for corporate capital.

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 Reserves Report. These opportunities include:

- Implementation or optimization of enhanced water floods beyond the two polymer floods previously mentioned in selected pools such as Suffield, Hay River, Red Earth, Cecil 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;
- 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 3-D seismic;
- Numerous exploratory opportunities defined by seismic from which value might be extracted by sale, Farmout or joint venture;
- Management of dry gas portfolio to shut-in wells currently with low gas netbacks due to falling gas prices to preserve reserves to be produced at a time when gas prices improve; and
- Utilizing multistage fractured technology in horizontal wells to increase oil recovery from tight oil and gas formations at Red Earth (Slave Point Formation), Crossfield (Basal Quartz and Ellerslie Formations), Kindersley (Viking Formation), Deep Basin (Falher Formation) and Rimbey/West Central Area (Cardium, Glauconite, Viking, Ostracod, Notikewin, Wilrich Formations).

DOWNSTREAM

In the Downstream operations the only material asset is the Refinery. The Refinery is a 115,000 barrels per day medium sour crude oil hydrocracking refinery, located on the east coast of Canada in the province of Newfoundland, and is capable of processing an increasingly wide slate of crudes. For the past several years, the Refinery has processed a crude oil slate comprised predominantly of Middle Eastern, Russian and Latin American medium sour crude oils. The Refinery manufactures a full slate of premium products including ultra-low sulphur, gasoline and distillates, and heavy fuel oil. While the nameplate capacity is 115,000 bbl/d, the average daily throughput was 98,081 bbl/d for the year ended December 31, 2013 due to isomax and crude unit outages in October, sulphur recovery unit and hydrocracker unit outage in July and an unplanned outage in February due to a power failure during a storm. For further discussion, refer to Item 5A “Operating Results”.

OTHER

For further information on environmental issues that may affect the utilization of the Upstream and Downstream assets, please see Item 3D “Risk Factors’’ and Item 4B “Business Overview - Environmental Regulations”. The Corporation’s Credit Facility is secured by a first floating charge over all of the assets of Harvest’s Operating Subsidiaries plus a first mortgage security interest on the Downstream operation’s refinery assets. For further information, please see Item 10C “Material Contracts”.

ITEM 4A. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

The information presented has been prepared in accordance with IFRS and should be read in conjunction with Item 3 “Key Information”, and our audited consolidated financial statements and related notes for the years ended December 31, 2013 as set out in this annual report under Item 18.

A. Operating Results

UPSTREAM OPERATIONS

Summary of Financial and Operating Results

	Year Ended December 31		
(in millions except where noted)	**2013**	2012	2011
FINANCIAL			
Petroleum and natural gas sales[(1)]	**$ 1,101.7**	$ 1,193.5	$ 1,286.9
Royalties	**(153.9)**	(164.6)	(195.5)
Revenues	**947.8**	1,028.9	1,091.4

Expenses					
Operating		**345.6**		359.0	350.4
Transportation and marketing		**22.6**		22.2	29.6
Realized gains on risk management contracts[2]		**(4.9)**		(1.6)	(6.0)
Operating netback after hedging[3]		**584.5**		649.3	717.4
General and administrative		**68.1**		65.0	60.8
Depreciation, depletion and amortization		**530.0**		579.5	535.7
Exploration and evaluation		**12.3**		24.9	18.3
Impairment of property, plant and equipment		**24.1**		21.8	–
Unrealized (gains) losses on risk management contracts[4]		**0.5**		1.1	(0.7)
Gains on disposition of property, plant and equipment		**(33.9)**		(30.3)	(7.9)
	$	**(16.6)**	$	(12.7)	$ 111.2
Capital asset additions (excluding acquisitions)	**$**	**322.3**	$	447.5	$ 639.6
Property and business acquisitions (dispositions), net	**$**	**(155.6)**	$	(84.3)	$ 550.9
Decommissioning and environmental remediation expenditures	**$**	**19.4**	$	20.2	$ 21.5
OPERATING					
Light / medium oil (bbl/d)		**11,671**		13,889	14,376
Heavy oil (bbl/d)		**16,905**		19,506	18,995
Natural gas liquids (bbl/d)		**5,345**		5,535	5,062
Natural gas (mcf/d)		**111,313**		122,385	112,360
Total (boe/d)		**52,473**		59,327	57,161

(1) Includes the effective portion of Harvest's realized natural gas and crude oil hedges.

(2) Realized gains on risk management contracts include the settlement amounts for power, crude oil and foreign exchange derivative contracts, excluding the effective portion of realized (gains) losses from Harvest's designated accounting hedges.

(3) This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this annual report.

(4) Unrealized (gains) losses on risk management contracts reflect the change in fair value of derivative contracts that are not designated as accounting hedges and the ineffective portion of changes in fair value of designated hedges.

Commodity Price Environment

	Year Ended December 31		
	2013	2012	2011
West Texas Intermediate crude oil (US$/bbl)	**97.97**	94.21	95.12
Edmonton light sweet crude oil ($/bbl)	**93.04**	86.15	95.18
Western Canadian Select ("WCS") crude oil ($/bbl)	**74.97**	73.09	77.10
AECO natural gas daily ($/mcf)	**3.17**	2.39	3.62
U.S. / Canadian dollar exchange rate	**0.971**	1.001	1.011
Differential Benchmarks			
WCS differential to WTI ($/bbl)	**25.98**	21.03	16.93
WCS differential as a % of WTI	**25.7%**	22.3%	18.0%

The average WTI benchmark price for the year ended December 31, 2013 was 4% higher than the same period in 2012. The average Edmonton light sweet crude oil price ("Edmonton Light") increased 8% for the year ended December 31, 2013 mainly due to the higher WTI prices and the weakening of the Canadian dollar on an annual average basis. Partially offset by the widening of the light sweet differential. The average WTI benchmark price for the year ended December 31, 2012 was 1% lower than the same period in 2011. The average Edmonton light sweet crude oil price decreased 9% for the year ended December 31, 2012 mainly due to the lower WTI prices and widening of the light sweet differential.

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. For the year ended December 31, 2013, the WCS price increased 3% as compared to the same period in 2012 mainly as a result of the increase in the WTI price and the weakening of the Canadian dollar, partially offset by the widening of the WCS differential to WTI. The WCS price decreased 5% in 2012 as compared to 2011 mainly as a result of the widening of the WCS differential to WTI.

Realized Commodity Prices

	Year Ended December 31		
	2013	2012	2011
Light to medium oil prior to hedging ($/bbl)	**85.38**	80.17	88.37
Heavy oil prior to hedging($/bbl)	**74.37**	71.35	76.07
Natural gas liquids ($/bbl)	**57.44**	56.54	67.93
Natural gas prior to hedging ($/mcf)	**3.46**	2.58	3.83
Average realized price prior to hedging ($/boe)(1)	**56.58**	53.60	62.13
Light to medium oil after hedging ($/bbl)(2)	**85.38**	86.00	86.58
Heavy oil after hedging ($/bbl)(2)	**73.84**	71.35	76.07
Natural gas after hedging ($/mcf)(2)	**3.63**	2.58	3.83
Average realized price after hedging ($/boe)(1) (2) (3)	**56.78**	54.97	61.68

(1) Inclusive of sulphur revenue.

(2) Inclusive of the realized gains (losses) from crude oil and natural gas contracts designated as hedges. Foreign exchange swaps and power contracts are excluded from the realized price.

(3) Natural gas liquids prices are not hedged but are included in the average realized price after hedging.

Harvest's realized prices prior to hedging for light to medium oil, heavy oil and natural gas generally trend with the Edmonton Light, WCS and AECO benchmark prices, respectively. For the years ended December 31 shown in the table above, the period-over-period variances and movements in these realized prices were consistent with the changes in the related benchmarks. Natural gas liquids realized prices increased by 2% for the year 2013 as compared to 2012 and decreased by 17% in 2012 as compared to 2011. These movements reflected the changes in natural gas liquids commodity prices.

In order to mitigate the risk of fluctuating cash flows due to natural gas and crude oil price volatility, Harvest entered into AECO and WCS derivative contracts in 2013. Including the impact from the AECO hedges, Harvest's realized gas prices increased by $0.17/mcf in 2013 (2012 & 2011 - $nil). Harvest's realized heavy oil prices decreased $0.53/bbl for 2013 (2012 & 2011 - $nil) as a result of the WCS hedges. There were no light to medium crude oil hedges during 2013, but in 2012 & 2011 Harvest earned a $5.83/bbl increase and a $1.79/bbl decrease in realized light to medium oil prices, respectively. Please see the "Cash Flow Risk Management" section in this item for further discussion with respect to the cash flow risk management program.

Sales Volumes

	Year Ended December 31					
	2013		2012		2011	
	Volume	**Weighting**	Volume	Weighting	Volume	Weighting
Light to medium oil (bbl/d)	**11,671**	**22%**	13,889	23%	14,376	25%
Heavy oil (bbl/d)	**16,905**	**32%**	19,506	33%	18,995	33%
Natural gas liquids (bbl/d)	**5,345**	**10%**	5,535	9%	5,062	9%
Total liquids (bbl/d)	**33,921**	**64%**	38,930	65%	38,433	67%
Natural gas (mcf/d)	**111,313**	**36%**	122,385	35%	112,360	33%
Total oil equivalent (boe/d)	**52,473**	**100%**	59,327	100%	57,161	100%

2013-2012

Total sales volumes were 52,473 boe/d for the year ended December 31, 2013, a decrease of 12% compared to the same period in 2012. The year-over-year decrease in sales was primarily due to natural declines, smaller 2012 and 2013 capital drilling programs and dispositions of certain non-core producing properties in the most recent five quarters.

Harvest's 2013 light to medium oil sales decreased by 16% from 2012 to 11,671 bbl/d. The decrease is mainly due to natural declines, a lower level of drilling activity in both 2012 and 2013 and the disposition of non-core properties.

Heavy oil sales decreased by 13% for the year ended December 31, 2013 compared to 2012 due to the same reasons as light to medium oil, as well as an outage of a major oil battery in Alberta.

For the year ended December 31, 2013, natural gas sales decreased by 9% due to natural declines, property dispositions and facility turnarounds, partially offset by the results of development drilling in the liquids-rich Deep Basin area.

Natural gas liquids sales for the year ended December 31, 2013 decreased 3% compared to 2012 due to natural declines and third party facility constraints.

2012-2011

Total sales volumes were 59,327 boe/d for the year ended December 31, 2012, an increase of 4% compared to the same period in 2011. The year-over-year increase in sales reflects the results of drilling in the liquids rich Deep Basin area, the full year benefit from the assets acquired from Hunt at the end of February 2011 and the current year production recovery from the Plains Rainbow Pipeline outage during the summer of 2011, partially offset by the extended turnaround of a third-party natural gas plant in the Caroline area, generally lower drilling activity in 2012 and the disposition of certain non-core producing properties in the fourth quarter of 2012 which mainly produced light to medium oil.

Harvest's 2012 light to medium oil sales decreased by 3% from 2011 to 13,889 bbl/d. The decrease is mainly a result of the disposition of non-core properties, lower level of drilling activity in 2012 and an extended pipeline outage in the Bashaw area. Heavy oil sales increased by 3% for the year ended December 31, 2012 compared to 2011, mainly due to sales recovering from the Plains Rainbow pipeline outage in 2011.

For the year ended December 31, 2012, natural gas sales increased by 9% due to the full year production from the assets acquired from Hunt in 2011 and the results of development drilling in Willesden Green and the liquids-rich Deep Basin area, partially offset by the extended Caroline plant turnaround in the summer of 2012.

Natural gas liquids sales for the year ended December 31, 2012 increased 9% compared to 2011 for reasons consistent with those describing the natural gas results.

Revenues

	Year Ended December 31		
($ millions)	**2013**	2012	2011
Light to medium oil sales after hedging (1)	**363.7**	437.1	454.3
Heavy oil sales after hedging (1)	**455.6**	509.4	527.4
Natural gas sales after hedging (1)	**147.6**	115.7	156.9
Natural gas liquids sales	**112.1**	114.5	125.5
Other(2)	**22.7**	16.8	22.8
Petroleum and natural gas sales	**1,101.7**	1,193.5	1,286.9
Royalties	**(153.9)**	(164.6)	(195.5)
Revenues	**947.8**	1,028.9	1,091.4

(1) Inclusive of the effective portion of realized gains (losses) from natural gas and crude oil contracts designated as hedges.

(2) Inclusive of sulphur revenue and miscellaneous income.

Harvest's revenue is subject to changes in sales volumes, commodity prices, currency exchange rates and hedging activities. For the year ended December 31, 2013, total petroleum and natural gas sales decreased by 8% mainly due to the 12% decrease in sales volumes and partially offset by the 3% increase in realized prices after hedging activities. For the year ended December 31, 2012, total petroleum and natural gas sales decreased by 7% from the prior year, mainly due to the 11% decrease in realized prices after hedging activities and partially offset by the 4% increase in sales volumes. Sulphur revenue represented $8.5 million (2012 - $16.9 million, 2011 - $21.3 million) of the total in other revenues for the year ended December 31, 2013.

Royalties

Harvest pays 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. For the year ended December 31, 2013, royalties as a percentage of gross revenue averaged 14.0% (2012 - 13.8%, 2011 – 15.2%) . The higher royalty rates in 2011 were mainly due to lower Alberta Crown gas cost allowance credits realized in that year.

Operating and Transportation Expenses

	Year Ended December 31					
($ millions)	**2013**	**$/boe**	2012	$/boe	2011	$/boe
Power and purchased energy	**89.1**	**4.65**	79.6	3.67	83.1	3.98
Well servicing	**49.9**	**2.60**	56.0	2.58	61.6	2.95
Repairs and maintenance	**51.6**	**2.70**	57.0	2.63	60.0	2.88
Lease rentals and property tax	**37.3**	**1.95**	38.3	1.76	34.7	1.66
Labor - internal	**31.8**	**1.66**	31.5	1.45	28.1	1.35
Labor - contract	**15.3**	**0.80**	19.3	0.89	19.4	0.93
Chemicals	**18.7**	**0.98**	18.0	0.83	15.4	0.74
Trucking	**13.9**	**0.72**	16.3	0.74	13.3	0.64
Processing and other fees	**36.8**	**1.92**	33.4	1.54	22.6	1.09
Other	**1.2**	**0.07**	9.6	0.45	12.2	0.58
Total operating expenses	**345.6**	**18.05**	359.0	16.54	350.4	16.80
Transportation and marketing	**22.6**	**1.18**	22.2	1.02	29.6	1.42

Operating expenses for 2013 decreased by $13.4 million compared to the same period in 2012. The lower operating expenses for 2013 were mainly attributable to lower production levels, the impact of asset dispositions and Harvest's implementation of a cost savings and efficiencies program, partially offset by the increase in the cost of Alberta power and higher processing and other fees. Operating costs on a per barrel basis increased by $1.51/boe or 9% for 2013.

Operating expenses for 2012 totaled $359.0 million, an increase of $8.6 million when compared to 2011, mainly due to the increase in processing and other fees and increased production. On a per barrel basis, operating expenses decreased by $0.26/boe or 2% which is mainly attributable to lower well servicing, repairs and maintenance and power and purchased energy costs, partially offset by higher processing and other fees.

Transportation and marketing expenses relate primarily to delivery of natural gas to the Nova Gas Transmission Limited System and the cost of trucking crude oil to pipeline or rail receipt points. As a result, the total dollar amount of costs generally fluctuates in relation to sales volumes. In 2013, additional oil trucking costs were incurred due to the outage of a major oil battery in Alberta and higher gas transportation costs were incurred in the Deep Basin area as compared to 2012. In 2011, Harvest incurred higher oil trucking costs at Hay River and Red Earth in response to the outage of the Plains Rainbow Pipeline during the summer of 2011.

	Year Ended December 31		
($/boe)	**2013**	2012	2011
Power and purchased energy costs	**4.65**	3.67	3.98
Realized gains on electricity risk management contracts	**(0.16)**	–	(0.37)
Net power and purchased energy costs	**4.49**	3.67	3.61
Alberta Power Pool electricity price ($/MWh)	**79.95**	64.29	76.65

Power and purchased energy costs, comprised primarily of electric power costs, represented approximately 26% (2012 – 22%, 2011 – 24%) of Harvest's total operating expenses for the year ended December 31, 2013. The power and purchased energy costs for the year ended December 31, 2013 totaled $89.1 million, an increase of 12% compared to 2012, mainly attributable to the higher average Alberta electricity price. The power and purchased energy costs for the year ended December 31, 2012 totaled $79.6 million, a decrease of 4% compared to 2011, mainly attributable to the lower average Alberta electricity price and partially offset by higher average power consumption.

In both 2013 and 2011 Harvest entered into electricity risk management contracts to reduce the volatility of power and purchased energy costs. See the "Cash Flow Risk Management" section within this item for further discussion of risk management contracts.

Operating Netback[(1)]

($/boe)	Year Ended December 31 **2013**	2012	2011
Petroleum and natural gas sales prior to hedging(2)	**56.58**	53.60	62.13
Royalties	**(8.04)**	(7.58)	(9.37)
Operating expenses	**(18.05)**	(16.54)	(16.80)
Transportation expenses	**(1.18)**	(1.02)	(1.42)
Operating netback prior to hedging(1)	**29.31**	28.46	34.54
Hedging gains (losses)(3)	**0.47**	1.38	(0.16)
Operating netback after hedging(1)	**29.78**	29.84	34.38

(1) This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this annual report.
(2) Excludes miscellaneous income not related to oil and gas production
(3) Hedging gains (losses) include the settlement amounts for natural gas, crude oil and power contracts.

Harvest's operating netback represents the net amount realized on a per boe basis after deducting directly related costs. Operating netback prior to hedging for the year ended December 31, 2013 was $29.31/boe, an increase of $0.85/boe from 2012 mainly due to higher average realized prices, partially offset by higher operating expenses per boe. For the year 2012, the operating netback prior to hedging decreased by $6.08/boe or 18% from 2011. The decrease was primarily attributable to lower realized commodity prices, partially offset by decreases in royalties and operating expenses as compared to the prior year.

General and Administrative ("G&A") Expense

	Year Ended December 31 **2013**	2012	2011
G&A *($ millions)*	**68.1**	65.0	60.8
G&A *($/boe)*	**3.56**	2.99	2.91

In 2013, G&A expenses increased by $3.1 million compared to the prior year mainly due to higher consulting fees. For the year 2012, G&A expenses increased by $4.2 million compared to 2011 primarily due to increased salary expenses and consulting fees. Harvest does not have a stock option program, however there is a long-term incentive program which is a cash settled plan that has been included in the G&A expense.

Depletion, Depreciation and Amortization ("DD&A")

	Year Ended December 31 **2013**	2012	2011
DD&A *($ millions)*	**530.0**	579.5	535.7
DD&A *($/boe)*	**27.67**	26.69	25.68

DD&A expenses for the year ended December 31, 2013 decreased by $49.5 million as compared to 2012 mainly due to the change in Harvest's DD&A accounting estimate, as well as lower sales volumes. See note 3(a) "Change in accounting estimate" of the audited consolidated financial statements under Item 18 of this annual report for a description of the change in estimate affecting the depletion calculation. DD&A expenses for the year ended 2012 increased by $43.8 million as compared to 2011 mainly due to a lower depletable proved developed reserve base and higher sales volumes.

Impairment of Property, Plant and Equipment

For the year ended December 31, 2013, Harvest recognized an impairment loss of $24.1 million (2012 – $21.8 million, 2011 - $nil) against PP&E relating to certain gas properties in the South Alberta gas cash-generating unit ("CGU"), which was triggered by reserves write-down as a result of lower forecast development activities, a decline in the long-term gas prices and reduced estimates of recoverable NGLs from the CGU. The recoverable amount was based on the assets' value-in-use ("VIU"), estimated using the net present value of proved plus probable reserves discounted at a pre-tax rate of 8% (2012 – 10%, 2011 – n/a). Please see note 9 of the audited annual consolidated financial statements under Item 18 of this annual report for further discussion of impairment.

Property Dispositions

During the year ended December 31, 2013, Harvest sold certain non-core oil and gas assets with approximately 2,500 boe/d of production, for cash proceeds of $173.9 million (2012 – $88.5 million, 2011 - $8.7 million). The transactions resulted in a gain of $33.9 million (2012 – $30.3 million, 2011 - $7.9 million), which is recognized in the consolidated statements of comprehensive loss.

Harvest continues with the process of marketing non-core properties for sale, to high-grade its asset portfolio and to monetize some of its assets. The impact to future production from the future dispositions is difficult to predict, given the occurrence and the timing of the transactions cannot be determined with a high level of certainty. The proceeds from any dispositions may be used to manage Harvest's liquidity and to fund future development of core assets.

Capital Asset Additions

	Year Ended December 31		
($ millions)	**2013**	2012	2011
Drilling and completion	**180.9**	236.6	386.4
Well equipment, pipelines and facilities	**100.8**	159.1	195.1
Geological and geophysical	**14.4**	9.7	15.7
Land and undeveloped lease rentals	**6.6**	21.8	18.0
Corporate	**4.6**	1.5	2.2
Other	**15.0**	18.8	22.2
Total additions excluding acquisitions	**322.3**	447.5	639.6

Total capital additions declined each year since 2011 as a greater amount of the annual capital budget was allocated to progress the BlackGold Phase 1 project.

The following tables summarize the wells drilled by Harvest and the related drilling and completion costs incurred in the year. A well is recorded in the table as having being drilled after it has been rig-released, however related drilling costs may be incurred in a period before a well has been rig-released and related completion costs may be incurred in a period afterwards.

($ millions)	Year Ended December 31, 2013		
Area	**Gross**	**Net**	
Red Earth	13.0	12.7	$ 47.5
Hay River	28.0	28.0	37.0
Deep Basin	5.0	3.0	34.0
Western Alberta	13.0	4.6	18.4
Heavy Oil	17.0	17.0	16.6
Suffield	6.0	6.0	10.2
SE Saskatchewan	8.0	8.0	8.8
Cecil	4.0	3.5	7.1
Other areas	2.0	1.3	1.3
Total	**96.0**	**84.1**	**$ 180.9**

	Year Ended December 31, 2012		
Area	**Gross**	**Net**	
Hay River	31.0	31.0	$ 51.3
Heavy Oil	25.0	22.5	21.9
Red Earth	13.0	11.5	48.7
Kindersley	10.0	8.0	6.7
SE Saskatchewan	11.0	10.8	14.2
Western Alberta	11.0	6.4	24.4
Deep Basin	5.0	3.9	42.1
Other areas	10.0	6.8	27.3
Total	**116.0**	**100.9**	**$ 236.6**

Area	Year Ended December 31, 2011 Gross	Net		
Hay River	44.0	44.0	$	55.7
Red Earth	38.0	34.8		98.6
Rimbey/Markerville/West Central	39.0	21.5		74.1
Lloydminster Heavy Oil/ Hayter/ Murray Lake	35.0	32.5		23.2
Kindersley	30.0	28.1		39.1
SE Saskatchewan	13.0	13.0		17.1
Suffield	9.0	9.0		9.6
Peace Arch	8.0	3.1		7.3
Deep Basin	5.0	3.0		26.7
Other areas	18.0	13.3		35.0
Total	**239.0**	**202.3**	**$**	**386.4**

2013

During 2013, Harvest continued to concentrate its drilling activities in its five core growth areas: Cecil, Deep Basin, Hay River, Red Earth and SE Saskatchewan; supplemented with drilling in the strategic revenue generating areas in Western Alberta and the Heavy Oil area. The primary areas of focus for Harvest's Upstream drilling program are as follows:

- Cecil – targeting existing and new oil pools in both the Cecil and Royce fields in the Peace River Arch;
- Deep Basin – participating in or drilling deep, horizontal multi-stage fractured wells to develop the liquids-rich Falher and Montney liquids-rich gas formations;
- Hay River – pursuing heavy gravity oil in the Bluesky formation using multi-leg horizontal oil wells;
- Red Earth – activities are spread across the Loon Lake, Gift, Evi and Golden areas targeting light oil formations primarily in the Slave Point and also the Gilwood;
- SE Saskatchewan – horizontal light oil wells pursuing the Tilston and Souris Valley formations;
- Western Alberta – activities spread across several fields with recent efforts targeting mainly the Cardium, Glauconite, Ostracod, and Notikewin formations; and
- Heavy Oil area – horizontal heavy oil wells in the Lloydminster region of Alberta into the McLaren, Lloydminster, General Petroleum and Sparky formations.

Please refer to Item 4D "Property, Plant and Equipment – Upstream Material Properties" for discussion of Harvest's drilling activities in 2013 by material properties.

2012 & 2011

In 2012 and 2011, Harvest concentrated its drilling activities in the following areas:

- Hay River – pursuing heavy gravity oil in the Bluesky formation using multi-leg horizontal oil wells;
- Heavy oil area – drilling program in the Heavy oil and Provost areas which include Lloydminster, Wildmere, Maidstone, Consort, Delbonita and Suffield;
- Red Earth – targeted the Slave Point and Gilwood light oil formations which were generally completed using multi- stage fracturing technology;
- Peace Arch and Cecil Areas – targeting the oil bearing formation with stage stimulated horizontal wells;
- Western Alberta – activities spread across several fields mainly targeting the Cardium, Glauconite, Ostracod, and Notikewin formations;
- SE Saskatchewan – horizontal light oil wells pursuing the Tilston and Souris Valley formations;
- Kindersley – staged fractured horizontal wells in the Viking Formation; and
- Deep Basin – participating in or drilling deep, horizontal multi-stage fractured wells to develop the liquids-rich Falher formations.

Decommissioning Liabilities

Harvest's Upstream decommissioning liabilities at December 31, 2013 were $709.4 million (2012 - $709.3 million, 2011 - $664.4) for future remediation, abandonment, and reclamation of Harvest's oil and gas properties. Please see note 17 of the audited annual consolidated financial statements under Item 18 of this annual report for further discussion of decommissioning liabilities. The total of our decommissioning liabilities are based on management's best estimate of costs to remediate, reclaim, and abandon our wells and facilities. The costs will be incurred over the operating lives of the assets with the majority being at or after the end of reserve life. Please refer to Item 5F "Tabular Disclosure of Contractual Obligations" for the payments due for each of the next five years and thereafter in respect of our decommissioning liabilities.

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, 2013, Harvest had $379.8 million (2012 - $391.8 million, 2011 - $404.9) of goodwill on the balance sheet related to the Upstream segment, a decrease of $12.0 million as a result of a disposition of certain oil and gas properties (see the "Property Dispositions" section above). 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. Management has assessed goodwill for impairment and determined that there is no impairment at December 31, 2013.

BLACKGOLD OILSANDS

Capital Asset Additions

	Year Ended December 31		
($ millions)	**2013**	2012	2011
Drilling and completion	**13.7**	56.6	23.5
Well equipment, pipelines and facilities	**404.0**	93.1	70.1
Geological and geophysical	**0.6**	1.1	0.1
Pre-operating costs	**0.6**	–	–
Other	**25.6**	13.3	7.5
Total BlackGold additions	**444.5**	164.1	101.2

During 2013, Harvest focused on the construction of the CPF and spent $404.0 million on the related well equipment, pipelines and facilities. As at December 31, 2013 the overall oil sands project was approximately 92% complete. In 2012, Harvest spent $56.6 million drilling 30 gross SAGD producer and injector wells (15 well pairs) and spent $93.1 million on the CPF. In 2011, Harvest invested a total of $101.2 million in engineering, procurement and the drilling of 12 observation wells and the preliminary construction of the CPF and well pads.

Oil Sands Project Development

Harvest is developing its BlackGold oil sands CPF under the engineering, procurement and construction ("EPC") contract. Expected total costs under the EPC contract have been revised upwards to approximately $650 million from an earlier estimate of $590 million due to increased costs as a result of labor shortages, inclement weather and a revised completion schedule. Under the EPC contract, a maximum of approximately $101 million of the EPC costs will be paid in equal installments, without interest, over 10 years commencing on the completion of the EPC work in 2014. The liability is considered a financial liability and is initially recorded at fair value, which is estimated as the present value of all future cash payments discounted using the prevailing market rate of interest for similar instruments. As at December 31, 2013, Harvest recognized a liability of $76.2 million (2012 - $4.7 million, 2011 - $nil) using a discount rate of 4.5% (2012 - 4.5%, 2011 – n/a). Non-cash capital additions are recognized in well equipment, pipelines and facilities as the work is performed and the related deferred EPC liability is recognized. For the year-ended December 31, 2013, $71.5 million of non-cash additions were recorded relating to the EPC contract (2012 –$4.7 million, 2011 - $nil).

Initial drilling of 30 steam assisted gravity drainage ("SAGD") wells (15 well pairs) was completed by the end of 2012. More SAGD wells will be drilled in the future to compensate for the natural decline in production of the initial well pairs and maintain the Phase 1 production capacity of 10,000 bbl/d. Detailed engineering of Phase 1 has been completed. Preliminary construction has been substantially completed, including the building of the CPF plant site, the placement of site equipment and pipe rack module installation. Piping and cabling of the CPF are now ongoing. Commissioning of the CPF and first steam is anticipated in the fourth quarter of 2014. Phase 2 of the project, which is targeted to increase production capacity to 30,000 bbl/d, received all required regulatory approvals in 2013.

As at December 31, 2013, Harvest has incurred costs of $551.7 million on the EPC contract. After the accounting impact of the deferred liability described above, Harvest has recorded $531.6 million of costs for the EPC contract and has recorded $730.9 million of costs on the entire project since acquiring the BlackGold assets in 2010.

The BlackGold project faces similar cost and schedule pressures as other oil sand projects, including shortage of skilled labor and rising costs. Please refer to Item 3D "Risk Factors" for further discussion of risks related to the BlackGold project.

Decommissioning Liabilities

Harvest's BlackGold decommissioning liabilities at December 31, 2013 were $34.3 million (2012 - $19.8 million; 2011 - $1.5 million) relating to the future remediation, abandonment, and reclamation of the SAGD wells and central processing facilities. Please see note 17 of the audited annual consolidated financial statements under Item 18 of this annual report for further discussion of decommissioning liabilities. The total of our decommissioning liabilities are based on management's best estimate of costs to remediate, reclaim, and abandon our wells and facilities. The costs will be incurred over the operating lives of the assets with the majority being at or after the end of reserve life. Please refer to the "Contractual Obligations and Commitments" under Item 5F for the payments due for each of the next five years and thereafter in respect of our decommissioning liabilities.

DOWNSTREAM OPERATIONS

Summary of Financial and Operational Results

	Year Ended December 31		
(in $ millions except where noted)	**2013**	2012	2011
FINANCIAL			
Refined products sales[1]	**4,416.9**	4,752.1	3,302.3
Purchased products for processing and resale[1]	**4,327.4**	4,520.3	3,118.1
Gross margin[2]	**89.5**	231.8	184.2
Expenses			
Operating[3]	**126.4**	121.9	109.3
Power and purchased energy	**106.7**	140.7	117.3
Marketing	**5.4**	4.4	6.3
General and administrative	**0.6**	0.6	1.8
Depreciation and amortization	**82.8**	108.9	91.0
Gain on dispositions of PP&E	**(0.2)**	–	–
Impairment of property, plant and equipment	**458.9**	535.5	–
Operating loss[2]	**(691.1)**	(680.2)	(141.5)
Capital asset additions	**53.2**	54.2	284.2
OPERATING			
Feedstock volume (bbl/d)[4]	**98,081**	103,355	68,046
Yield (% of throughput volume)[5]			
Gasoline and related products	**31%**	31%	32%
Ultra low sulphur diesel and jet fuel	**37%**	40%	40%
High sulphur fuel oil	**29%**	27%	27%
Total	**97%**	98%	99%
Average refining gross margin (US$/bbl)[6]	**1.07**	4.87	5.15

(1) Refined product sales and purchased products for processing and resale are net of intra-segment sales of $555.4 million for the year ended December 31, 2013 (2012 - $569.6, 2011 - $507.8 million), reflecting the refined products produced by the refinery and sold by the marketing division.

(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this annual report.

(3) Operating expense for the year ended December 31, 2012 has been increased by $1.1 million (2011 –$0.9 million) as a result of the retroactive application of accounting standard IAS 19R Employee Benefits. See note 3 of the audited consolidated financial statements included within Item 18 of this annual report for further discussion.

(4) Barrels per day are calculated using total barrels of crude oil feedstock and vacuum gas oil.

(5) Based on production volumes after adjusting for changes in inventory held for resale.

(6) Average refining gross margin is calculated based on per barrel of feedstock throughput.

Refining Benchmark Prices

	Year Ended December 31		
	2013	2012	2011
WTI crude oil (US$/bbl)	**97.97**	94.21	95.12
Brent crude oil (US$/bbl)	**108.75**	111.67	110.89
Argus sour crude index (“ASCI”) (US$/bbl)	**102.02**	106.73	107.35
Brent – WTI differential (US$/bbl)	**10.78**	17.46	15.77
Brent – ASCI differential (US$/bbl)	**6.73**	4.94	3.54
Refined product prices			
RBOB (US$/bbl)	**119.11**	124.01	119.19
Heating Oil (US$/bbl)	**125.76**	130.23	126.11
High Sulphur Fuel Oil (US$/bbl)	**93.15**	99.64	96.87
U.S. / Canadian dollar exchange rate	**0.971**	1.001	1.011

Summary of Gross Margin

	Year Ended December 31								
	2013			2012			2011		
(in $ millions except where noted)		**Volumes (million bbls)**	**(US$/ bbl)**		Volumes (million bbls)	(US$/ bbl)		Volumes (million bbls)	(US$/ bbl)
Refinery									
Sales									
Gasoline products	**1,446.0**	**12.3**	**113.83**	1,529.2	12.8	119.42	1,055.1	9.3	114.57
Distillates	**1,833.2**	**14.5**	**122.76**	2,083.7	16.1	129.24	1,386.0	11.1	126.54
High sulphur fuel oil	**759.3**	**8.3**	**89.28**	899.8	9.5	95.66	556.3	6.1	93.08
Other(1)	**249.4**	**2.2**	**109.39**	116.0	1.0	113.79	135.1	1.2	111.00
Total sales	**4,287.9**	**37.3**	**111.60**	4,628.7	39.4	117.62	3,132.5	27.7	114.51
Feedstock (2)									
Crude oil	**3,645.8**	**33.4**	**105.90**	3,858.3	35.5	108.79	2,350.8	22.4	106.11
Vacuum Gas Oil (“VGO”)	**270.5**	**2.4**	**110.81**	274.3	2.3	117.93	286.5	2.4	118.80
Total feedstock	**3,916.3**	**35.8**	**106.22**	4,132.6	37.8	109.36	2,637.3	24.8	107.36
Other(3)	**332.1**			312.1			368.6		
Total feedstock and other costs	**4,248.4**			4,444.7			3,005.9		
Refinery gross margin(4)	**39.5**		**1.07**	184.0		4.87	126.6		5.15
Marketing									
Sales	**684.4**			693.0			677.7		
Cost of products sold	**634.4**			645.2			620.1		
Marketing gross margin(4)	**50.0**			47.8			57.6		
Total gross margin(4)	**89.5**			231.8			184.2		

(1) Includes sales of vacuum gas oil and hydrocracker bottoms.
(2) Cost of feedstock includes all costs of transporting the crude oil to the refinery in Newfoundland.
(3) Includes inventory adjustments, additives and blendstocks and purchase of product for local sales
(4) This is a non-GAAP measure; please refer to “Non-GAAP Measures” in this annual report.

Throughput analysis

2013-2012

The average throughput rate for the year ended December 31, 2013 was 98,081 bbl/d, a 5% decrease from the 103,055 bbl/d in the prior year. The lower daily average throughput rate for 2013 is a consequence of isomax and crude unit outages in October, the four-week sulphur recovery unit (“SRU”) and hydrocracker unit outage in July to repair a leak on the SRU reactor, an unplanned two-week outage in February due to a power failure during a storm and reduced rates following this outage due to weak economic conditions in the second quarter.

2012-2011

Feedstock throughput of 103,355 bbl/d for the year ended December 31, 2012 is 52% higher than the prior year. The lower daily average throughput rate for 2011 is a consequence of an extended planned maintenance shutdown during the year combined with the reduction in throughput rates in the fourth quarter of 2011. The average daily rate for 2012 is less than the nameplate capacity of 115,000 bbl/d as a consequence of an exchanger leak on the amine unit resulting in an outage of the amine, sulphur recovery and hydrocracker units and reduction in crude rate throughput to approximately 80,000 bbls/day for two weeks combined with an operational issue with the sulphur recovery unit resulting in an unplanned outage of all refinery units for approximately three weeks.

The table below provides a comparison between the product crack spread realized by our refinery and the benchmark crack spread for the years ended December 31, with both crack spreads referring to the price of Brent crude oil.

	Year Ended December 31								
	2013			2012			2011		
	Refinery	**Benchmark[1]**	**Difference**	Refinery	Benchmark[1]	Difference	Refinery	Benchmark[1]	Difference
Gasoline products (US$/bbl)	**7.61**	**10.36[2]**	**(2.75)**	10.06	12.34[2]	(2.28)	7.21	8.30[2]	(1.09)
Distillates (US$/bbl)	**16.54**	**17.01[2]**	**(0.47)**	19.88	18.56[2]	1.32	19.18	15.22[2]	3.96
High Sulphur Fuel Oil (US$/bbl)	**(17.76)**	**(15.60)[3]**	**(2.16)**	(13.70)	(12.03)[3]	(1.67)	(14.28)	(14.02)[3]	(0.26)

(1) Benchmark product crack is relative to Brent crude oil.

(2) RBOB benchmark market price sourced from Platts.

(3) High Sulphur Fuel Oil benchmark market price sourced from Platts. Our high sulphur fuel oil normally contains a higher sulphur content than the 3% content reflected in the benchmark price.

Downstream's product crack spreads are different from the above noted benchmarks due to several factors, including the timing of actual sales and feedstock purchases differing from the calendar month benchmarks, transportation costs, sour crude differentials, quality differentials and variability in the throughput volume over a given period of time. The refinery sales also include products for which market prices are not reflected in the benchmarks. An additional differing factor in 2013 is the cost of RINs that are necessary to meet blending requirements for RBOB gasoline and ultra-low sulphur diesel ("ULSD") in the US market as mandated by the US government and which such costs have increased significantly over 2012. The average RINs cost for the year ended December 31, 2013 was approximately US$2.50/bbl for RBOB gasoline (2012 - US$0.75/bbl, 2011 – US$0.55/bbl) and US$3.00/bbl for ULSD products (2012 - US$0.55/bbl, 2011 - US$0.52/bbl) . Downstream's crack spreads for gasoline products and distillates in the above tables include the actual cost of RINs whereas the benchmarks do not. For more detail on RINs, see Item 3.D "Risk Factors" and Item 4.B "Business Overview" in this annual report.

The overall gross margin is also impacted by the purchasing of blendstocks to meet summer gasolines specifications, additives to meet product specifications, the build of unfinished saleable products which are recorded at a value lower than cost, and inventory write-downs and reversals. These costs are included in "other costs" in the Summary of Gross Margin Table above.

Gross margin analysis

2013-2012

The refinery gross margin for the year ended December 31, 2013 decreased 79% as compared to the prior year. The lower gross margin is a result of decreased product crack spreads combined with lower distillates yield. The lower production and sales in 2013 is mainly the result of the unplanned unit outages during the year. Realized product crack spreads for all product groups were lower for the year due to lower market prices and the increased cost of RINs.

During the year ended December 31, 2013, the Canadian dollar weakened as compared to the US dollar. The weakening of the Canadian dollar in 2013 has had a positive impact to the contribution from the refinery operations relative to the prior year as substantially all of its gross margin, cost of purchased energy and marketing expense are denominated in U.S. dollars.

The gross margin from the marketing operations is comprised of the margin from both the retail and wholesale distribution of gasoline and home heating fuels as well as the revenues from marine services including tugboat revenues and reflects a moderate improvement for the three months and year ended December 31, 2013 as compared to 2012.

2012-2011

The refining gross margin for the fiscal year 2012 decreased slightly by US$0.28/bbl from 2011 mainly due to reduced sour crude differential, partially offset by increased product prices.

The sour crude differential includes transportation costs and the impact of timing of purchases of feedstock under the SOA (2011) that may cause significant variances when measured against a given benchmark. The reduced sour crude differential in 2012 had a negative impact on the overall refinery gross margin. The cost of feedstock for the year ended December 31, 2012 was a US$2.31/bbl discount to the benchmark Brent crude oil as compared to a discount of US$3.53/bbl in 2011.

The gross margin from the marketing operations included the US$10 million settlement from the business interruption claim relating to the fire in the first quarter of 2010.

The exchange rates between the Canadian dollars and the US dollars changed negligibly when comparing 2012 against 2011.

Operating Expenses

	Year Ended December 31								
	2013			2012			2011		
($ millions)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total	Refining	Marketing	Total
Operating cost	**104.8**	**21.6**	**126.4**	101.7	20.2	121.9	89.3	20.0	109.3
Power and purchased energy	**106.7**	**–**	**106.7**	140.7	–	140.7	117.3	–	117.3
	211.5	**21.6**	**233.1**	242.4	20.2	262.6	206.6	20.0	226.6
($/bbl of feedstock throughput)									
Operating cost	**2.92**	**–**	**–**	2.69	–	–	3.60	–	–
Power and purchased energy	**2.98**	**–**	**–**	3.72	–	–	4.72	–	–
	5.90	**–**	**–**	6.41	–	–	8.32	–	–

In 2013 the refining operating cost per barrel of feedstock throughput increased by 9% as compared to the year 2012, reflecting lower throughput volumes in 2013. While in 2012 the refining operating cost per barrel of feedstock throughput decreased by 25% as compared to the year 2011, reflecting higher throughput volumes in 2012.

Power and purchased energy, consisting of low sulphur fuel oil (“LSFO”) and electricity, is required to provide heat and power to refinery operations. The purchased energy cost per barrel of feedstock throughput decreased by 20% during 2013 as compared to 2012, mainly due to a lower volume of purchased energy as a result of a higher consumption of produced fuel, combined with lower prices and lower throughput rates in 2013. The purchased energy cost per barrel of feedstock throughput in 2012 decreased by 21% as compared to 2011, mainly as the result of higher feedstock throughput volumes in 2012.

Capital Asset Additions

Capital asset additions for the year ended December 31, 2013 totaled $53.2 million (2012 - $54.2 million, 2011 - $284.2 million) which related various capital projects. The capital additions were highest in 2011 due to the extended planned turnaround, which cost $102.4 million. Other capital additions in 2011 included catalyst replacement of $32.2 million, tubing and piping replacement of $26.0 million and other significant capital work completed during the turnaround period.

Depreciation and Amortization Expense

	Year Ended December 31		
($ millions)	**2013**	2012	2011
Refining	**79.0**	105.3	87.3
Marketing	**3.8**	3.6	3.7
Total depreciation and amortization	**82.8**	108.9	91.0

Depreciation and amortization expense decreased $26.1 million for the year ended December 31, 2013 as compared to 2012 because of the $535.5 million impairment of refinery property, plant and equipment which occurred in the fourth quarter of 2012. The $17.9 million higher depreciation in 2012 as compared to 2011 is a consequence of the increased capital and turnaround expenditures completed during 2011 which were then depreciated during 2012. The process units are amortized over an average useful life of 20 to 35 years and turnaround costs are amortized to the next scheduled turnaround.

Decommissioning Liabilities

Harvest's Downstream decommissioning liabilities result from the ownership of the refinery and marketing assets. At December 31, 2013, Harvest's Downstream decommissioning liabilities were $16.7 million (2012 - $16.2 million, 2011 - $14.6 million), relating to the reclamation and abandonment of these assets with an expected abandonment date of 2069. Please see note 17 of the audited annual consolidated financial statements under Item 18 of this annual report for further discussion of decommissioning liabilities. Please refer to Item 5F "Tabular Disclosure of Contractual Obligations" for the payments due for each of the next five years and thereafter in respect of our decommissioning liabilities.

Impairment of Property, Plant and Equipment

During 2013, Harvest recorded an impairment of $458.9 million (2012 – $535.5 million, 2011 - $nil) on its refinery CGU relating to the PP&E to reflect the excess of the carrying value over the assessed recoverable amount. The recoverable amount was based on the CGU's VIU, estimated using the net present value of future cash flows and using a pre-tax discount rate of 16% (2012 – 16%, 2011 – n/a). Please see note 9 of the audited annual consolidated financial statements under Item 18 of this annual report for further discussion of impairment, including the key assumptions used and the sensitivity analysis performed on the key assumption.

CORPORATE

Cash Flow Risk Management

The Company at times enters into natural gas, crude oil, electricity and foreign exchange contracts to reduce the volatility of cash flows from some of its forecast sales and purchases, and when allowable, will designate these contracts as cash flow hedges. The following is a summary of Harvest's risk management contracts outstanding at December 31: 2013

Contracts Designated as Hedges *(fair value in $ millions)*

Contract Quantity	Type of Contract	Term	Contract Price	Fair Value
36,750 GJs/day	AECO swap	Jan – Dec 2014	$3.71/GJ	$0.2

Contracts Not Designated as Hedges *(fair value in $ millions)*

Contract Quantity	Type of Contract	Term	Contract Price	Fair Value
30 MWh	AESO power swap	Jan – Dec 2014	$55.29/MWh	($0.5)

2012

Contracts Designated as Hedges *(fair value in $ millions)*

Contract Quantity	Type of Contract	Term	Contract Price	Fair Value
10,800 GJs/day	AECO swap	Jan – Dec 2013	$3.42/GJ	$1.8

2011

Contracts Designated as Hedges *(fair value in $ millions)*

Contract Quantity	Type of Contract	Term	Contract Price	Fair Value
4,200 bbls/day	Crude oil price swap	Jan – Dec 2012	US $111.37/bbl	$19.7
US $468,000/day	Foreign exchange swap	Jan – Dec 2012	$1.0236 Cdn/US	0.5
			Total	$20.2

The following is a summary of Harvest's realized and unrealized (gains) losses on risk management contracts for years ending December 31:

Realized (gains) losses recognized in:	Power	Crude Oil	Currency	Natural Gas	Total
			2013		
Revenues	**–**	**3.3**	**–**	**(7.2)**	**(3.9)**
Risk management (gains) losses	**(3.1)**	**(0.4)**	**(1.4)**	**–**	**(4.9)**
Unrealized (gains) losses recognized in:					
OCI, before tax	–	**3.3**	–	**(5.7)**	**(2.4)**
Risk management (gains) losses	**0.5**	**–**	**–**	**–**	**0.5**

	2012		
Realized (gains) losses recognized in:	Crude Oil	Currency	Total
Revenues	(29.6)	–	(29.6)
Risk management (gains) losses	(2.1)	0.5	(1.6)
Unrealized (gains) losses recognized in:			
OCI, before tax	(12.2)	–	(12.2)
Risk management (gains) losses	1.1	–	1.1

	2011		
Realized (gains) losses recognized in:	Power	Crude Oil	Total
Revenues	–	9.4	9.4
Risk management (gains) losses	(7.7)	1.7	(6.0)
Unrealized (gains) losses recognized in:			
OCI, before tax	–	(16.5)	(16.5)
Risk management (gains) losses	1.0	(1.7)	(0.7)

Financing Costs

	Year Ended December 31		
($ millions)	**2013**	2012	2011
Credit Facility	**20.3**	17.2	7.9
Convertible debentures	**14.9**	47.7	49.6
67/8% senior notes	**37.4**	36.2	35.7
21/8% senior notes(1)	**11.7**	–	–
Related party loans	**8.1**	2.9	–
Amortization of deferred finance charges and other	**2.9**	(0.1)	0.9
Interest and other financing charges	**95.3**	103.9	94.1
Accretion of decommissioning and environmental remediation liabilities	**22.3**	20.7	23.6
Gain on redemption of convertible debentures	**(3.6)**	(0.1)	–
Less: capitalized interest	**(19.8)**	(13.5)	(8.6)
Total finance costs	**94.2**	111.0	109.1

(1) Includes guarantee fee to KNOC. See note 12 c) of the audited annual consolidated financial statements included in Item 18 of this annual report.

Interest expense on Harvest's Credit Facility has been increasing due to the higher average amount of loan principal outstanding as compared to the prior year. The effective interest rate for interest charges on the Credit Facility for the year ended December 31, 2013 was 3.0% (2012 – 3.0%, 2011 – 3.0%) .

Interest expense on the convertible debentures for the year ended December 31, 2013 decreased by $32.8 million as compared to 2012 as a result of two series of convertible debentures being early redeemed in April and one series of convertible debentures being redeemed in June of 2013. A $3.6 million gain was recognized on the early redemptions of the convertible debentures in 2013.

In May 2013, Harvest issued US$630 million 21/8% senior notes resulting in an interest expense and other financing costs of $11.7 million for the year ended December 31, 2013.

Interest expense on the ANKOR related party loan was $8.1 million for the year ended December 31, 2013 (2012 - $2.9 million, 2011 – $nil). In 2011 there were no related party loans outstanding.

During the year ended December 31, 2013, interest expense of $19.8 million was capitalized to BlackGold. In 2012, $13.5 million (2011 - $8.6 million) of interest expense was capitalized relating to both BlackGold and Downstream's debottlenecking project. The increase in capitalized interest for the years shown in the table above were mainly due to increased capital expenditures for the BlackGold project, partially offset by the decrease of qualifying Downstream capital expenditures and a lower weighted average interest rate.

Please refer to note 16(c)(iv) of the audited annual consolidated financial statements under Item 18 for sensitivity analysis on Harvest's exposure to interest rates.

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 the U.S. dollar denominated 67/8% and 21/8% senior notes, the ANKOR related party loan and on any U.S. dollar denominated monetary assets or liabilities. Upon the issuance of the US$630 million 21/8% senior notes during 2013, Harvest has increased its sensitivity to fluctuations in the US/Canadian exchange rate. The Canadian dollar weakened at December 31, 2013 as compared to December 31, 2012 resulting in an unrealized foreign exchange loss of $40.8 million (2012 - $1.2 million gain, 2011 - $2.6 million loss) for the year ended December 31, 2013. Harvest recognized a realized foreign exchange loss of $3.4 million loss (2012 – $0.1 million gain, 2011 - $6.6 million gain) for the year ended December 31, 2013, respectively, as a result of the settlement of U.S. dollar denominated transactions.

The cumulative translation adjustment recognized in other comprehensive income represents the translation of the Downstream operations' U.S. dollar functional currency financial statements to Canadian dollars. During the year ended December 31, 2013 Harvest recognized a gain of $7.9 million (2012 – loss of $17.7 million, 2011 – gain of $21.5 million) as a result of the changes in the Canadian dollar relative to the U.S. dollar at December 31, 2013 compared to December 31, 2012. As Downstream operations' functional currency is denominated in U.S. dollars, the strengthening (weakening) of the U.S. dollar would result in gains (losses) from decommissioning liabilities, pension obligations, accounts payable and other balances that are denominated in Canadian dollars, which partially offset the unrealized losses (gains) recognized on the senior notes, ANKOR loan and Upstream U.S. dollar denominated monetary items.

Please refer to 16(c)(iv) of the audited annual consolidated financial statements under Item 18 for sensitivity analysis on Harvest's exposure to foreign exchange rates.

Deferred Income Taxes

For the year ending December 31, 2013, Harvest recorded a deferred income tax recovery of $64.2 million (2012 – $81.6 million, 2011 – $29.9 million). Harvest's deferred income tax asset (liability) will fluctuate during each accounting period to reflect changes in the temporary differences between the book value and tax basis of assets as well as legislative tax rate changes. Currently, the principal sources of temporary differences relate to the Company's property, plant and equipment, decommissioning liabilities and the unclaimed tax pools. At December 31, 2013, Harvest recognized deferred income tax assets of $148.8 million (2012 - $61.1 million, 2011 – deferred tax liabilities of $54.9 million). For further discussion, see note 19 of the audited consolidated financial statements for the year ended December 31, 2013 under item 18 of this annual report.

2014 OUTLOOK

The following guidance is provided as general information for stakeholders regarding management's expectations for 2014 for the Upstream, BlackGold and Downstream business segments. The guidance information provided is consistent with Harvest's most recent budget information. Readers are cautioned that the guidance information provided within this Outlook may not be appropriate for other purposes and the actual results may differ materially from those anticipated.

Harvest's capital expenditure budget for 2014 is $620 million, comprised of $350 million for Upstream oil & gas operations, $131 million the BlackGold oil sands project, and $139 million for the Downstream refining and marketing business.

Upstream

Production volume is targeted at approximately 48,800 boe/d reflecting natural declines and assets dispositions during 2013 and our 2014 operating costs are expected to average $17.80/boe.

Harvest has not budgeted for asset acquisitions or dispositions. The Company has identified non-core properties for disposition representing approximately 2,400 boe/d of production. Proceeds from dispositions would be used to manage Harvest's liquidity, fund development of core assets and for the acquisition of strategic assets.

BlackGold

Due to extreme winter conditions the project scaled back construction activities during the first quarter of 2014. Harvest anticipates resuming full construction activities in the second quarter of 2014 and has revised the project schedule accordingly. Harvest anticipates construction completion of the 10,000 bbl/d Phase 1 CPF in the second half of 2014 with first steam expected in the fourth quarter of 2014.

Downstream

A turnaround is scheduled for the second half of 2014 and will utilize approximately 60% of the capital budget with the remainder allocated to sustaining and reliability improvement projects.

For the full year 2014, throughput is anticipated to average approximately 92,500 bbl/d, with operating costs and purchased energy costs aggregating to approximately $8.00/bbl.

Harvest continues to evaluate various business opportunities pertaining to the Downstream business including, but not limited to introduction of joint venture partners, disposition in whole or in part as well as multiple economic scenarios for future operations. An outcome or recommendation arising out of this review has not been determined to date.

See Item 4B "Controls and Regulations" and Item 4C "Environmental Regulations" in this annual report for policies that could affect Harvest's operations.

B. Liquidity and Capital Resources

LIQUIDITY

Cash Flow Analysis

The Company's liquidity needs are met through the following sources: cash generated from operations, proceeds from asset dispositions, borrowings under the Credit Facility, related party loans, long-term debt issuances and capital injections by KNOC. Harvest's primary uses of funds are operating expenses, capital expenditures, and interest and principal repayments on debt instruments.

Cash flow from operating activities for the year ended December 31, 2013 was $200.6 million (2012 - $442.8 million, 2011 - $560.5 million). The decreasing trend of cash flow from operations can be explained by the reduction of Upstream's cash contribution and the increase of Downstream's cash deficiency.

For the year ended December 31, 2013, cash contribution from Upstream operations was $518.2 million (2012 - $581.9 million, 2011 - $661.0 million). The decrease between 2013 and 2012 is mainly driven by lower sales volumes, partially offset by higher operating netback per boe. The decrease between 2012 and 2011 is mainly driven by lower operating netback per boe. Please see Item 5A "Operating Netback" for further discussion.

Cash deficiency from Harvest's Downstream operations was $152.4 million (2012 - $41.7 million, 2011 - $49.7 million) for the year ended December 31, 2013. The increase in Downstream's cash deficiency in 2013 was mainly due to lower average refining gross margin per bbl and poorer yield mix, partially offset by decrease in throughput volume as compared to the prior year. In 2012, the $8.0 million improvement in the cash deficiency as compared to 2011 is a result of a higher throughput volume, partially offset by lower average refining margin per bbl and higher operating and purchased energy expenses.

Cash flow from financing activities for the year ended December 31, 2013 was $367.8 million (2012 – $196.0 million, 2011 – $848.7 million). Harvest's net borrowing from the Credit Facility was $293.8 million for the year ended December 31, 2013 (2012 - $135.1 million, 2011 - $343.3 million). Further discussion of Harvest's financing activities liquidity-related events are described below in the "Liquidity Analysis" section.

Cash spent on investing activities for the year ended December 31, 2013 was $576.0 million (2012 – $637.8 million, 2011 - $1,421.6 million). Harvest funded $758.1 million of capital expenditures for the year ended December 31, 2013 (2012 –$661.2 million, 2011 - $1,025.0 million) with cash generated from operating activities, property dispositions and borrowings under the Credit Facility. Further discussion of Harvest's investing activities are described above in the "Capital Asset Additions" sections in each of our three operating segments.

Liquidity Analysis

Harvest had a working capital deficiency of $75.4 million as at December 31, 2013, as compared to a $441.9 million deficiency at December 31, 2012. The change in the working capital position in 2013 was primarily related to the redemption of the 7.25% Debentures Due 2013 which had been classified as $331.8 million current liabilities as at December 31, 2012. Harvest's working capital is expected to fluctuate from time to time, and will be funded from cash flows from operations and borrowings from the Credit Facility and the KNOC subordinated loan, as required.

The following liquidity-related events occurred in 2013 (also see Item 4A "Recent Developments"):

- Effective March 14, 2013, Harvest entered into a Senior Unsecured Credit Facility. Draws under the Senior Unsecured Credit Facility were made for an aggregate amount of US$390 million and were used to fund the early redemptions of Harvest's 7.25% Debentures Due 2014 on April 2, 2013 and its 7.25% Debentures Due 2013 on April 15, 2013. The facility was fully repaid and cancelled during the second quarter.

- Harvest extended the Credit Facility maturity date by one year to April 30, 2017.

- On May 14, 2013, Harvest issued US$630 million senior unsecured notes due May 14, 2018 for net proceeds of US$626.1 million. The notes bear a coupon rate of 21/8%, with interest paid semi-annually on May 14 and November 14 of each year. The notes are unconditionally and irrevocably guaranteed by Harvest's parent company KNOC. Harvest used the proceeds from the senior unsecured notes towards the full repayment of the draws under the Senior Unsecured Credit Facility and on June 13, 2013 early redeemed, at par, the 7.50% Debentures Due 2015.

- On October 18, 2013, the borrowing capacity of the Credit Facility was increased from $800 million to $1.0 billion.

- On December 30, 2013 Harvest entered into a five year $200 million subordinated loan agreement with KNOC and borrowed $80 million thereunder. On February 28, 2014, Harvest borrowed an additional $80.0 million under the subordinated loan agreement. See note 28(a) of the December 31, 2013 annual consolidated financial statements included within Item 18 of this annual report for further information.

- With the full redemption of its convertible debentures during 2013, issuance of the 21/8% senior notes and both the extension and increased capacity of the Credit Facility, Harvest successfully improved its short-term liquidity and lowered future interest expenses.

Harvest ensures its liquidity through the management of its capital structure, seeking to balance the amount of debt and equity used to fund investment in each of our operating segments. Harvest evaluates its capital structure using the same financial covenant ratios as the ones externally imposed under the Company's Credit Facility (see note 12(a) of the December 31, 2013 consolidated financial statements included within Item 18 of this annual report). The Company continually monitors its Credit Facility covenants and actively takes steps, such as reducing borrowings, increasing capitalization, amending or renegotiating covenants as and when required, to ensure compliance. Harvest was in compliance with all debt covenants at December 31, 2013 and the prior period.

If Harvest had fully drawn down the $200 million available under the KNOC subordinated loan agreement and applied the proceeds against its borrowings under the Credit Facility, the "total debt to total capitalization" covenant ratio would have decreased to 51% as at December 31, 2013. Harvest had $211.5 million and $120.0 million of borrowing room under the Credit Facility and KNOC subordinated loan agreement, respectively as at December 31, 2013; Harvest expects to meet its future cash requirements and financial obligations with cash from operations and these undrawn borrowings. However, Harvest's continued liquidity is subject to various risks (see Item 3D "Risk Factors").

CAPITAL RESOURCES

The following table summarizes the Corporation's capital structure as at December 31, 2013 and 2012:

(in $ millions except where noted)	**December 31, 2013**	December 31, 2012	December 31, 2011
Debts			
Credit Facility[1]	**788.5**	494.2	358.9
67/8% senior notes (US$500 million)[2]	**531.8**	497.5	508.5
21/8% senior notes (US$630 million)[2]	**670.1**	–	–
Related party loans (US$170 million and CAD$80 million)[2]	**260.8**	169.1	–
Convertible debentures, at principal amount	**–**	627.2	734.0
	2,251.2	1,788.0	1,601.4
Shareholder's Equity			
386,078,649 common shares issued[3]	**1,939.2**	2,691.9	3,453.7
	4,190.4	4,479.9	5,055.1
Financial Ratios[4][5]			
Senior Debt to Annualized EBITDA	**2.41**	1.10	0.73
Annualized EBITDA to annualized interest expense	**3.62**	n/a	n/a
Senior Debt to Total Capitalization	**22%**	14%	10%
Total Debt to Total Capitalization	**54%**	41%	36%

(1) The Credit Facility net of deferred financing costs is $785.2 million (2012 - $491.3 million, 2011 - $355.6 million).
(2) Face value converted at the period end exchange rate.
(3) 386,078,649 common shares were outstanding as at December 31, 2013, 2012, 2011 and as at April 30, 2014
(4) Calculated based on Harvest's Credit Facility covenant requirements (see note 12 of the December 31, 2013 annual consolidated financial statements within Item 18 of this annual report).
(5) The financial ratios and their components are non-GAAP measures; please refer to the "Non-GAAP Measures" section of this annual report.

The outstanding securities of Harvest consist of the common shares and senior notes. The authorized capital consists of an unlimited number of common shares. All of the outstanding common shares are held by KNOC.

As of December 31, 2013, the most significant restrictions on dividends which could be paid by Harvest exist under the Credit Facility pursuant to provisions restricting Distributions (as defined thereunder). Distributions included dividends on Harvest shares. Under those restrictions, a dividend could be paid as follows:

1. Debt/Annualized EBITDA basis: if the Total Debt (as defined in the Credit Facility) to Annualized EBITDA Ratio after such dividend would not exceed 2.5:1 (including for the purposes of calculations for the ratio, any debt to fund the dividend); Annualized EBITDA should be calculated as at the end of the most recent fiscal quarter prior to the dividend;

2. Cash flow basis: if the aggregate amount of that dividend and any other Distributions previously paid was less than the amount of Annualized EBITDA in excess of aggregate capital expenditures. The aggregate Distributions and aggregate capital expenditures were calculated with respect to a period including the current and three prior fiscal quarters and Annualized EBITDA was calculated for the four most recent fiscal quarters; and

3. Stipulated amount basis: on the basis of an aggregate amount of Distributions since April 29, 2011 not to exceed $150 million. This basis for dividends was further subject to compliance with certain ratios after cumulative Distributions of $100 million.

For the purposes of these calculations, all Distributions by Harvest and restricted subsidiaries are included, and similarly capital expenditures are those of Harvest and restricted subsidiaries.

As of December 31, 2013, the Debt/Annualized EBITDA restriction and the cash flow restriction as described above resulted in no amount of allowed dividends payable by Harvest. However, on the stipulated amount basis, Harvest would be permitted to pay dividends up to $150 million, since no Distribution has been made since April 29, 2011.

Credit Facility

During 2013, the Credit Facility was amended to replace the total debt to annualized EBITDA covenant with an annualized EBITDA to annualized interest expense covenant (see note 12 of the audited annual consolidated financial statements under Item 18). The Credit Facility due date was extended one year to April 30, 2017 and the borrowing capacity was increased from $800.0 million to $1.0 billion. At December 31, 2013, Harvest was in compliance with all covenants under the credit facility. As at December 31, 2013, Harvest had $211.5 million (2012 - $305.8 million, 2011 - $441.1 million) of unutilized borrowing capacity under the Credit Facility. The unused borrowing capacity provided Harvest the flexibility to manage fluctuations in its liquidity needs, including working capital requirements. The Credit Facility was secured by a first floating charge over all of the assets of Harvest and its restricted subsidiaries plus a first mortgage security interest on the Downstream refinery assets, with a further provision which allowed Harvest to obtain a release of such security over certain of its oil sands assets. The most restrictive covenants under Harvest's Credit Facility included an aggregate limitation of $25 million on financial assistance and/or capital contributions to parties other than Harvest or its restricted subsidiaries. The Credit Facility requires standby fees on undrawn amounts and interest on amounts borrowed at varying rates depending on Harvest's Senior debt to Annualized EBITDA ratio.

On April 15, 2014, Harvest amended its Credit Facility primarily to accommodate the progression of partnership and joint venture arrangements for the development of Company lands. Certain elements of the financial covenants were also amended. See Item 10C "Material Contracts" for a summary of the terms of the Credit Facility.

67/8% Senior Notes

Harvest had $531.8 million (2012 - $497.5 million, 2011 - $508.5) of principal amount of US$500 million its 67/8% Senior Notes outstanding at December 31, 2013. The 67/8% Senior Notes are unsecured with interest payable semi-annually on April 1 and October 1 and mature on October 1, 2017. The 67/8% Senior Notes are unconditionally guaranteed by all of Harvest's wholly-owned subsidiaries that guarantee the revolving Credit Facility and every future restricted subsidiary that guarantee certain debt. The 67/8% Senior Notes are redeemable at a redemption price equal to the greater of 100% of the principal amount of the 67/8% Senior Notes being redeemed and a make-whole redemption amount calculated using a discount rate of 50 basis points over the reference treasury rate, plus a make-whole redemption premium, plus accrued and unpaid interest to the redemption date. Harvest may also redeem the notes at any time in the event that certain changes affecting Canadian withholding taxes occur.

There are 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 2.0 to 1. Notwithstanding the interest coverage ratio limitation, the incurrence of additional indebtedness may be permitted under certain incurrence tests. One provision allows Harvest's incurrence of indebtedness under the Credit Facility or other future bank debt in an aggregate principal amount not to exceed the greater of $1.0 billion and 15% of total assets. In addition, the covenants of the senior notes restrict the amount of dividends Harvest can pay to shareholders; no dividends have been paid during the year ended December 31, 2013. At December 31, 2013, Harvest was in compliance with all covenants under the senior notes.

21/8% Senior Notes

On May 14, 2013, Harvest issued US$630 million senior unsecured notes due May 14, 2018 with a coupon rate of 21/8% for net proceeds of US$626.1 million. Interest on the 21/8% senior notes is paid semi-annually on May 14 and November 14 of each year. The senior notes are unconditionally and irrevocably guaranteed by Harvest's parent company KNOC. A guarantee fee of 0.52% per annum of the principal balance is payable to KNOC semi-annually on May 14 and November 14 of each year.

Related Party Loan – KNOC Subordinated Loan

On December 30, 2013, Harvest entered into a subordinated loan agreement with KNOC to borrow up to $200 million at a fixed interest rate of 5.3% per annum. The full principal and accrued interest is payable on December 30, 2018. As of December 31, 2013, Harvest has drawn $80 million from the $200 million available under the loan agreement.

Related Party Loan – ANKOR

Harvest has a related party loan outstanding with the associated company ANKOR in the amount of US$170.0 million at a fixed interest rate of 4.62% . The principal balance and accrued interest is due October 2, 2017.

Convertible Debentures

Harvest's convertible debentures were fully repaid or early redeemed during 2013 (see Item 4A "Recent Developments").

C. Research and Development

Not applicable.

D. Trend Information

Harvest continues to be subject to variations in energy commodity prices. Prices for natural gas have increased since the end of 2013 due to colder than normal weather in key natural gas consuming areas in North America. The forward markets indicate fairly stable natural gas prices over the next several years; actual prices will depend on the usual factors such as weather, demand, supply and several other issues, all of which are beyond Harvest's control. Pricing for natural gas liquids have softened compared to 2012 as the continued focus on the development of liquids-rich natural gas plays has resulted in some capacity restrictions to third party gas liquids pipelines, gas plants and fractionation facilities. Harvest continues to work with third party pipeline and gas plant operators but expects some periodic interruption of natural gas and natural gas liquid production over the next few years until new capacity is brought online.

Crude oil differentials are expected to remain volatile in the short to mid-term reflecting the lag between the addition of new crude oil production, especially from the oil sands and resources plays such the Bakken, and the addition of incremental refining and rail/pipeline take-away capacity to the Gulf Coast, East Coast or West Coast of North America. Harvest and third party infrastructure, particularly pipelines, require ongoing maintenance and replacement due to corrosion and age. Harvest will continue to invest capital in these projects to support base production in our more mature fields.

Demand for refined oil products has shifted as the pace of economic recovery in the United States and Europe has been uneven compared to Asian economies. Demand in Asia, led by China and India, shows the most robust growth. Gasoline demand in the United States continues to be weak while gasoline demand is rising in Latin America, most notably Mexico and Brazil. Demand for diesel has been supportive in the United States and Europe and rising across Asia and Latin America.

Growing global demand for and tight supplies of crude oil have increased prices and encouraged oil production. Advances in production techniques, combined with lagging pipeline capacity to take Canadian crude oil to market, have created pricing benchmark disparities in the market crudes. Social unrest and political tensions in the Middle East add more uncertainty. The result is narrowing quality differentials for sour crudes as the emerging Asian economies fulfill their requirements. Global investment in refining capacity has been more significant in the Far East as weak refining margins in the United States Atlantic Coast and Europe have not supported investments to expand capacity and have led to a number of refinery closures. There is currently as much as one million barrels per day of new US refinery capacity in the form of condensate splitters that are either planned or already under construction. These facilities are being pushed as a way to handle the lighter gravity crude in the U.S. produced by fracking technology and to circumvent the crude export ban by exporting products. Any growth in domestic production in Canada and in the U.S. will be offset by a decrease in imported crude oil over the long-term, although the short term may see a crude surplus until supply and demand fall into sync. Crude oil prices will likely be lower in North America than Asia-Pacific due to logistics and political influence. Similarly, refined product prices may be lower in the Atlantic Basin than Asia-Pacific, which may encourage export activities. Once crude oil is able to access water it achieves a global price adjusted for transportation and quality.

The above trend information is based on assumptions that management believes to be reasonable in the light of the group's operational and financial experience. However, no assurance can be given that the above trends will be realized. You should not rely on past performance as an indicator of future performance. You are urged to read the risks associated with Harvest refer to Item 3D "Risk Factors".

E. Off-Balance Sheet Arrangements

None

F. Tabular Disclosure of Contractual Obligations.

Harvest has recurring and ongoing contractual obligations and commitments entered into in the normal course of operations including the purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, and land lease obligations. As at the end of December 31, 2013, Harvest has the following significant contractual commitments:

(millions of Canadian dollars)	Payments Due by Period 1 year	2-3 years	4-5 years	After 5 years	Total
Debt repayments[1]	12.3	–	2,243.3	–	2,255.6
Debt interest payments[1][2]	76.8	153.3	121.6	–	351.7
Purchase commitments[3]	75.5	20.0	70.0	–	165.5
Operating leases	11.8	8.6	6.2	2.8	29.4
Firm processing commitments	9.0	32.2	27.0	97.7	165.9
Firm transportation agreements	9.6	38.8	49.9	92.2	190.5
Feedstock and other purchase commitments[4]	927.8	–	–	–	927.8
Employee benefits[5]	2.6	5.2	1.2	3.8	12.8
Decommissioning and environmental liabilities[6]	35.6	60.7	42.9	1,485.7	1,624.9
Total	1,161.0	318.8	2,562.1	1,682.2	5,724.1

(1) Assumes constant foreign exchange rate.

(2) Assumes interest rates as at December 31, 2013 will be applicable to future interest payments.

(3) Relates to drilling commitments, BlackGold oil sands project commitment and Downstream capital commitments.

(4) Includes commitments to purchase refinery crude stock and refined products for resale under the supply and offtake agreement with Macquarie Energy Canada Ltd. ("Macquarie"). The amount will be net settled against any product sales to Macquarie as per the master netting arrangement.

(5) Relates to the expected contributions to employee benefit plans and long-term incentive plan payments.

(6) Represents the undiscounted obligation by period.

G. Safe Harbor

See "SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS."

ITEM 6. DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

A. Directors and Senior Management

The names, jurisdiction of residence, present positions and offices with Harvest and principal occupations during the past five years of the directors and executive officers of Harvest Operations as at the December 31, 2013 are set out in the table below.

Name and Jurisdiction of Residence	Position with Harvest Operations	Principal Occupation(s) and Other Relevant Experiences
Allan Buchignani Alberta, Canada	Director since May 2013	Mr. Buchignani is an accomplished executive with extensive experience in operations, strategic planning, P&L management and team building. Since 2009, he has acted as a consultant utilizing his leadership and business experience to advise management teams. From 2001 to 2009, Mr. Buchignani held senior positions with ENMAX Corporation and ENMAX Power Corporation. He has been a member of the STARS, Stoker Resources Ltd. and Furry Creek Power Ltd. boards.
Randall Henderson Alberta, Canada	Director since May 2013	Mr. Henderson is a senior finance executive and corporate director who has consulted to the boards of directors and executive management teams of both publicly -traded and private entities since 2005. He is President of Henderson Corporate Financial Consulting Inc. Mr. Henderson has been a director and chairman of the audit committees of Cortex Business Solutions Inc. since 2010 and PGNX Capital Corp. since 2008.

Name and Jurisdiction of Residence	Position with Harvest Operations	Principal Occupation(s) and Other Relevant Experiences
Chang-Seok Jeong Seoul, South Korea	Director since January 2012 and appointed Chairman of the Board in August 2013	Mr. Jeong has been Executive Vice President of Production Group at KNOC since January 2012. Mr. Jeong worked in the Vietnam Office, Asia & Europe Production Department and the Overseas E&P Department as a General Manager & Managing Director from 2009 to 2011.
Chang-Koo Kang Alberta, Canada	Director since January 2010; Chief Financial Officer since January 2012	Mr. Kang was the Vice President of KNOC's Finance Management Department form January 2010 to December 2011. Prior to this, he held the position of Finance Team Senior Manager at KNOC from 2007.
Richard Kines Alberta, Canada	Director since May 2013	Mr. Kines currently consults in senior financial executive roles. He has over 35 years of business experience in the upstream and downstream sectors of the oil and gas industry. From 2002 to 2012 Mr. Kines served as Vice President of Finance and Chief Financial Officer at Connacher Oil and Gas Limited.
Kyungluck Sohn Seoul, South Korea	Director since November 2010	Mr. Sohn is the Vice President, Finance Management Department at KNOC. He was the Chief Financial Officer of Harvest from February 16, 2010 to January 13, 2012. Mr. Sohn served as a Vice President of KNOC's Finance Management department in 2009.
Eugene Synn Seoul, South Korea	Director since August 2013	Mr. Synn is currently a director and Special Advisor of KNOC. Prior thereto, he was the Executive Vice President for Exploration Group & Director of Dana Petroleum plc. from 2012 to 2013 and the Executive Vice President for Europe & Africa Group from 2010 to 2012. Prior to this, he held the Vice President for New Venture & Exploration from 2006 to 2010.
Myunghuhn Yi Alberta, Canada	Director since December 2010; President & Chief Executive Officer since January 2012	Mr. Yi was the Executive Vice President for the Americas Group, as well as President of ANKOR E&P Holdings Corporation in the USA from May 2008 to January 2012.
Leslie G. Hogan[(1)] Alberta, Canada	Chief Operating Officer since November 2012	Previous to his appointment as Chief Operating Officer in November 2012, Mr. Hogan was Harvest's Vice President, Land since December 2007.
Yongseok Kim Alberta, Canada	Deputy Chief Operating Officer since December 2012	Mr. Kim held the position of General Manager, Operations Excellence Team from March 2012 to December 2012. Before joining Harvest, he held the position of VP Engineering at Ankor USA from 2008 to February 2012.

Name and Jurisdiction of Residence	Position with Harvest Operations	Principal Occupation(s) and Other Relevant Experiences
Piljong Sung Alberta, Canada	Chief Strategy Officer & Corporate Secretary since August 2013	Mr. Sung is currently the Chief Strategy Officer of Harvest. Prior thereto, he was a Senior Manager of Exploration & Production Auditing Team from 2007 to 2013 at KNOC.
Patrick BH An Alberta, Canada	Vice President, BlackGold since December 2011	Prior to joining Harvest Mr. An was Senior Manager of Production Assets in the Middle East and the Commonwealth of Independent States from 2009 to 2011 at KNOC.
Gary Boukall Alberta, Canada	Vice President, Geosciences since 2007	From December 2002 to March 2007, Mr. Boukall held various positions with Harvest Operations including Chief Geologist, Manager of Geology and Manager of Geosciences.
Phil Reist Alberta, Canada	Vice President, Controller since 2007	Mr. Reist was Controller of Harvest Operations from February 2006 to March 2007.
Doug Reynolds Alberta, Canada	Vice President, Land since November 2012 and Vice President, Land and New Business Development since December 2013	Mr. Reynolds joined Harvest Operations in April 2011 as Manager, Land Negotiations. Before joining Harvest, he held various senior level managerial positions, including President of his own land consulting company from October 2010 to March 2011. Mr. Reynolds was also Founder, President & CEO and Board Member of his own private oil and gas company, Northern Hunter Energy Inc. from September 2006 to April 2010.
Richard Suffron Alberta, Canada	Vice President, Operations since November 2012	Mr. Suffron joined Harvest Operations in 2007 as the Production Engineering Manager.
Grant Ukrainetz Alberta, Canada	Vice President, Treasurer since February 2013	Prior to joining Harvest in 2012 as Treasurer, Mr. Ukrainetz was Treasurer then VP Corporate Development at Connacher Oil and Gas Limited from 2006 to 2012.
Kim Urban Alberta, Canada	Vice President, Acquisitions and Divestitures and Joint Ventures since December 2013	Ms. Urban has worked for Harvest for over 5 years and was appointed Vice President, Acquisitions & Dispositions and Joint Ventures in December 2013. Prior to her promotion, she held the positions of Director, Acquisitions & Divestitures and Joint Ventures and Manager, Acquisitions & Divestitures.
Doug Walker Alberta, Canada	Vice President, Engineering since November 2012	Mr. Walker joined Harvest in August 2010 as Area Manager, Peace River Arch and SE Saskatchewan. Prior to joining Harvest, Mr. Walker was the North West and West Central Alberta Team Leader at Provident Energy from 2007 to 2010. Mr. Walker's prior industry experience includes technical, business and senior management positions with Noise Solutions, Stellarton Energy, Jordan Petroleum and Gulf Canada Resources.

(1) On March 20, 2014, Mr. Leslie G. Hogan resigned as Chief Operating Officer, effective March 31, 2014.

As at December 31, 2013, none of the directors and executive officers of Harvest Operations and their associates and affiliates, directly or indirectly, beneficially owned, controlled or directed any of the outstanding shares of Harvest Operations. 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. 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. Any such conflicts shall be resolved in accordance with the procedures and requirements of the relevant provisions of the ABCA, including the duty of such directors and officers to act honestly and in good faith with a view to the best interests of Harvest.

Committees of the Board of Directors

Name of Director	Audit Committee	Upstream Reserves, Safety & Environment Committee	Downstream Operations, Safety & Environment Committee	Compensation and Corporate Governance Committee
Allan Buchignani	x	Chair		
Randall Henderson	Chair			x
Chang-Seok Jeong				Chair
Chang-Koo Kang			x	
Richard Kines	x	x	Chair	
Kyungluck Sohn				x
Eugene Synn				x
Myunghuhn Yi		x	x	

Notes:

- On January 25, 2013, Mr. Brian Kwak resigned as Vice President Global Technology Research Centre ("GTRC").
- On February 28, 2013, Mr. Kang Hyun Shin resigned as a director.
- On April 5, 2013, Mr. Brant Sangster resigned as a director removing himself as Chairs of the Audit Committee and Downstream Operations, Safety & Environment Committee.
- On April 17, 2013, Mr. William A. Friley resigned as a director removing himself as Chair of the Upstream Reserves, Safety & Environment Committee.
- Messrs. Leslie G. Hogan and Mark E. Tysowski served as directors from April 18, 2013 to May 6, 2013.
- On May 8, 2013, Mr. Randall Henderson was appointed as Chair of the Audit Committee and Messrs. Allan Buchignani and Richard Kines were appointed members of the Audit Committee. Mr. Henderson was also appointed to the Compensation and Corporate Governance Committee. Mr. Buchignani was appointed as Chair of the Upstream Reserves, Safety and Environment Committee and Mr. Richard Kines was appointed as a member to the Upstream Reserves, Safety and Environment Committee. Mr. Richard Kines was appointed as Chair of the Downstream Operations, Safety and Environment Committee.
- On July 31, 2013 Mr. Hong Geun Im resigned as director removing himself as Chairman of the Harvest Board and Chair of the Compensation and Corporate Governance Committee.
- On August 9, 2013, Mr. Jongwoo Kim resigned as Chief Strategy Officer & Corporate Secretary.
- As of August 28, 2013, Mr. Chang-Seok Jeong was appointed Chairman of the Harvest Board and Chair of the Compensation and Corporate Governance Committee. Mr. Eugene Synn was appointed as a member of the Compensation and Corporate Governance Committee.
- In February 2014, Mr. Taeheon Jang was appointed Acting Vice President, Global Technology & Research Centre.

B. Compensation

COMPENSATION COMMITTEE AND CORPORATE GOVERNANCE COMMITTEE

At December 31, 2013, the Compensation and Corporate Governance Committee is comprised of Kyungluck Sohn, Chang-Seok Jeong, Eugene Synn and Randall Henderson The Compensation and Corporate Governance Committee ("CCGC") is responsible for establishing and overseeing the administration of Harvest's compensation program. The members of the CCGC have the skills and knowledge required to make decisions on the suitability of the Corporation's compensation policies and practices by virtue of their experience as senior officers or directors of public and private companies. The CCGC approves and makes recommendations to Harvest Board in respect of compensation and human resources issues relating to directors, executive officers and employees of Harvest as well as senior officer succession and development. Specific responsibilities of the CCGC relating to executive compensation are documented in the CCGC Mandate and listed below:

- to review the compensation philosophy and remuneration policy for employees of Harvest and to recommend to the Harvest Board changes to improve Harvest's ability to recruit, retain and motivate employees;
- to establish the goals and objectives of the CEO and annually review the performance of the CEO relative to the corporate goals and objectives for the purpose of determining the compensation of the CEO and evaluate the CEO's performance in light of those corporate goals and objectives.
- to annually review and approve the recommendations of the CEO concerning overall compensation and other conditions of employment of the Corporation's officers and employees, satisfy itself that the overall compensation is in accordance with the business plans of the Corporation and with generally accepted compensation levels with comparable companies. The committee may recommend approval to the Boards based on the committee's discretion; and
- to assist the Board in connection with issues relating to succession planning, including appointing, training and monitoring the development and performance of the senior officers of Harvest.

The CCGC, when making compensation determinations, takes into consideration the compensation amount, elements and structure paid to executives of other similarly sized oil and gas companies with a view to ensuring that Harvest's overall compensation packages are competitive. The CCGC utilizes compensation information from annual participation in the Mercer Total Compensation Survey ("MTCS") for the Energy Sector (Canada) published by Mercer Canada ("Mercer"). The MTCS provides a comprehensive perspective on the energy industry reward levels in Canada for any size of organization in any sector of the industry. Mercer, and its parent organization Mercer Global, are leaders in consulting in the area of human resources. Please see appendix C for the peer groups that participated in the MTCS.

COMPENSATION DISCUSSION AND ANALYSIS

Compensation of Officers and Management

<u>ELEMENT OF COMPENSATION</u>

The discussion in this section is applicable to all Harvest executives except for the CEO and the CFO. For information regarding the CEO's and the CFO's compensation, see "Compensation Summary" sections herein. The incentive programs (short-term and long-term) are available to all permanent employees of the Upstream and BlackGold segments, except for KNOC secondees, and the following discussion of incentives describes the programs generally and with the respect to the executives specifically, as applicable.

Base Salaries

Base salaries for the executives are determined with reference to comparable marketplace salaries, as published by Mercer. To be competitive with peer companies, Harvest sets base salary levels at the median of the MTCS for the relevant roles and responsibilities. In addition to the information published by Mercer, base salaries are further adjusted based on an overall determination of Harvest's and the individual's performance. The individual's skill set, experience and expertise are also considered. The CCGC has not established additional strict predetermined quantitative performance criteria linked to the setting of salary levels.

Short-term Incentive Program

At the end of each year, a short-term incentive pool is established by the CCGC after careful consideration of the corporate performance, market information from the MTCS and other qualitative factors. To assess corporate performance, comparisons are made to performance metrics specific to corporate operational goals and relative to industry comparison. The annual pool is shared by all eligible employees, including the executives. Individuals' performances are factored into the allocation process.

Executives' performance is evaluated annually by the CEO, CFO or COO, depending on the direct reporting relationships, based on subjective goals and measures. Recommendations on executives' salary adjustments and short-term incentives are presented to the CCGC, together with their performance evaluations. The CCGC reviews such recommendations and makes compensation decisions accordingly. The CCGC has not established strict predetermined quantitative performance criteria linked to the value of short-term incentives. Bonuses for individuals are also compared with the MTCS information, to ensure the awards are competitive with Harvest's peers.

Long-term Incentive Program

Each eligible employee is granted an annual long-term incentive payment target, expressed as a percentage of base salary. The target set for each employee reflects the individual's roles, responsibilities, skill sets, expertise, relevant experience and past performance. The executives' targets are set at higher levels so that a larger portion of their compensation is performance-based, compared to that for employees. The CCGC determines an annual adjustment factor up to a maximum of 100%, which is applied to every employee's target to calculate the long-term incentive awards. The awards vest over three years, with one-third of the award vesting on the grant date and each of the next two anniversaries of the grant date. Effective for the 2012 year, the long-term incentive program was modified, such that awards will have a grant date of March 1st. The vesting date for the remaining portions of the 2010 and 2011 awards remains January 1st. The modification provides the CCGC with a longer period between the year-end and the grant date so that the CCGC has more complete information to assess corporate performance.

The CCGC considers, among many things, the achievement of certain performance metrics, when making decisions about the adjustment factor. The performance metrics are selected to align with the goals and objectives approved by the shareholder and are subject to change year over year. For 2012, Harvest assessed the following performance metrics as part of the corporate performance review: Upstream production, reserves, finding, development and acquisition costs on a per boe basis ("F&D costs"), Upstream EBITDA, Upstream operating costs on a per boe basis, and Upstream safety (lost time injury frequency). For 2013, the new metrics that were approved by the shareholder include Upstream revenue, seismic spendings, and operating income, while F&D costs and Upstream EBITDA will no longer be considered as key metrics. In addition to corporate performance, the CCGC also takes into consideration the competitive industry environment, peers' compensation information from the MTCS, historical corporate performance of Harvest, achievements of other financial and business strategies, and other relevant qualitative factors. The CCGC has not established any formulae to link the performance metrics to the annual adjustment factor, which therefore is subject to the CCGC's discretion.

COMPENSATION SUMMARY

The following table sets forth for the year ended December 31, 2013 information concerning the compensation paid to Harvest's executive officers and senior management.

			Non-Equity Incentive Plan Compensation ($)			
Name and Principal Position	**Year**	**Salary ($)**	**Annual Incentive Plans (1)**	**Long-term Incentive Plans**	**All Other Compensation(2)**	**Total Compensation ($)**
Myunghuhn Yi	2013	249,256	156,070	Nil	65,730(4)	471,056
Chief Executive Officer(3)	2012	205,956	Nil	Nil	44,398	250,354
	2011	Nil	Nil	Nil	Nil	Nil
Chang-Koo Kang	2013	69,469	9,025	Nil	319,946(5)	398,440
Chief Financial Officer(3)	2012	50,768	7,966	Nil	337,122	395,856
	2011	Nil	Nil	Nil	Nil	Nil
Les Hogan(7)	2013	290,000	145,000	115,573	51,600	602,173
Chief Operating Officer	2012	236,329	61,800	Nil(6)	38,372	336,501
	2011	223,840	55,000	114,521	39,742	433,103
Phil Reist	2013	232,366	59,750	104,309	35,232	431,657
VP, Controller	2012	239,000	59,750	Nil(6)	36,307	335,057
	2011	235,043	60,000	120,253	31,522	446,818
Richard Suffron	2013	227,000	57,000	81,289	41,453	406,742
VP, Operations	2012	214,292	56,750	Nil(6)	35,968	307,010
	2011	200,625	40,000	78,694	33,896	353,215

(1) The annual incentive plan amounts were paid during the year except for Messrs. Hogan, Reist and Suffron's annual incentive plan amounts, which were paid shortly after the end of the fiscal year.
(2) Includes benefits like living, vehicle and housing allowances, the payment of income taxes, contributions to a savings plan and other benefits.
(3) Mr. Yi and Mr. Kang are directors of Harvest Operations, but did not receive compensation for their services as directors.
(4) Mr. Yi received a housing allowance perquisite in the amount of $48,000 in 2013, which comprised 73% of the total perquisites earned by Mr. Yi in the year.
(5) Mr. Kang received a perquisite relating to the payment of income taxes in the amount of $194,424 in 2013, which comprised 61% of the total perquisites earned by Mr. Kang in the year.
(6) Due to the change in the long-term incentive program for 2012, as discussed in the "Long-term Incentive Program" section above, the 2012 long-term incentive was communicated and granted subsequent to December 31, 2012. One third of these amounts was paid in 2013; one third will be paid in 2014, with the remainder to be paid in 2015
(7) On March 20, 2014, Mr. Hogan resigned as Chief Operating Officer, effective March 31, 2014.

Compensation of Directors

The independent directors of Harvest Operations Corp. were paid an annual retainer of $32,000. Committee chairmen were paid an annual retainer of $35,000, except for the Audit Committee chairman who was paid $37,000. In addition, the independent directors were paid $1,000 for each board meeting attended and $1,000 for each committee meeting attended. If an independent director attended two meetings on the same date, the independent director received $500 for the second meeting. The committee chairmen were paid $1,500 for each committee meeting attended. Independent directors are also eligible to receive an annual cash bonus of $10,000, which is not performance-based. Each such director was entitled to reimbursement for expenses incurred in carrying out his duties as director.

The following table sets forth all compensation provided to the independent directors of Harvest Operations for the most recently completed financial year ended December 31, 2013. The non-independent directors received no compensation for carrying out their duties as directors.

Name	Fees Earned ($)
Allan Buchignani	38,089
Randall Henderson	42,401
Richard Kines	43,089
William A. Friley[(1)]	33,594
Brant Sangster[(2)]	36,718

TERMINATION BENEFITS

Harvest has entered into an executive employment agreement with Mr. Yi, CEO, effective March 5, 2012. The agreement provides that, in the event of termination following the first year of employment, other than in the case of disability, but including for cause termination or resignation of Mr. Yi, he shall be entitled to a cash payment equal to the sum of his monthly base salary and 1/12 of his average annual bonus, multiplied by the number of completed years of employment. Under this agreement, completed years of employment are calculated to include fractional years.

The estimated termination payment for Mr. Yi at December 31, 2013 was $61,474.

If the employment of Mr. Yi is terminated due to a permanent disability (within the meaning of the employment agreement), he shall be entitled to receive payment of any earned but unpaid base salary, but shall not be entitled to receive any bonus, severance or termination pay or any other form of compensation for loss of employment.

Harvest has also entered into an executive employment agreement with Mr. Hogan, COO, effective November 8, 2012. The agreement provides that, in the event of termination of employment without cause, Mr. Hogan shall be entitled to receive a cash payment equal to a multiple of his total monthly compensation, where total monthly compensation is calculated as 1/12 of the aggregate of (i) his then annual base salary, (ii) an amount equal to 20% of annual base salary for loss of benefits and contribution to the savings plan and (iii) an amount equal to the average annual bonus payments made in the two prior years (or the last annual bonus or a reasonable estimate thereof if only one bonus year or no bonus year has been completed, as the case may be), plus the amount Mr. Hogan's long-term incentive plan related to prior years and unpaid as of the date of the termination, which vest upon termination on the last day actively work. Following completion of one year of employment under this agreement, the agreed multiple is 15 with an increment of one for each full or partial year of service under the agreement to a maximum of 18.

The estimated termination payment for Mr. Hogan at December 31, 2013 without cause was $679,473.

If the employment of Mr. Hogan is terminated for cause or in the event of permanent disability (within the meaning of the employment agreement), or if he voluntarily resigns his employment, he would be entitled to receive payment of any earned but unpaid base salary and accrued vacation, but would not be entitled to receive any bonus, severance or termination pay or any other payment for loss of employment. On March 20, 2014, Mr. Hogan resigned as Harvest's Chief Operating Officer, effective March 31, 2014.

There are no agreements providing for benefits upon termination of employment/service for any other employees or directors.

C. Board Practices

TERM OF OFFICE

Directors are elected or appointed yearly at the annual meeting and the terms of office of all directors expire at the following annual meeting; see Item 6A above for the period that each Director has served in their current term of office.

AUDIT COMMITTEE

At December 31, 2013 the members of the Audit Committee were Randall Henderson, Allan Buchignani and Richard Kines.

Name (Director Since)	Principal Occupation & Biography
Randall Henderson (May 2013) <u>Other Canadian Public Board of Director Memberships</u> Cortex Business Solutions Inc. PGNX Capital Corp.	Mr. Henderson is a senior finance executive and corporate director who consults to the Board of Directors and executive management teams of both publicly - traded and private entities. He is President of Henderson Corporate Financial Consulting Inc. and a director and chairman of the audit committees of Cortex Business Solutions Inc. and PGNX Capital Corp. Since 2001, Mr. Henderson has served in either a full-time or consulting capacity as the Chief Financial Officer of several significant public and private entities. In 2003, he was nominated for Canada's CFO of the Year Award. He is a member of the Canadian Institute of Chartered Accountants (CICA) and is an executive leadership program alumnus of the Stanford Business School of Stanford University. In 2008, he was awarded the Corporate Finance (CF) designation by the CICA. In 2009, he successfully completed the Directors Education Program offered by the Institute of Corporate Directors of Canada and was awarded its designation of ICD.D.
Allan Buchignani (May 2013) <u>Other Canadian Public Board of Director Memberships</u> N/A	Mr. Buchignani is an accomplished executive with extensive experience in operations, strategic planning, P&L management and team building. Currently, he acts as a consultant utilizing his leadership and business experience to advise management teams. From 2001 to 2009, Allan held senior positions with ENMAX Corporation and ENMAX Power Corporation. He has been a member of the STARS, Stoker Resources Ltd. and Furry Creek Power Ltd. boards. He holds a Bachelor of Science degree in Mechanical Engineering from Washington State University and is a Registered Professional Engineer. In addition, he has completed the Institute of Corporate Directors Designation and the Institute of Corporate Directors Financial Literacy Program.
Richard Kines (May 2013)	Mr. Kines is a senior financial executive with over 35 years of business experience in the upstream and downstream sectors of the oil and gas industry,

Other Canadian Public Board of Director Memberships N/A	the oil and gas services industry, merchant banking and public accounting service sector in domestic and internal arenas. Over the past 25 years he has served as a Vice President of Finance and / or Chief Financial Officer with public and private companies. Mr. Kines is a graduate of the Institute of Corporate Directors, a Chartered Accountant and holds a Bachelor of Commerce degree from the University of Saskatchewan.

The mandate and terms of reference under which the Audit Committee operates are as follows:

ROLE AND OBJECTIVE

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

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

2. to ensure that Harvest complies with all applicable laws, regulations, rules, policies and other requirements of governments, regulatory agencies and stock exchanges relating to financial reporting and disclosure;

3. to enhance that Harvest's accounting functions are performed in accordance with a system of internal controls designed to capture and record properly and accurately all of the financial transactions;

4. to provide better communication between directors and external auditor(s);

5. to enhance the external auditor's independence;

6. to increase the credibility and objectivity of financial reports; including that such reports are accurate within a reasonable level of materiality and present fairly Harvest's financial position and performance in accordance with generally accepted accounting principles consistently applied; and

7. to strengthen the role of the outside directors by facilitating in depth discussions between directors on the Audit Committee, management and external auditor(s).

MEMBERSHIP OF COMMITTEE

1. The Audit 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 "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "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. All of the members of the Audit 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.

3. Unless otherwise designated by the Board, the members of the Audit Committee shall elect a Chairman from among the members and the Chair shall preside at all meetings of the Audit Committee.

MANDATE AND RESPONSIBILITIES OF AUDIT COMMITTE

1. It is the responsibility of the Audit Committee to oversee the work of the external auditor(s), including resolution of disagreements between management and the external auditor(s) regarding financial reporting.

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

- identifying, monitoring and mitigating business risks; and
- ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Audit 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:

    - 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;
    - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
    - reviewing accounting treatment of unusual or non-recurring transactions;
    - ascertaining compliance with covenants under loan agreements;
    - reviewing disclosure requirements for commitments and contingencies;
    - reviewing adjustments raised by the external auditor(s), whether or not included in the financial statements;
    - reviewing unresolved differences between management and the external auditor(s); and
    - obtain explanations of significant variances with comparative reporting periods.

4. The Audit Committee is to review the financial statements, prospectuses, MD&A, annual information forms 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 Audit 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 access the accuracy of those procedures.

5. With respect to the appointment of external auditor(s) by the Board, the Audit Committee shall:

    - recommend to the Board the external auditor(s) to be nominated;
    - recommend to the Board the terms of engagement of the external auditor(s), including the compensation of the auditor(s) and a confirmation that the external auditor (s) shall report directly to the Audit Committee;
    - on an annual basis, review and discuss with the external auditor(s) all significant relationships such auditor(s) have with the Harvest to determine the auditor(s)' independence;
    - when there is to be a change in auditor(s), review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
    - review and pre-approve any non-audit services to be provided to Harvest by the external auditor(s) and consider the impact on the independence of such auditor(s). The Audit Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member report to the Audit Committee at the next scheduled meeting such pre–approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

6. Review with external auditor(s) (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 Audit Committee shall also review annually with the external auditor(s) their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Harvest and its subsidiaries.

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

8. The Audit Committee shall establish a procedure for:

    - the receipt, retention and treatment of complaints received by Harvest regarding accounting, internal accounting controls or auditing matters; and
    - the confidential, anonymous submission by employees of Harvest of concerns regarding questionable accounting or auditing matters.

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

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

11. The Audit 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.

12. The Audit Committee shall review the Audit Committee mandate and subsequent revisions periodically, and recommend to the Board for approval.

MEETINGS AND ADMINISTRATIVE MATTERS

1. At all meetings of the Audit 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 Audit Committee, unless the Chair is not present, in which case the members of the Audit Committee present shall designate from among the members present the Chair for purposes of the meeting.

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

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

5. The Audit Committee shall meet with the external auditor(s) 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(s) and the Audit Committee consider appropriate.

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

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

8. At the discretion of the Audit Committee, the members of the Audit Committee shall meet in private session (in camera) with the external auditor(s), management and with Audit Committee members as required.

9. Following each meeting, the Audit Committee will report to the Board. Upon request, copies of the materials of such Audit Committee meeting should be provided at the next Board meeting after a meeting is held (these may still be in draft form).

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

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

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

13. 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 by the Audit Committee Chair.

See Item 6B “Compensation Committee and Corporate Governance Committee” in this annual report for a discussion of the compensation committee.

D. Employees

The number of full-time and part-time employees as at December 31 for each of the past three financial years was as follows:

	Upstream		**BlackGold**	**Downstream**	**Total**
	Corporate	***Field***			
2013	356	153	21	449	979
2012	350	154	15	468	987
2011	363	149	13	474	999

In the Downstream operations approximately 67% of the full-time employees and 100% of the part-time employees are unionized and represented by the United Steel Workers of America in four collective bargaining agreements. North Atlantic has had a history of good relations with its union, which is evidenced by the lack of any work stoppage at the Refinery. One of the collective bargaining agreements expires December 31, 2014, two collective agreements expire March 31, 2015 and one other collective agreement expired March 31, 2016.

E. Share Ownership

None of the individuals listed in Item 6B own shares of Harvest as 100% of the issued and outstanding shares of the Corporation are owned by KNOC.

ITEM 7. MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

A. Major Shareholders

KNOC owns 100% of the 386,078,649 issued and outstanding common shares of Harvest at December 31, 2013 (see Item 4.A of this annual report for more information on KNOC); this information remains unchanged as at the date of this annual report. KNOC is a leading international oil and gas exploration and production company wholly owned by the Government of Korea. The Trust Units of the predecessor company, Harvest Energy Trust, were widely held up until the date of the KNOC Acquisition on December 22, 2009.

B. Related Party Transactions

Other than as disclosed in Notes 12(c), 13 and 28 of the consolidated financial statements contained in Item 18 of this annual report, there have been no material related party transactions from the commencement of the 2013 fiscal year to the date of this annual report.

C. Interests of Experts

Not applicable.

ITEM 8. FINANCIAL INFORMATION

A. Consolidated Statements and Other Financial Information

FINANCIAL STATEMENTS

See Item 18 “Financial Statements” of this annual report for the audited consolidated financial statements. For information regarding the Corporation’s export sales, please see Item 4.B “Business Overview”.

LEGAL PROCEEDINGS

There are no legal proceedings which the Corporation or any subsidiary of the Corporation is or was a party to, or that any of their property is or was the subject of during the year ended December 31, 2013, nor are there any proceedings known to Harvest to be contemplated that involve a claim for damages exceeding ten per cent of Harvest's current assets.

There were no penalties or sanctions imposed against the Corporation or any subsidiary of the Corporation by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2013 or any other penalties or sanctions imposed by a court or regulatory body against the Corporation or any subsidiary of the Corporation that would likely be considered important to a reasonable investor in making an investment decision. No settlement agreements were entered into by the Corporation or any subsidiary of the Corporation with a court relating to securities legislation or with a securities regulatory authority during the year ended December 31, 2013.

DIVIDEND POLICY

The Corporation does not currently distribute dividends. See "Capital Resources" under Item 5 for discussion of limitations imposed on dividends by debt covenants.

B. Significant Changes

Except as otherwise disclosed in this annual report, there have been no material changes in our financial position, operations or cash flows since December 31, 2013.

ITEM 9. THE OFFER AND LISTING

Not applicable. The Corporation's shares are not traded on any exchanges or other regulated markets (only common shares have been issued and all of these are held by the Corporation's sole shareholder, KNOC).

ITEM 10. ADDITIONAL INFORMATION

A. Share Capital

Not applicable.

B. Memorandum and Articles of Association

Given that the information required under this Item 10B is primarily the listed matters as they are dealt with by or contained in a corporation's articles and bylaws, the following discussion is not, except to the extent applicable and specifically required under this Item (or as necessary for clarity) intended to compare the provisions of Harvest's bylaws and articles to the provisions of the ABCA. In some areas the Harvest bylaws and articles reflect or repeat the ABCA provisions, and in others, where and to the extent permitted by the ABCA, statutory provisions are added to or varied. Some description of the provisions of the ABCA may be made in the following explanations for context or for completeness to describe the relevant matters where the Articles or Bylaws do not have corresponding provisions. However, in any case where provisions of the ABCA are described, reference should be made to the actual statute for a complete understanding of the applicable law. In addition, in certain cases, the establishment of rights or restrictions under the Harvest articles and bylaws is subject to or restricted by the provisions of the ABCA, and the following does describe those aspects of the ABCA to the extent required for clear disclosure to meet the requirements of this Item 10B. The Harvest articles and bylaws have been developed to be in compliance with the ABCA requirements.

<u>REGISTRATION AND POWERS</u>

The Corporation is registered under Corporate Access Number 2015335496 and is the result of an amalgamation filed May 1, 2010 under the ABCA. The amalgamating corporations were KNOC Canada Ltd., Harvest Operations Corp. and 12065892 Alberta ULC. Companies incorporated or amalgamated under the ABCA have the capacity and, subject to the ABCA, the rights, powers and privileges of a natural person. Under the ABCA no bylaws are required to confer any particular power on a corporation or its directors, but if there are restrictions in its articles on the business carried on or exercised, the corporation shall not carry on or exercise such business. Harvest has no such restrictions in its articles of amalgamation ("Articles.").There are no stated objects or purposes as would be applicable in a memorandum of association jurisdiction. References to "Bylaws" in the following shall mean the bylaws of Harvest, Bylaw No.1 and Bylaw No. 2.

DIRECTORS

Material contracts: A director who is party to a material contract or proposed material contract (or material transaction) has to disclose the nature and extent of the director’s interest therein in accordance with the ABCA. Such director is unable to vote on any resolution to approve such contract except as permitted by the ABCA, but is not excluded in determining the quorum. Certain exceptions to the inability to vote are provided for under the ABCA, and in particular an exception is made for contracts relating primarily to the director’s remuneration as a director, officer, employee or agent of the Corporation or an affiliate. Accordingly, the directors do have power in the absence of an independent forum to vote directors’ compensation. The compensation of the directors is decided by the directors unless the board of directors requests approval of compensation from the shareholders, which would be required to be by ordinary resolution (passed by a majority of the votes cast by the shareholders who voted on the resolution, or signed by all the shareholders entitled to vote on that resolution.)

Borrowing powers: There are no limitations created either by the Bylaws or Articles on borrowing powers of Harvest exercisable by the directors.

Retirement or non- retirement: There are no provisions for retirement or non-retirement of directors under an age limit.

Qualifying number of shares: There are no requirements for director share ownership provided under the Articles and Bylaws.

CLASSES OF SHARES AND SHARE RIGHTS

The Articles provide for two classes of shares (common shares and preferred shares), and for the issuance of an unlimited number of common share and the issuance in series of preferred shares, in unlimited number

Common shares

Under the Articles the common shares have the right to vote at all meetings of shareholders, except meetings which have voting restricted to holders of a specified class of shares, and under the ABCA (a provision not varied by the Articles) each share entitles the holder to one vote at a meeting of shareholders. There is no provision under the Bylaws or Articles for directors to stand for reelection at staggered intervals or for cumulative voting. The common shares have the right to receive the remaining property and assets of the Corporation on dissolution, subject to the prior rights and privileges applicable to any other class of shares. With respect to the common shares under the Articles or Bylaws, there are no redemption provisions, sinking fund provisions, provisions imposing liability for further capital calls, or any provision discriminating against any existing or prospective holder of the common shares as a result of such shareholder owning a substantial number of shares.

Preferred shares

The preferred shares may be issued from time to time in one or more series with the number of shares in any such series determined by resolution of the directors prior to such issue. Under the Articles, each issued series of preferred shares shall have the rights, privileges, restrictions and conditions attaching to such series as are approved by resolution of the directors before the issue of such series.

Dividends

The common shares have the right to receive any dividend declared by Harvest subject to prior rights and privileges applicable to any other class of shares. The preferred shares’ rights to dividends may be established, as with any other rights, by resolution of directors as described above. Under the ABCA (and expressly included in the Bylaws) there is a solvency test and a liquidity test restricting the declaration and payment of dividends. There is no provision in the Articles or Bylaws for a lapse in dividend entitlement, based on time limits or otherwise.

Rights to change share rights

The necessary action to change the rights of holders of an Alberta corporation’s stock is set out under the ABCA. Under the ABCA in order to add, change or remove any rights, privileges, restrictions and conditions applicable to all or any of Harvest’s shares, the articles may be amended by special resolution. A special resolution is a resolution passed by a majority of not less than 2/3 of the votes cast by the shareholders who voted in respect of that resolution, or signed by all the shareholders entitled to vote on that resolution. The ability to amend or remove any of the foregoing includes rights to accrued dividends and can apply to shares whether issued or unissued. The Bylaws or Articles do not vary this provision of the ABCA and accordingly conditions for change of rights of Harvest shareholders are not more significant than required by law. Classes or series of shares are entitled to be dealt with in this regard by a vote separately by class or series, subject to the provisions of the ABCA. Articles of amendment must be filed after amendments are adopted by resolution.

MEETINGS

Annual meetings are provided under the Articles to be held in accordance with the requirements of the ABCA, and held at the registered office of the Corporation or elsewhere as determined by the directors. Special meetings may be called at any time and held on the dates and at the locations determined by the directors. Written notice to the shareholders is required (at least 21 days and not more than 50 days in advance of the meeting), including, if applicable details of special business to be transacted and the text of any special resolution to be tabled at the meeting. The notice is to be sent to each shareholder entitled to vote at the meeting, and the shareholders entitled to vote are those who on the record date are registered on the records of the Corporation (or if applicable, the transfer agent). Under the ABCA a written resolution signed by all shareholders entitled to vote on it is as valid as though passed at a meeting and such a resolution satisfies statutory meeting requirements. Accordingly in the case of a sole shareholder corporation, such as Harvest it can be practical to address annual meeting requirements and to deal with the business to be transacted at the annual meeting by written resolutions.

SHARE (SECURITIES) OWNERSHIP

The number of direct or indirect beneficial owners of securities of the Corporation under the Articles is limited to not more than fifty (securities in this context does not include non-convertible debt securities) and any invitation to the public to subscribe for securities is prohibited. With respect to the rights to acquire securities, the Articles provide that directors' approval is required to transfer securities to a person who is not already a security holder. There are no limitations under the Articles and Bylaws on the rights of non-resident shareholders to hold securities or to exercise voting rights on securities which are held nor are there any such limitations pursuant to provisions of the ABCA.

OTHER PROVISIONS

There are no provisions of the Articles or Bylaws that would have the effect of delaying, deferring or preventing a change in control of Harvest and that would operate only with respect to a merger, acquisition or corporate restructuring involving Harvest or any subsidiaries. There are no provisions in the Bylaws governing the ownership threshold above which shareholder ownership must be disclosed. There are no provisions in the Articles or Bylaws governing changes in capital, and accordingly no conditions on changes in capital of Harvest under the Articles or Bylaws.

C. Material Contracts

21/8% SENIOR NOTES

The following is a summary of the material attributes and characteristics of the 21/8% Senior Notes:

The 21/8% Senior Notes were issued on May 14, 2013 and mature on May 14, 2018. Interest on the 21/8% Senior Notes is paid semi-annually in arrears on May 14 and November 14 of each year. The 21/8% Senior Notes are unsecured senior obligations of the Corporation and rank equally with its existing and future unsecured senior indebtedness. KNOC have fully, unconditionally and irrevocably guaranteed the 21/8% Senior Notes. The notes are not redeemable prior to maturity except upon the occurrence of certain events related to tax law. Upon the occurrence of a change in control, each holder of the 21/8% Senior Notes will have the right to require the Corporation to redeem all or any part of such holder's 21/8% Senior Notes at a redemption price equal to 100% of the principal amount thereof plus accrued and unpaid interest. The 21/8% Senior Notes are listed on the Singapore Exchange.

67/8% SENIOR NOTES AND THE NOTE INDENTURE

The following is a summary of the material attributes and characteristics of the Note Indenture (and references below to "Notes" refer to the 67/8% Senior Notes):

PAYMENT UPON REDEMPTION

The Notes mature on October 1, 2017. Prior to maturity, the Notes are redeemable at a redemption price equal to 100% of the principal amount of the Notes being redeemed plus a make-whole redemption premium and accrued and unpaid interest to the redemption date. Harvest may also redeem the Notes at any time in the event that certain changes affecting Canadian withholding taxes occur.

COVENANTS

There are 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 in the Note Indenture, of less than 2.0 to 1. In addition to debt permitted under the interest coverage ratio limitation, the incurrence of additional indebtedness may be permitted under other incurrence tests or baskets. One provision allows Harvest's incurrence of indebtedness under the Credit Facility or other future bank debt in an aggregate principal amount not to exceed the greater of $1.0 billion and 15% of total assets. In addition, the covenants under the Note Indenture limit the amount of restricted payments, including dividends to Harvest's shareholders. REGISTRATION

On August 1, 2012 the Corporation completed the exchange of its initial unregistered Notes for Notes that have been registered under the Securities Act, as amended.

CREDIT FACILITY

The Credit Facility is a secured covenant-based $1 billion revolving credit facility with a syndicate of eleven financial institutions. The facility is secured by a first floating charge over all of the assets of Harvest (including Harvest's ownership interest in non-wholly owned partnerships) and its wholly-owned restricted subsidiaries plus a first mortgage security interest on the Downstream operation's refinery assets.

Harvest pays a floating interest rate plus a margin that changes based on the ratio of the Corporation's Senior Debt, as defined in the Credit Facility's agreement (see details below) to Annualized EBITDA (Annualized EBITDA as more fully discussed below and as defined in "Non-GAAP Measures" in this annual report). As at December 31, 2013, $788.5 million was drawn on the Credit Facility plus $13.3 million of letters of credit.

In addition to the standard representations, warrants and covenants commonly contained in a credit facility, the Credit Facility agreement contained the following covenants, among others:

(a) An aggregate limitation of $25 million on financial assistance and/or capital contributions to parties other than those included in the first floating security interest;

(b) A limitation on carrying on business in countries that are not members of the Organization for Economic Cooperation and Development;

(c) A limitation on the payment of distributions to shareholders except for permitted distributions. The basis for permitted distributions include allowed distributions based on the Total Debt to Annualized EBITDA ratio not exceeding 2.5:1 after any such distribution, and allowed aggregate distributions for the most recent fiscal quarters (including the amount of the proposed distribution) in amounts less than Annualized EBITDA minus capital expenditures during the most recent four fiscal quarters by Harvest and its restricted subsidiaries. As well there is a provision for other allowed distributions provided that the aggregate of distributions made thereunder since April 29, 2011 is not to exceed $150 million; this basis for distribution is further subject to compliance with certain ratios after cumulative distributions of $100 million; and

(d) Financial compliance covenants are as follows (compliance is certified quarterly for the relevant quarter or the fiscal year, as applicable):

    (1) Effective April 1, 2013[(1)]: Annualized EBITDA to Interest Expense of 2.50 to 1.0 or greater;
    (2) Senior Debt[(2)] to Annualized EBITDA of 3.0 to 1.0 or less;
    (3) Senior Debt[(2)] to Capitalization of 50% or less; and
    (4) Total Debt to Capitalization of 55% or less.

[(1)]The Annualized EBITDA to Interest expense ratio was added effective April 1, 2013, under an amendment to the Credit Facility agreement and the Total Debt to Annualized EBITDA ratio was removed pursuant to the amendment.

(2) Prior to the April 15, 2014 amendments to the Credit Facility agreement, "Senior Debt" included letters of credit, drawdowns from the Credit Facility, risk management contract and guarantees and "Total Debt" consisting of Senior Debt, the 67/8% Senior Notes, the 21/8% Senior Notes and the Debentures. "Senior Debt" and "Total Debt" definitions have been amended on April 15, 2014, see below for details.

For purposes of determining the financial covenants, the following terms are defined in the Credit Facility agreement:

(b) Annualized EBITDA[3] is the aggregate of the past four quarters Net Earnings plus:

(1) interest and financing charges;
(2) future income tax expense;
(3) depletion, depreciation and amortization;
(4) unrealized gains/losses on risk management contracts;
(5) unrealized currency exchange gains/losses; and
(6) other non-cash items.

(3) "Annualized EBITDA" has been amended on April 15, 2014, see below for details.

(c) Capitalization[4] is the aggregate of the amounts of Total Debt, Related Party Loans and shareholders' equity, all as reported in Harvest's consolidated balance sheet in accordance with IFRS, less equity for the BlackGold project.

(4) "Capitalization" has been amended on April 15, 2014, see below for details.

(d) Interest Expense includes capitalized interest.

With respect to these financial covenants, Harvest's December 31, 2013 financial ratios were as follows:

- Senior Debt to Annualized EBITDA of 2.41 to 1.0;
- Annualized EBITDA to annualized interest expense of 3.62 to 1.0;
- Senior Debt to Capitalization of 22%; and
- Total Debt to Capitalization of 54%.

On April 15, 2014, Harvest amended its Credit Facility to accommodate the progression of non-wholly owned partnership and joint venture arrangements for the development of Company lands:

(a) The amendments included provisions that allow the formation, operation and funding of partnerships that Harvest does not fully own, within specific parameters regarding the amount of assets and production contributed to such non- wholly owned partnership and joint venture arrangements;

(b) Limitation on distribution has been amended to allow distributions to Harvest or third parties by a joint venture partnership under specific provisions;

(c) "Annualized EBITDA", "Total Debt" and "Senior Debt" have been amended to accommodate the partnership and joint venture arrangements. The followings are items that have been added to the definitions described above:

- Annualized EBITDA includes non-designated cash distributions from non-wholly owned joint ventures and partnerships, but excludes earnings from such entities;

- Senior Debt includes any outstanding loan made by a non-wholly owned or partnership to Harvest, but excludes the aggregate redemption price payable by the Deep Basin Partnership to KERR if KERR elects to require a redemption of its ownership interest in the Deep Basin Partnership pursuant to the Deep Basin Partnership Agreement ("Deep Basin Redemption Price); and

- Total Debt includes the Deep Basin Redemption Price net of certain adjustments; and

(d) In addition, the amendment removed Harvest's option to cause the BlackGold assets to be removed from the security package of the Credit Facility, effectively enabling the Company to recognize equity related to BlackGold of $457.7 million as at December 31, 2013 for purposes of Total Capitalization, and specified an incremental amount of $229.5 million to be added to Total Capitalization representing partial relief of the Downstream impairment charge incurred in 2013, effective Q1 2014.

SUPPLY AND OFFTAKE AGREEMENT
SOA (2011)

North Atlantic entered into the SOA (2011) on October 11, 2011 upon the termination of the SOA. The SOA (2011) provides that the ownership of substantially all crude oil and other feedstocks and refined product inventories at the Refinery be retained by MEC and that MEC be granted the exclusive right and obligation to provide crude oil feedstock and other feedstocks for delivery to the Refinery as well as the exclusive right and obligation to purchase virtually all refined products produced by the Refinery for export. The SOA (2011) also provides that MEC will receive a time value of money ("TVM") amount associated with the purchase of crude oil and other feedstocks and sale of refined products as the SOA (2011) requires that MEC 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 (2011) provides North Atlantic with the opportunity to share the incremental profits and losses resulting from the sale of products beyond the U.S. east coast markets.

Pursuant to the SOA (2011), North Atlantic, in consultation with MEC, requests a certain slate of crude oil and other feedstocks and MEC is obligated to provide the feedstocks in accordance with the request and the other provisions of the SOA (2011). The SOA (2011) includes a feedstock transfer pricing formula that aggregates the pricing 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. The purpose of these operational price risk management contracts is to convert the fixed price of crude oil and other feedstock purchases to floating prices for the period from the purchase date through to the date the refined products are sold to North Atlantic to allow "matching" of feedstock purchases to refined product sales.

The SOA (2011) requires that MEC 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 price based on the current Boston and New York City markets, less the costs of transportation, insurance, port fees, inspection charges and similar costs incurred by MEC, plus the TVM component.

The SOA (2011) is a successive one-year term agreement with an initial one-year term and may be terminated by either party 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 arm's length transaction, upon 30 days notice prior to the desired termination date. Further, the SOA (2011) 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. Upon termination of the agreement or the right and obligation to provide feedstocks, North Atlantic has the option to purchase or arrange for another feedstock supplier to purchase the feedstocks and refined product inventories in designated tanks at the prevailing prices as stipulated under the SOA (2011).

On April 19, 2012 and subsequently on July 23, 2012 the SOA (2011) was amended to allow the Refinery to purchase from MEC certain additional petroleum products, additives and feedstock that was not previously included in the SOA (2011), to permit delivery method of feedstock and feedstock additives in addition to ex-ship delivery and to amend the Annex B "Designated Tank".

D. Exchange Controls

There are no governmental laws, decrees, regulations or legislation of Canada or restrictions under the constating documents of Harvest that affect the import or export of capital or the remittance of dividends, interest or other payments to non-resident security holders.

E. Taxation

Not applicable.

F. Dividends and Paying Agents

Not applicable.

G. Statements by Experts

Not applicable.

H. Documents on Display

Documents concerning the Corporation which are referred to in this annual report may be inspected at Harvest's head office, Suite 2100, 330 - 5th Avenue S.W., Calgary, Alberta T2P 0L4. In addition, all of the SEC filings made electronically by Harvest are available to the public on the SEC website at www.sec.gov.

I. Subsidiary Information

Not applicable.

ITEM 11. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Quantitative and qualitative disclosures of market risk as at December 31, 2013 can be found in Note 16 of the Corporation's December 31, 2013 consolidated financial statements included under Item 18 of this annual report. All market risk sensitive instruments are entered into for purposes other than trading.

ITEM 12. DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

Not applicable.

ITEM 13. DEFAULTS, DIVIDEND ARREARAGES AND DELINQUENCIES

Not applicable.

ITEM 14. MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

Not applicable.

ITEM 15. CONTROLS AND PROCEDURES DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision of the Chief Executive Officer and Chief Financial Officer, the Corporation has evaluated the effectiveness of its disclosure controls and procedures as of December 31, 2013 as defined under the rules adopted by the U.S. Securities and Exchange Commission. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2013, the disclosure controls and procedures were effective to ensure that information required to be disclosed by Harvest in reports it files or submits to U.S. securities authorities was recorded, processed, summarized and reported within the time period specified in U.S. securities laws and was accumulated and communicated to management, including its Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining internal control over our financial reporting. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes. Management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2013. The evaluation was based on the Internal Control – Integrated Framework (2013) issued by the Audit Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2013.

Because of its 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 how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control systems are met.

CHANGES IN CONTROL OVER FINANCIAL REPORTING

There were not any significant changes in internal controls over financial reporting for the period ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 16A. AUDIT COMMITTEE FINANCIAL EXPERT

Harvest's board of directors has determined Messrs. Randall Henderson, Allan Buchignani and Richard Kines are audit committee financial experts as defined in Item 16A of Form 20-F. Messrs. Henderson, Buchignani and Kines, members of the board of directors of Harvest, are independent, within the meaning of the definition of audit committee member independence applicable under the Corporate Governance Standards of the New York Stock Exchange. Refer to Item 6.A for additional information on their relevant education and experience.

ITEM 16B. CODE OF ETHICS

Harvest has adopted a Code of Ethics 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, Chief Financial Officer, and Chief Operating Officer. The Code of Ethics can be found on Harvest's Corporate Governance website at http://www.harvestenergy.ca/corporate-overview/corporate-governance.html. There were no waivers or amendments to the Code of Ethics in 2013.

ITEM 16C. PRINCIPAL ACCOUNTANT FEES AND SERVICES

On October 15, 2013, KPMG LLP Chartered Accountants ("KPMG") was appointed to be the auditor of Harvest for the fiscal year ended December 31, 2013. Prior to October 15, 2013, Ernst & Young LLP, Chartered Accountants ("EY") was the auditor of the Corporation for the fiscal year 2011 and 2012. For more information, please see section "Change in Registrant's Certifying Accountant" under Item 16F of this annual report.

The aggregate fees billed by Harvest's external auditor in the last two fiscal years for audit services are as follows:

For the year ended December 31	**KPMG[1]) 2013**	**EY[2]) 2013**	**Total 2013**	EY 2012
Audit Fees[3]	**600,000**	**97,000**	**697,000**	682,000
Audit-Related Fees[4]	**47,000**	**180,375**	**227,375**	105,000
Tax Fees[5]	**319,501**	**127,224**	**446,725**	54,225
Executive Compensation – Related Fees[6]	**-**	**-**	**-**	41,074
All Other Fees[7]	**11,611**	**26,285**	**37,896**	3,395
Total	**978,112**	**430,884**	**1,408,996**	885,694

(1) Includes fees billed by KPMG for the fiscal year ended December 31, 2013 beginning after the appointment of KPMG on October 15, 2013.

(2) Includes fees billed by EY during 2013 for the fiscal year ended December 31, 2012 and December 31, 2013 up to the appointment of KPMG on October 15, 2013.

(3) Represents the aggregate fees of the Corporation's auditors for audit services in respect of the financial year and $97,000 relating to the fiscal year ended December 31, 2012.

(4) Represents the aggregate fees billed for assurance and related services by the Corporation's auditors that are related to the performance of audit or review of the Corporation's financial statements and are not included under "Audit Fees" and are primarily composed of services related to the Corporation's interim financial statements.

(5) Represents the aggregate fees billed for tax compliance, tax advice and tax planning in respect of the financial year.

(6) Represents the aggregate fee billed for the reviewing of Harvest's long term incentive program during the financial year.

(7) Represents the EY online subscription and the assessment fee billed by The Canadian Public Accountability Board ("CPAB") per the National Instrument 52-108 Auditor Oversight mandate for reporting issuers to have an audit completed by a CPAB participant firm.

The Audit Committee must first approve all non-audit or special services performed by any independent accountants. All remuneration provided to the Corporation's auditor and any independent accountants are also approved by the Audit Committee. The Corporation'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. The Audit Committee approved all services included in the table above. See Item 6.C "Board Practice" for Harvest's pre-approval process.

ITEM 16D. EXEMPTIONS FROM THE LISTING STANDARDS FOR AUDIT COMMITTEES

Not applicable.

ITEM 16E. PURCHASE OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PURCHASERS

Not applicable.

ITEM 16F. CHANGE IN REGISTRANT'S CERTIFYING ACCOUNTANT

EY resigned as auditor of the Corporation on October 15, 2013. KPMG was appointed as the auditor of the corporation on October 15, 2013 to fill the vacancy resulting from the former auditor's resignation. The resignation of EY and the appointment of KPMG were considered and approved by the audit committee of the board of directors of the Corporation and approved by the board of directors of the Corporation.

EY did not express any reservations in its audit reports with respect to consolidated financial statements of Harvest Operations Corp. for the 2012 or 2011 fiscal years and such reports did not contain an adverse opinion or a disclaimer of opinion, and were not qualified or modified as to uncertainty, audit scope, or accounting principles. During the 2012 or 2011 fiscal years, or the subsequent interim period prior to the resignation of EY (January 1, 2013 to October 15, 2013), there were no disagreements with EY on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreement(s), if not resolved to EY's satisfaction, would have caused EY to make reference to the subject matter of the disagreement(s) in connection with its reports, and there were no reportable events that occurred within the 2012 or 2011 fiscal years or the subsequent interim period prior to the resignation of EY (January 1, 2013 to October 15, 2013).

ITEM 16G. CORPORATE GOVERNANCE

Not applicable.

ITEM 16H. MINE SAFETY DISCLOSURE

Not applicable.

ITEM 17. FINANCIAL STATEMENTS

Not applicable.

ITEM 18. FINANCIAL STATEMENTS

See F-pages following Item 19.

ITEM 19. EXHIBITS

1	Harvest's Articles of Amalgamation and Bylaws[9]
2.1	67/8% Senior Notes Indenture, dated October 4, 2010[1]
2.2	21/8% Senior Notes Fiscal Agency Agreement, dated May 14, 2013[11]
4.1	Supply and Offtake Agreement between North Atlantic and Macquarie Energy Canada Ltd. dated October 1, 2011[3] and First Amendment to Supply and Offtake Agreement between North Atlantic and Macquarie Energy Canada Ltd dated December 19, 2011[2]
4.2	Second and Third Amendments to Supply and Offtake Agreement between North Atlantic and Macquarie Energy Canada Ltd dated April 19, 2012 and July 23, 2012 respectively[3]
4.3	Amended and Restated Credit Facility dated April 30, 2010[4]
4.4	First Amending Agreement (Credit Facility) dated December 17, 2010[1]
4.5	Second Amending Agreement (Credit Facility) dated April 29, 2011[1]
4.6	Third Amending Agreement (Credit Facility) dated December 16, 2011[5]
4.7	Fourth Amending Agreement (Credit Facility) dated June 29, 2012[6]
4.8	Fifth Amending Agreement (Credit Facility) dated July 31, 2012[7]
4.9	Sixth Amending Agreement (Credit Facility) dated March 12, 2013[8]
4.10	Seventh Amending Agreement (Credit Facility) dated October 18, 2013[10]
4.11	Amended and Restated Credit Agreement (Credit Facility) dated April 15, 2014[12]
4.12	67/8% Senior Notes Indenture, dated October 4, 2010[1]
4.13	Harvest's Articles of Amalgamation and Bylaws incorporated by reference to Item 19.1 of this annual report.
8	Refer to Item 4C “Organization Structure” of this annual report.
12.1	Chief Executive Officer Certification required by Rule 13a-14(a) or 15d-14(a)
12.2	Chief Financial Officer Certification required by Rule 13a-14(a) or 15d-14(a)
13.1	Chief Executive Officer Certification required by Rule 13a-14(b) or 15d-14(b)
13.2	Chief Financial Officer Certification required by Rule 13a-14(b) or 15d-14(b)
15.1	GLJ’s consent and Reserve Evaluation Procedure Report covering letter
15.2	EY response to Item 16F

(1) Incorporated by reference to Form 6-K filed on June 20, 2011.

(2) Incorporated by reference to Form 6-K filed on April 16, 2012.

(3) Incorporated by reference to Form 6-K filed on July 30, 2012.

(4) Incorporated by reference to Form 6-K filed on May 17, 2010.

(5) Incorporated by reference to Form 6-K filed on April 2, 2012.

(6) Incorporated by reference to Form 6-K filed on July 3, 2012.

(7) Incorporated by reference to Form 6-K filed on July 31, 2012.

(8) Incorporated by reference to Form 6-K filed on March 19, 2013

(9) Incorporate by reference to Form 20-f filed on April 30, 2013

(10) Incorporated by reference to Form 6-K filed on November 18, 2013

(11) Incorporated by reference to Form 6-K filed on March 12, 2014

(12) Incorporated by reference to Form 6-K filed on April 24, 2014

SIGNATURES

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

Harvest Operations Corp.

/s/ Chang-Koo Kang
Chang-Koo Kang
Chief Financial Officer

Dated: April 30, 2014

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HARVEST OPERATIONS CORP. – AUDITED CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT

In management's opinion, the accompanying consolidated financial statements of Harvest Operations Corp. (the "Company") have been prepared within reasonable limits of materiality and in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). 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 6, 2014. Management is responsible for the consistency, therewith, of all other financial and operating data presented in Management's Discussion and Analysis for the year ended December 31, 2013.

To meet our responsibility for reliable and accurate financial statements, management has developed and maintains internal controls, 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 (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. We have concluded that as of December 31, 2013, 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 have been examined in 2013 by our auditors, KPMG LLP and in 2012 and 2011 by Ernst & Young LLP. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements prepared in accordance with IFRS as issued by the IASB. The Auditors' Report outlines the scope of their examination and sets forth their opinion on our consolidated financial statements.

The Board of Directors is responsible for approving the consolidated financial statements. The Board fulfills its responsibilities related to financial reporting mainly through the Audit Committee. The Audit Committee consists exclusively of independent directors, including at least one director with financial expertise. The Audit Committee meets regularly with management and the external auditors to discuss reporting and governance issues and ensures each party is discharging its responsibilities. The Audit Committee has reviewed these financial statements with management and the auditors and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Company.

(Signed)

Myunghuhn Yi
President and Chief Executive Officer

(Signed)

Chang-Koo Kang
Chief Financial Officer

Calgary, Alberta
March 6, 2014

KPMG

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholder and Directors of Harvest Operations Corporation

We have audited the accompanying consolidated financial statements of Harvest Operations Corporation, which comprise the consolidated statements of financial position as at December 31, 2013 and the consolidated statements of comprehensive loss, changes in shareholder's equity and cash flows for the year ended December 31, 2013, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Harvest Operations Corporation as at December 31, 2013 and its consolidated financial performance and its consolidated cash flows for the year ended December 31, 2013 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Comparative Information

Without modifying our opinion, we draw attention to Notes 2 and 3 to the consolidated financial statements which indicates that the comparative information presented as at and for the year ended December 31, 2012 and 2011, has been restated and that the comparative information presented as at January 1, 2012, has been derived from the consolidated financial statements as at and for the year ended December 31, 2011.

The consolidated financial statements of Harvest Operations Corp. as at and for the years ended December 31, 2012, and December 31, 2011, (from which the statement of financial position as January 1, 2012, has been derived), excluding the restatements described in Notes 2 and 3 to the consolidated financial statements, were audited by another auditor who expressed an unmodified opinion on those financial statements on February 28, 2013.

As part of our audit of the consolidated financial statements as at and for the year ended December 31, 2013, we audited the restatements described in Notes 2 and 3 to the consolidated financial statements that was applied to restate the comparative information presented as at and for the year ended December 31, 2012 and as at January 1, 2012, (derived from the consolidated financial statements as at and for the year ended December 31, 2011). In our opinion, the restatements are appropriate and have been properly applied.

We were not engaged to audit, review, or apply any procedures to the December 31, 2012, consolidated financial statements, the December 31, 2011, consolidated financial statements (not presented herein) or the January 1, 2012, consolidated statement of financial position, other than with respect to the restatements described in Notes 2 and 3 to the consolidated financial statements. Accordingly, we do not express an opinion or any other form of assurance on those financial statements taken as a whole.

KPMG LLP

Chartered Accountants

March 6, 2014
Calgary, Canada

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Directors and the Shareholder of Harvest Operations Corp.:

We have audited the accompanying consolidated financial statements of Harvest Operations Corp., which comprise of the consolidated statement of financial position as at December 31, 2012 and 2011, and the consolidated statements of comprehensive loss, statement of changes in shareholder's equity and cash flow statement for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Harvest Operations Corp. as at December 31, 2012 and 2011 and of its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board

Other matter

The consolidated financial statements of Harvest Operations Corp. for the year ended December 31, 2010, were audited by another auditor who expressed an unmodified opinion on those statements on June 14, 2012.

Ernst + Young LLP

Chartered Accountants
Calgary, Canada

February 28, 2013

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As At *(millions of Canadian dollars)*	Notes		**December 31, 2013**		December 31, 2012 *(Restated)**		January 1, 2012 *(Restated)**
Assets							
Current assets							
Cash	16	**$**	–	$	7.6	$	6.6
Accounts receivable	16		**168.9**		175.6		212.3
Inventories	27		**51.6**		80.8		61.0
Prepaid expenses			**14.1**		20.2		18.5
Risk management contracts	16		**0.3**		1.8		20.2
Asset held for sale	8		–		16.9		–
			234.9		302.9		318.6
Non-current assets							
Long-term deposit			**5.0**		5.0		24.9
Investment tax credits and other	19		**0.6**		28.5		54.0
Deferred income tax asset	19		**148.8**		61.1		–
Exploration and evaluation assets	11		**59.4**		73.4		74.5
Property, plant and equipment	9		**4,461.4**		4,791.9		5,407.5
Goodwill	10		**379.8**		391.8		404.9
			5,055.0		5,351.7		5,965.8
Total assets		**$**	**5,289.9**	$	5,654.6	$	6,284.4
Liabilities							
Current liabilities							
Accounts payable and accrued liabilities	16	**$**	**258.3**	$	373.0	$	462.2
Current portion of long-term debt	12,16		**12.3**		331.8		107.1
Current portion of provisions	17		**39.1**		28.1		17.1
Risk management contracts	16		**0.6**		–		–
Liabilities associated with assets held for sale	8		–		11.9		–
			310.3		744.8		586.4
Non-current liabilities							
Long-term debt	12,16		**1,973.0**		1,277.9		1,486.2
Related party loans	16,28		**259.6**		172.1		–
Long-term liability	16,18		**69.5**		8.2		2.7
Non-current provisions	17		**731.5**		727.3		674.5
Post-employment benefit obligations	26		**6.8**		32.4		26.0
Deferred income tax liability	19		–		–		54.9
			3,040.4		2,217.9		2,244.3
Total liabilities		**$**	**3,350.7**	$	2,962.7	$	2,830.7
Shareholder's equity							
Shareholder's capital	14		**3,860.8**		3,860.8		3,860.8
Contributed surplus	28		**4.3**		–		–
Deficit			**(1,893.2)**		(1,111.3)		(390.3)
Accumulated other comprehensive loss	25		**(32.7)**		(57.6)		(16.8)
Total shareholder's equity			**1,939.2**		2,691.9		3,453.7
Total liabilities and shareholder's equity		**$**	**5,289.9**	$	5,654.6	$	6,284.4

*See Note 3
Commitments *[Note 29]*
The accompanying notes are an integral part of these consolidated financial statements.

On behalf of the Board of Directors: (Signed) Randall Henderson, Director — (Signed) Allan Buchignani, Director

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

For the years ended December 31,

(millions of Canadian dollars)	Notes	2013	2012 *(Restated)**	2011 *(Restated)**
Petroleum, natural gas, and refined products sales		**$ 5,518.6**	$ 5,945.6	$ 4,589.2
Royalties		**(153.9)**	(164.6)	(195.5)
Revenues	20	**5,364.7**	5,781.0	4,393.7
Expenses				
Purchased products for processing and resale	27	**4,327.4**	4,520.3	3,118.1
Operating	21	**578.7**	621.6	577.0
Transportation and marketing		**28.0**	26.6	35.9
General and administrative	21	**68.7**	65.6	62.6
Depletion, depreciation and amortization	9	**612.8**	688.4	626.7
Exploration and evaluation	11	**12.3**	24.9	18.3
Gains on disposition of property, plant and equipment	8,9	**(34.1)**	(30.3)	(7.9)
Finance costs	22	**94.2**	111.0	109.1
Risk management contracts gains	16	**(4.4)**	(0.5)	(6.7)
Foreign exchange (gains) losses	23	**44.2**	(1.3)	(4.0)
Impairment on property, plant and equipment	9	**483.0**	557.3	–
Loss before income tax		**(846.1)**	(802.6)	(135.4)
Income tax recovery	19	**(64.2)**	(81.6)	(30.0)
Net loss		**$ (781.9)**	$ (721.0)	$ (105.4)
Other comprehensive loss ("OCL")				
Items that may be reclassified to net income				
(Losses) gains on designated cash flow hedges, net of tax	16,25	**(1.1)**	(13.2)	19.4
Gains (losses) on foreign currency translation	25	**7.9**	(17.7)	21.5
Items that will not be reclassified to net income				
Actuarial gains (losses), net of tax	25,26	**18.1**	(9.9)	(4.2)
Comprehensive loss		**$ (757.0)**	$ (761.8)	$ (68.7)

*See Note 3

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

(millions of Canadian dollars)	Notes	Shareholder's Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Loss	Total Shareholder's Equity
Balance at December 31, 2012 (*Restated*)*		$ 3,860.8	$ –	$ (1,111.3)	$ (57.6)	$ 2,691.9
Losses on derivatives designated as cash flow hedges, net of tax	25	–	–	–	(1.1)	(1.1)
Gains on foreign currency translation	25	–	–	–	7.9	7.9
Actuarial gains, net of tax	25	–	–	–	18.1	18.1
Shareholder loan	28	–	4.3	–	–	4.3
Net loss		–	–	(781.9)	–	(781.9)
Balance at December 31, 2013		**$ 3,860.8**	**$ 4.3**	**$ (1,893.2)**	**$ (32.7)**	**$ 1,939.2**
Balance at December 31, 2011 (*Restated*)*		$ 3,860.8	$ –	$ (390.3)	$ (16.8)	$ 3,453.7
Losses on derivatives designated as cash flow hedges, net of tax	25	–	–	–	(13.2)	(13.2)
Losses on foreign currency translation	25	–	–	–	(17.7)	(17.7)
Actuarial losses, net of tax	25	–	–	–	(9.9)	(9.9)
Net loss		–	–	(721.0)	–	(721.0)
Balance at December 31, 2012 (*Restated*)*		$ 3,860.8	$ –	$ (1,111.3)	$ (57.6)	$ 2,691.9
Balance at January 1, 2011 (*Restated*)*		$ 3,355.4	$ –	$ (284.9)	$ (53.5)	$ 3,107.0
Issued for cash	7	505.4	–			505.4
Gains on derivatives designated as cash flow hedges, net of tax	25	–	–	–	19.4	19.4
Gains on foreign currency translation	25	–	–	–	21.5	21.5
Actuarial losses, net of tax	25	–	–	–	(4.2)	(4.2)
Net loss		–	–	(105.4)	–	(105.4)
Balance at December 31, 2011 (*Restated*)*		$ 3,860.8	$ –	$ (390.3)	$ (16.8)	$ 3,453.7

*See Note 3

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars)	Notes	2013	2012 (Restated)*	2011 (Restated)*
		Year Ended December 31		
Cash provided by (used in) Operating Activities				
Net loss		**$ (781.9)**	$ (721.0)	$ (105.4)
Items not requiring cash				
Depletion, depreciation and amortization		**612.8**	688.4	626.7
Accretion of decommissioning and environmental remediation liabilities	17,22	**22.3**	20.7	23.6
Unrealized (gains) losses on risk management contracts	16	**0.5**	1.1	(0.7)
Unrealized (gains) losses on foreign exchange	23	**40.8**	(1.2)	2.6
Unsuccessful exploration and evaluation costs	11	**11.5**	22.0	17.8
Impairment on property, plant and equipment	9	**483.0**	557.3	–
Gains on disposition of property, plant and equipment	9	**(34.1)**	(30.3)	(7.9)
Gains on redemption of convertible debentures	12,22	**(3.6)**	(0.1)	–
Deferred income tax recovery	19	**(64.2)**	(81.6)	(30.1)
Other non-cash items		**2.4**	(3.1)	4.9
Realized foreign exchange loss on Senior Unsecured Credit Facility	13	**1.3**	–	–
Settlement of decommissioning and environmental remediation liabilities	17	**(19.6)**	(20.4)	(22.1)
Change in non-cash working capital	24	**(70.6)**	11.0	51.1
		$ 200.6	$ 442.8	$ 560.5
Financing Activities				
Issuance of common shares, net of issuance costs	7,14	–	–	505.4
Bank borrowing, net	12	**293.8**	135.1	343.3
Borrowings from related party loans	28	**80.0**	168.0	–
Borrowing on Senior Unsecured Credit Facility	13	**395.4**	–	–
Repayment of Senior Unsecured Credit Facility	13	**(396.7)**	–	–
Repayment of promissory note	12	**(11.9)**	–	–
Issuance of senior notes, net of issuance costs	12	**634.4**	–	–
Redemption of convertible debentures	12	**(627.2)**	(106.8)	–
Other cash items		–	(0.3)	–
		$ 367.8	$ 196.0	$ 848.7
Investing Activities				
Additions to property, plant and equipment	9	**(741.4)**	(620.1)	(974.1)
Additions to exploration and evaluation assets	11	**(16.7)**	(41.1)	(50.9)
Business acquisitions	7	–	–	(509.8)
Property dispositions, net	8,9	**160.5**	87.2	4.5
Change in non-cash working capital	24	**21.6**	(63.8)	108.7
		$ (576.0)	$ (637.8)	$ (1,421.6)
Change in cash		**(7.6)**	1.0	(12.4)
Effect of exchange rate changes		–	–	0.1
Cash, beginning of period		**7.6**	6.6	18.9
Cash, end of period		$ –	$ 7.6	$ 6.6
Interest paid		**$ 78.4**	$ 83.9	$ 75.9
Income taxes paid		$ –	$ –	$ 0.1

*See Note 3
The accompanying notes are an integral part of these consolidated financial statements.

1. Nature of Operations and Structure of the Company

Harvest Operations Corp. ("Harvest" or the "Company") is an energy company in the business of the exploration, development, and production of crude oil, bitumen, natural gas and natural gas liquids in western Canada with a petroleum refining and marketing business located in the Province of Newfoundland and Labrador. Harvest has three reportable segments: Upstream, BlackGold oil sands ("BlackGold") and Downstream. For further information regarding these reportable segments, see note 6.

Harvest is a wholly owned subsidiary of Korea National Oil Corporation ("KNOC"). The Company is incorporated and domiciled in Canada. Harvest's principal place of business is located at 2100, 330 – 5th Avenue SW, Calgary, Alberta, Canada T2P 0L4.

2. Basis of Presentation

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). Comparative information in respect of the previous period is provided.

These consolidated financial statements were approved and authorized for issue by the Board of Directors on March 6, 2014.

The comparative consolidated financial statements have been reclassified from statements previously presented to conform to the presentation of the current year consolidated financial statements as follows:

- As at December 31, 2013, Harvest reclassified the property, plant and equipment balance to include other long-term assets. Comparative amounts in the statement of financial position were restated. As a result, $8.6 million was reclassified from "other long-term assets" to "property, plant and equipment" as at December 31, 2012 (January 1, 2012 - $7.1 million). The reclassifications had no impact to "total assets".

- In addition, to conform to the 2013 presentation of the write-down of investment tax credits ("ITCs") which has been included in income tax recovery, Harvest reclassified the write-down of the ITCs from the year ended December 31, 2012 of $27.7 million from "impairment on property, plant and equipment" to "income tax recovery". The reclassification had no impact to "net loss".

In addition, Harvest presents an additional statement of financial position at the beginning of the earliest period presented when there is a retroactive application of an accounting policy that has a material impact to the Company. Please also refer to note 3a for the effects of the application of IAS 19R on the comparative periods.

Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for held-for-trading financial assets and derivative financial instruments, which are measured at fair value.

Functional and Presentation Currency

In these consolidated financial statements, unless otherwise indicated, all dollar amounts are expressed in Canadian dollars, which is the Company's functional currency. All references to US$ are to United States dollars.

3. Changes in Accounting Policies and Estimates

(a) Change in accounting estimate

Up to September 30, 2013, Harvest calculated depletion expense using a unit-of-production method where all unamortized PP&E costs were depleted based on proved developed oil and gas reserves.

As at October 1, 2013, a change in estimate was prospectively applied to the depletion calculation whereby costs related to developed oil and gas properties continue to be depleted based on proved developed reserves. Depletion of costs related to undeveloped oil and gas properties will start once such properties are developed. The costs relating to undeveloped oil and gas assets are transferred to the depletable pool as the underlying reserves are developed through drilling activities. The method of depleting oil and gas assets using the unit-of- production method over proved developed reserves remains unchanged.

Harvest's reserves profile has been trending towards a greater weighting of undeveloped reserves as a proportion of total reserves which triggered management to review the historical capital expenditures, reserves profile, and expected production profile of the Company. This change in estimate was made after the review and management concluded that the new estimation method would provide better matching of PP&E costs against the economic benefits from the periodic consumption of developed and undeveloped oil and gas assets of the Company.

If the new estimation method had been applied for the full year 2013, then the annual depreciation and depletion expense would be $83.4 million lower than if the previous estimation method remained applicable for the full year. Harvest expects a similar magnitude of decrease to the depletion and depreciation expense for 2014. Harvest could not determine the effect of the change in estimate for future periods beyond 2014 as the information will not be meaningful since reserves estimates, production profile and capital expenditures for future periods are subject to high level of uncertainty.

(b) Changes in accounting policies

Effective January 1, 2013, Harvest has adopted the following new IFRS standards and amendments:

- IAS 19, "Employee Benefits", changes the recognition and measurement of defined benefit pension expense and termination benefits and expands disclosure requirements for all employee benefit plans. The amendments to the standard include the requirement to recognize changes in the defined benefit obligation and in the fair value of the plan assets as they occur, thus eliminating the corridor approach that was previously permitted under the standard. All actuarial gains and losses must be recognized immediately through other comprehensive income ("OCI") and the net pension liability or asset must be recognized at the full amount of the plan deficit or surplus. An additional change to the standard is the elimination of the concept of expected return on plan assets that was previously recognized in net earnings and the introduction of the concept of net interest cost. The net interest cost is required to be recognized in net earnings and is calculated by applying the discount rate at the beginning of the reporting period to the net defined benefit liability or asset. As well under IAS 19R unvested past service costs are now recognized in profit or loss at the earlier of when the amendment occurs or when the related restructuring or termination costs are recognized. Other amendments include new disclosures, such as quantitative sensitivity disclosures.

  The transition to IAS 19R impacted Harvest's retained earnings and accumulated other comprehensive loss as a result of the recognition of the net interest cost in profit or loss and the elimination of expected return on plan assets. The impacts as at December 31, 2012, January 1, 2012 and January 1, 2011, were an increase in the cumulative prior periods' pre-tax pension expense of $2.7 million, $1.6 million, and $0.7 million, respectively ($2.2 million, $1.3 million and $0.6 million after-tax, respectively) and a corresponding decrease in actuarial gains and losses recognized in accumulated other comprehensive loss.

  For the year ended December 31, 2012, operating expense increased by $1.1 million (2011 – increased by $0.9 million), as a result of increased pension expense and net actuarial losses on defined benefit plans recognized in other comprehensive loss decreased by $1.1 million pre-tax or $0.9 million after-tax (2011 – decreased by $0.9 million pre-tax or $0.7 million after-tax).

  Harvest has also reviewed the classification of its accrual for the long term incentive program and reclassified the portion that will not be paid within the next 12 months to the line item "long-term liability" on the balance sheet. The balance of $3.0 million as at December 31, 2012 and $1.9 million as at January 1, 2012 were reclassified to long-term liabilities.

  The rest of the amendments within IAS 19R did not have any financial impact to Harvest.

- IFRS 10, "Consolidated Financial Statements", replaces the consolidation requirements in SIC-12, "Consolidation – Special Purpose Entities" and a portion of IAS 27. IFRS 10 changes the definition of control under IFRS. The retrospective application of this standard does not have any impact on Harvest's financial statements.

- IFRS 11, "Joint Arrangements", focuses on the rights and obligations of the joint arrangement, rather than its legal form and requires joint arrangements to be classified either as joint operations or joint ventures. The retrospective application of this standard does not have any impact on Harvest's financial statements as substantially all assets are held in joint operations.

- IFRS 12, "Disclosure of Interest in Other Entities", is a comprehensive standard on disclosure requirements for all forms of interests in other entities, including joint arrangements, associates, structure entities and other off balance sheet interests. The retrospective application of this standard does not have any impact on Harvest's financial statements other than additional annual disclosures.

- IFRS 13, "Fair Value Measurement", provides a single source of guidance for fair value measurement and enhances disclosure requirements for information regarding fair value measurements. The adoption of this standard does not have any impact on Harvest's financial statements, other than increasing the level of disclosures provided in note 16, Financial Instruments.

- The amendments to IFRS 7 "Financial Instruments: Disclosures" enhanced the disclosure requirements related to offsetting of financial assets and financial liabilities. The adoption of these amendments does not have any impact to Harvest's financial statements, other than increasing the level of annual disclosures provided in note 16, Financial Instruments.

- In May 2013, the IASB released an amendment to IAS 36, "Impairment of Assets". This amendment requires an entity to disclose the recoverable amount of a cash generating unit for which the entity has recognized or reversed an impairment loss during the reporting period. If the recoverable amount was determined using fair value less costs of disposal, detailed disclosure of how it has been measured will be required. The amendment requires retrospective application and is effective for annual periods beginning on or after January 1, 2014. As allowed by the standard, Harvest early adopted the amendment in the current period. Refer to note 9, Property, Plant and Equipment for the amended disclosure.

(c) Accounting pronouncements

- On June 27, 2013, the IASB issued amendments to IAS 39 "Financial Instruments: Recognition and Measurement" regarding hedge accounting and novation of derivatives. The amendment provides a relief from discontinuing hedge accounting when novation of a hedging instrument to a central counterparty meets specified criteria. The amendments are effective for annual periods beginning on or after January 1, 2014. Harvest does not expect material impact to its consolidated financial statements from this amendment.

- IFRS 9 "Financial Instruments" is a three-phase project intended to replace IAS 39 "Financial Instruments: Recognition and Measurement". In November 2009, the IASB issued the first phase of IFRS 9, which addresses classification and measurement of financial assets. In October 2010, IFRS 9 was updated to include guidance on financial liabilities and derecognition of financial instruments. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

  In November 2013, IFRS 9 was amended to include guidance on hedge accounting and allow entities to early adopt the requirement to recognize changes in fair value attributable to changes in an entity's own credit risk, from financial liabilities designated under the fair value option, in OCI. In addition, the previous mandatory effective date of January 1, 2015 was removed but the standard is still available for early adoption. As the standard is still under development by the IASB, the full impact of this standard on Harvest's consolidated financial statements will not be known until the project is complete. Harvest will continue to monitor the changes to this standard as they arise and will assess the impact accordingly.

- In December 2011, the IASB issued amendments to IAS 32 "Financial Instruments: Presentation" to clarify the requirements for offsetting of financial assets and financial liabilities. The amendments to IAS 32 clarify that the right to offset must be available on the current date and cannot be contingent on a future event. The amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, requiring retrospective application. Harvest does not expect material impact to its consolidated financial statements from this amendment.

4. Significant Accounting Policies

(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. Subsidiaries are fully consolidated from the date of acquisition, being the date on which Harvest obtains control, and continue to be consolidated until the date that such control ceases. Control is achieved when Harvest is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, Harvest controls its subsidiaries as the Company has all of the following via its 100% ownership:

- Power over the investee (i.e., existing rights that give it the current ability to direct the relevant activities of the investee)
- Exposure, or rights, to variable returns from its involvement with the investee
- The ability to use its power over the investee to affect its returns

The financial statements of the subsidiaries are prepared for the same reporting period as Harvest, using consistent accounting policies. The consolidated financial statements of the Company include the following subsidiaries:

Subsidiary	Principal activities	Country of incorporation	% Equity interest
Harvest Breeze Trust No. 1	Oil exploration and production	Canada	100
Harvest Breeze Trust No. 2	Oil exploration and production	Canada	100
Breeze Resources Partnership	Oil exploration and production	Canada	100
Hay River Partnership	Oil exploration and production	Canada	100
North Atlantic Refining Limited	Petroleum refining and marketing	Canada	100

(b) Interests in Joint Arrangements

Harvest conducts substantially all of its Upstream petroleum and natural gas production activities through joint operations. Joint operation is a type of joint arrangement over which two or more parties have joint control and rights to the assets and obligations for the liabilities, relating to the arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities (being those that significantly affect the returns of the arrangement) require unanimous consent of the parties sharing control. Harvest does not have any joint arrangements that are material to the Company, or that are structured using separate vehicles. In relation to its interests in joint operations, Harvest recognizes in the consolidated financial statements its share of assets, liabilities, revenues and expenses of the arrangements.

(c) Revenue Recognition

Revenues associated with the sale of crude oil, 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. Revenues for retail services are recorded when the services are provided. Revenues are measured at the fair value of the consideration received or receivable.

(d) Inventories

Inventories are carried at the lower of cost or net realizable value. The costs of petroleum product inventory are determined using the weighted average cost method in Downstream and the first in, first out method in Upstream. Inventory costs include all cost of production such as the cost of purchased crude oil and other feedstocks, other related operating costs and purchased products for resale. The valuation of inventory is reviewed at the end of each month. When the circumstances that previously caused inventories to be written down below cost no longer exist or when there is clear evidence of an increase in net realizable value because of changed economic circumstances, the amount of the write-down is reversed. The reversal is limited to the amount of the original write-down. The costs of parts and supplies inventories are determined under the average cost method.

(e) Property, Plant, and Equipment ("PP&E") and Exploration and Evaluation ("E&E") Assets

(i) Upstream and BlackGold

Exploration and evaluation expenditures

Prior to acquiring the legal rights to explore an area, all costs are charged directly to the statement of comprehensive loss as E&E expense.

Once the legal rights to explore are acquired, all costs directly associated with the E&E are capitalized. E&E costs are those expenditures incurred for identifying, exploring and evaluating new pools including acquisition of land and mineral leases, geological and geophysical costs, decommissioning costs, E&E drilling, sampling, appraisals and directly attributable general and administrative costs. All such costs are subject to technical, commercial and management review to confirm the continued intent to develop. When this is no longer the case, the costs are charged to net income as E&E expense. When technical feasibility and commercial viability are established, the relevant expenditure is transferred to PP&E after impairment is assessed and any resulting impairment loss is recognized. If no potentially commercial petroleum is discovered from exploration drilling, the relating E&E assets are written off through the statement of comprehensive loss.

E&E assets are not amortized but are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, E&E assets are allocated to cash generating units ("CGUs"). The impairment of E&E assets, and any eventual reversal thereof, is recognized as E&E expense in the statement of comprehensive loss.

Development costs

The Upstream and BlackGold PP&E generally represent costs incurred in acquiring and developing proved and/or probable reserves, and bringing in or enhancing production from such reserves. Development costs include the initial purchase price and directly attributable costs relating to land and mineral leases, geological and seismic studies, property acquisitions, development drilling, construction of gathering systems and infrastructure facilities, decommissioning costs, transfers from E&E assets, and for qualifying assets, borrowing costs. These costs are accumulated on a field or an area basis (major components).

Major capital maintenance projects such as well work-overs, major overhauls and turnarounds are capitalized but general maintenance and repair costs are charged against income. Where a major part of an asset is replaced, it is capitalized within PP&E and the carrying amount of the replaced component is derecognized immediately. The capitalized major capital maintenance projects and replacement parts are amortized as separate components if their useful lives are different from the associated assets. The costs of the day-to-day servicing of PP&E are recognized in net income as incurred.

PP&E are stated at historical cost, less accumulated depreciation, depletion, amortization and impairment losses.

For exchanges that involve only unproven properties, the exchange is accounted for at cost. Exchanges of development and production assets are measured at fair value unless the exchange transaction lacks commercial substance or if neither the fair value of the assets given up nor the assets received can be reliably estimated. Any gains or losses on de-recognition of the asset given up is included in net income.

Depletion, Depreciation and Amortization

Costs incurred related to developed oil and gas properties are depleted using the unit-of-production basis over the proved developed reserves. Cost related to undeveloped oil and gas properties are not immediately included in the depletable pool of developed assets but are transferred to the depletable pool as the reserves are developed through drilling activities.

Certain major components within PP&E such as capitalized maintenance and replacement parts are amortized on a straight-line basis over their respective useful lives, which in general is around four years. Costs of major development projects under construction are excluded from the costs subject to depletion until they are available for use.

Corporate and administrative assets are depreciated on a straight-line basis over the individual assets' useful lives.

Harvest reviews its PP&E's residual values, useful lives and methods of depreciation at each reporting period and adjusted prospectively, if appropriate.

(ii) *Downstream*

PP&E related to the refining assets are recorded at cost. General maintenance and repair costs are expensed as incurred. Major replacements and capital maintenance projects such as turnaround costs are capitalized. Improvements that increase or prolong the service life or capacity of an asset are capitalized.

Depreciation

When significant parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components). Depreciation of recorded cost less the residual value is provided on a straight- line basis over the estimated useful life of the major components as set out below.

Asset	Period
Refining and production plant:	
Processing equipment	5 – 35 years
Structures	15 – 20 years
Catalysts and turnarounds	2 – 8 years
Tugs	25 years
Buildings	10 – 20 years
Vehicles	2 – 7 years
Office and computer equipment	3 – 5 years

(iii) Disposal of assets

An item of PP&E and any significant part initially recognized is derecognized upon disposal or abandonment. Gains and losses on disposal are determined by comparing the proceeds from disposal with the carrying amount of the item of PP&E and are recognized in the period of disposal.

(iv) Impairment of Property, Plant and Equipment and Exploration and Evaluation Assets

Harvest assesses, at each reporting date, whether there is an indication that an asset may be impaired. If any indication exists, Harvest estimates the asset's recoverable amount. An asset's recoverable amount is the higher of an asset's fair value less costs to sell ("FVLCS") and its value-in-use ("VIU"). The recoverable amount is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets. In such case, an impairment test is performed at the CGUs level. A CGU is a group of assets that Harvest aggregates based on their ability to generate largely independent cash flows.

Where the carrying amount of an asset or CGU exceeds its recoverable amount, the asset is considered impaired and is written down to its recoverable amount. To determine VIU, the Company estimates the present value of the future net cash flows expected to derive from the continued use of the asset or CGU without consideration for potential enhancement or improvement of the underlying asset's performance. Discount rates that reflect the market assessments of the time value of money and the risks specific to the asset or CGU are used. In determining FVLCS, discounted cash flows and recent market transactions are taken into account, if available. These calculations are corroborated by valuation multiples or other available fair value indicators.

For assets excluding goodwill, an assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the previously recognized impairment loss is reversed. The reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount, nor exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior periods. Such reversal is recognized in net income.

(f) Capitalized Interest

Interest on major development projects is capitalized until the project is complete using the weighted-average interest rate on Harvest's general borrowings. In situations where Harvest borrows funds specifically to acquire a qualifying asset or project, interests on these funds are also capitalized. Capitalized interest is limited to the actual interest incurred.

(g) Assets Held for Sale

Non-current assets are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition.

The assets or disposal groups classified as held for sale are measured at the lower of the carrying amount and FVLCS, with impairments recognized in the consolidated statement of comprehensive loss. Non-current assets held for sale are presented in current assets and liabilities within the consolidated statement of financial positions. Assets held for sale are not depreciated, depleted or amortized.

(h) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method. The cost of an acquisition including any contingent consideration is measured as the aggregate of the consideration transferred at acquisition date fair value. The acquired identifiable net assets are measured at their fair value at the date of acquisition. Any excess of the consideration transferred over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the consideration transferred below the fair value of the net assets acquired is recorded as a gain in net income. Associated transaction costs are expensed when incurred. Any contingent consideration to be transferred to the vendor is recognized at fair value at the acquisition date. Contingent consideration classified as a financial asset or liability is measured at fair value, with changes in fair value recorded in net income.

Those petroleum reserves and resources that are able to be reliably valued are recognized in the assessment of fair values on acquisition. The fair value of oil and natural gas interests is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on reserve estimates. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to groups of CGUs that are expected to benefit from the combination. Goodwill is carried at cost less impairment and is not amortized.

Goodwill is assessed for impairment annually at year-end or more frequently if events occur that could result in impairment. The recoverable amount is determined by calculating the recoverable amount of the group of CGUs that goodwill has been allocated to. The excess of the carrying value of goodwill over the recoverable amount is then recognized as impairment and charged to net income in the period in which it occurs. An impairment loss in respect of goodwill is not reversed.

Where goodwill forms part of a CGU and part of the operation in that unit is disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal. Goodwill disposed of in these circumstances is measured based on the relative values of the disposed operation and the portion of the CGU retained.

(i) Provisions

(i) General

Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the Company expects some or all of a provision to be reimbursed, for example, under an insurance contract, the reimbursement is recognized as a separate asset but only when the reimbursement is virtually certain. The expenses relating to provisions are generally presented in the income statement net of any reimbursement except for decommissioning liabilities. If the effect of the time value of money is material, provisions are discounted using a current discount rate that reflects, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognized as a finance cost.

(ii) Decommissioning Liabilities

Harvest recognizes the present value of any decommissioning liabilities 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 risk-free rate to estimate the present value of the expenditure required to settle the present obligation at the reporting date. The associated decommissioning costs are capitalized as part of the carrying amount of the related asset and the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligation are charged against the decommissioning liabilities.

(iii) Environmental Remediation Liabilities

Environmental expenditures related to an existing condition caused by past operations are expensed. Environmental liabilities are recognized when a clean-up is probable and the associated costs can be reliably estimated. The amount recognized is the best estimate of the expenditure required. When the liability will not be settled for a number of years, the amount recognized is the present value of the estimated future expenditure.

(iv) Contingencies

A contingency is disclosed where the existence of an obligation will only be confirmed by future events, or where the amount of a present obligation cannot be measured reliably or will likely not result in an economic outflow. Contingent assets are only disclosed when the inflow of economic benefits is probable.

(j) Income Taxes

Income tax expense comprises current and deferred tax. Income tax expense is recognized in net income except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income tax liabilities and assets are generally not recognized for temporary differences arising on:

- investments in subsidiaries and associates and interests in joint ventures;
- the initial recognition of goodwill; or
- the initial recognition of an asset or liability in a transaction which is not a business combination.

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, and Harvest intends to settle current tax liabilities and assets on a net basis.

Deferred tax assets are recognized for all deductible temporary difference the carry-forward of unused tax credits and any unused tax losses, to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets, both recognized and unrecognized are reviewed at each reporting date and are adjusted to the extent that it is probable that the related tax benefit will be realized.

Harvest is entitled to certain investment tax credits on qualifying manufacturing capital expenditures relating to its Downstream operations. At each period end, Harvest reviews and if appropriate reduces the balance to the extent that it is no longer probable that the investment tax credit will be realized. Any reduction is recorded under “income tax expense (recovery)” in the statement of comprehensive loss.

(k) Post-Employment Benefits

Harvest’s Downstream operations maintains a defined benefit pension plan and a defined benefit health care plan, which cover the majority of its employees and their surviving spouses.

The cost of providing the defined pension benefits and other post–retirement benefits is actuarially determined by an independent financial security firm using the projected unit credit method reflecting management’s best estimates of discount rates, rate of compensation increase, retirement ages of employees, and expected health care costs. The benefit plan expenses include the current service costs and the net interest expense on the net obligation. Net interest expense is calculated by applying the discount rate to the net defined benefit asset or liability. Harvest recognizes its benefit plan expenses under operating expenses in the statement of comprehensive loss. Harvest does not have any past service costs arising from plan amendments, curtailment or restructuring.

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 statement of financial position. Actuarial gains or losses are recognized in other comprehensive income immediately, which are not reclassified to net income in subsequent periods.

(l) Currency Translation

Foreign currency-denominated transactions are translated to the respective functional currencies of Harvest’s entities at exchange rates at the date of the transactions. Non-monetary items measured at historical cost are not subsequently re-translated. Monetary assets and liabilities denominated in foreign currencies are converted into Harvest’s functional currencies at the exchange rate at the reporting date. Conversion gains and losses on monetary items are included in net income in the period in which they arise.

Harvest’s Downstream operations’ functional currency is the U.S. dollar, while Harvest’s presentation currency is the Canadian dollar. Therefore, the Downstream operations’ assets and liabilities are translated at the period-end exchange rates, while revenues and expenses are translated using monthly average rates. Translation gains and losses relating to the foreign operations are included in accumulated other comprehensive income as a separate component of shareholder’s equity.

(m) Financial Instruments

Harvest recognizes financial assets and financial liabilities, including derivatives, on the consolidated statements of financial position when the Company becomes a party to the contract. Financial liabilities are removed from the consolidated financial statements when the liability is extinguished either through settlement of or release from the obligation of the underlying liability. Financial assets are derecognized when (1) the rights to receive cash flows from the assets have expired or (2) the Company has transferred its rights to receive cash flows from the assets or has assumed an obligation to pay the received cash flows in full without material delay to a third party under a ‘pass-through’ arrangement; and either (a) the Company has transferred substantially all the risks and rewards of the assets, or (b) the Company has neither transferred nor retained substantially all the risks and rewards of the assets, but has transferred control of the asset.

Harvest initially measures all financial instruments at fair value. Subsequent measurement of the financial instruments is based on their classification. Financial assets are classified into the following categories: held for trading, available for sale, held-to-maturity investments and loans and receivables. Financial liabilities are classified as held for trading or other financial liabilities. Harvest has not designated any financial asset or liability at fair value through profit or loss.

Commodity contracts that are entered into and continue to be held for the purpose of the receipt or delivery of commodity in accordance with the Company's expected purchase, sale or usage fall within the normal purchase or sale exemption and are accounted for as executor contracts.

Financial assets and financial liabilities classified as held for trading are measured at fair value with changes in those fair values recognized in net income. Financial assets classified as either held-to-maturity or loans and receivables, and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Financial assets classified as available-for-sale are measured at fair values with changes in those fair values recognized in other comprehensive income.

Financial assets and liabilities are offset and the net amount reported in the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis or realize the asset and settle the liability simultaneously.

Transaction costs relating to financial instruments classified as held for trading are expensed in net income in the period that they are incurred. For transaction costs that are directly attributable to the acquisition or issuance of financial instruments not classified as held for trading, they are included in the costs of the financial instruments upon initial recognition.

Harvest assesses at each reporting date whether there is any objective evidence that a financial asset or a group of financial assets is impaired, as a result of one or more events that has occurred after the initial recognition of the asset (an incurred 'loss event') and that loss event has an impact on the estimated future cash flows of the financial asset or the group of financial assets that can be reliably estimated. For loans and receivables, the carrying amount of the asset is reduced through the use of an allowance account and the loss is recognized in the statement of comprehensive loss.

(n) Hedges

Harvest uses derivative financial instruments such as foreign currency contracts and financial commodity contracts to hedge its foreign currency risks and commodity price risks. Such derivative financial instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Derivatives are carried as financial assets when the fair value is positive and as financial liabilities when the fair value is negative. Any gains or losses arising from changes in the fair value of derivatives are recorded in net income, except for the effective portion of cash flow hedges, which is recognized in other comprehensive income.

At the inception of a hedge relationship, Harvest formally designates and documents the hedge relationship to which the Company intends to apply hedge accounting. The designation document includes the risk management objective and strategy for undertaking the hedge, the identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged and how the Company will assess the hedge effectiveness. Upon designation and at each reporting date, Harvest assesses hedge effectiveness by performing regression analysis to assess the relationship between the hedged item and hedging instrument. Only if such hedges are highly effective in achieving offsetting changes in fair value or cash flows will Harvest continue to apply hedge accounting.

The effective portion of the gain or loss on the hedging instrument is recognized directly in other comprehensive income, while any ineffective portion is recognized immediately in net income. Amounts recognized in other comprehensive income are transferred to the statement of comprehensive loss when the hedged transaction affects net income, such as when the hedged forecasted transaction occurs. Where the hedged item is the cost of a non-financial asset or non-financial liability, the amounts recognized in other comprehensive income are transferred to the initial carrying amount of the non-financial asset or liability.

If the forecast transaction is no longer expected to occur, the cumulative gain or loss previously recognized in other comprehensive income is transferred to net income. If the hedging instrument expires or is sold, terminated or exercised without replacement or rollover, or if its designation as a hedge is revoked, any cumulative gains or losses previously recognized in other comprehensive income remain in other comprehensive income until the forecast transaction affects net income.

(o) Leases

Leases or other arrangements that convey a right to use a specific asset are classified as either finance or operating leases. Finance leases transfer to the Company substantially all of the risks and benefits incidental to ownership of the leased item. Finance leases are capitalized at the commencement of the lease term at the lower of the fair value of the leased asset or the present value of the minimum lease payments. Capitalized leased assets are amortized over the shorter of the estimated useful life of the assets and the lease term. Operating lease payments are recognized as an expense in the income statement on a straight line basis over the lease term.

(p) Fair Value Measurement

Harvest measures derivatives at fair value at each balance sheet date and, for the purposes of impairment testing, uses FVLCS to determine the recoverable amount of some of its non-financial assets. Also, fair values of financial instruments measured at amortized cost are disclosed in note 16.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either in the following markets that are accessible by the Company:

- the principal market for the asset or liability, or
- in the absence of a principal market, the most advantageous market for the asset or liability

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.

Harvest uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy; described as follows, based on the lowest-level input that is significant to the fair value measurement as a whole:

- Level 1 — Quoted (unadjusted) market prices in active markets for identical assets or liabilities
- Level 2 — Valuation techniques for which the lowest-level input that is significant to the fair value measurement is directly or indirectly observable
- Level 3 — Valuation techniques for which the lowest-level input that is significant to the fair value measurement is unobservable

For assets and liabilities that are recognized in the financial statements on a recurring basis, Harvest determines whether transfers have occurred between levels in the hierarchy by reassessing categorization (based on the lowest-level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

5. Use of Estimates and Judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below:

(a) ***Joint arrangements***

Judgment is required to determine when Harvest has joint control over an arrangement, which requires an assessment of the relevant activities and when the decisions in relation to those activities require unanimous consent. Harvest has determined that the relevant activities for its joint arrangements are those relating to the operating and capital decisions of the arrangement, such as approval of the capital expenditure program. The considerations made in determining joint control are similar to those necessary to determine control over subsidiaries. Refer to note 4 for more details.

(b) ***Reserves***

The provision for depletion and depreciation of Upstream assets is calculated on the unit-of-production method based on proved developed reserves. As well, reserve estimates impact net income through the application of impairment tests. Provision for Upstream and BlackGold's decommissioning liability may change as changes in reserve lives affect the timing of decommissioning activities. The recognition and carrying value of deferred income tax assets relating to Upstream and BlackGold may change as reserve estimates impact Harvest's estimates of the likely recoverability of such assets. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income and PP&E.

The process of estimating reserves is complex and requires significant judgments based on available geological, geophysical, engineering and economic data. In the process of estimating the recoverable oil and natural gas reserves and related future net cash flows, Harvest incorporates 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 commodity prices and quality differentials;
- discount rates; and
- future development costs.

On an annual basis, the Company engages qualified, Independent Reserves Evaluator to evaluate Harvest's reserves data.

Significant judgment is required to determine the future economic benefits of the oil and gas assets and in turn, to derive the proper DD&A estimate. This includes the interpretation and application of reserves estimates, the selection of the reserves base for the unit of production calculation and the matching of capitalized costs with the benefit of production.

(c) ***Impairment of long-lived assets***

Long-lived assets (goodwill, PP&E and E&E assets) are aggregated into CGUs based on their ability to generate largely independent cash inflows and are used for impairment testing. The determination of the Company's CGUs is subject to significant judgment; product type, internal operational teams, geology and geography were key factors considered when grouping Harvest's oil and gas assets into the CGUs.

PP&E is tested for impairment when indications of impairment exist. PP&E impairment indicators include declines in commodity prices, production, reserves and operating results, cost overruns and construction delays. E&E impairment indicators include expiration of the right to explore and cessation of exploration in specific areas, lack of potential for commercial viability and technical feasibility and when E&E costs are not expected to be recovered from successful development of an area. The determination of whether such indicators exist requires significant judgment.

The recoverable amounts of CGUs and individual assets are determined based on the higher of VIU calculations and estimated FVLCS. To determine the recoverable amounts, Harvest uses reserve estimates for both the Upstream and BlackGold operating segments and expected future cash flows for the Downstream operations. The estimates of reserves, future commodity prices, refining margins, forecast refinery utilization and yields, discount rates, operating expenses and sustaining capital expenditures require significant judgments. FVLCS is determined using significant judgments, see note 5(i) below for further discussion.

(d) ***Provisions***

In the determination of provisions, management is required to make a significant number of estimates and assumptions with respect to activities that will occur in the future including the ultimate amounts and timing of settlements, inflation factors, risk-free discount rates, emergence of new restoration techniques and expected changes in legal, regulatory, environmental and political environments. A change in any one of the assumptions could impact the estimated future obligation and in return, net income and in the case of decommissioning liabilities, PP&E.

(e) ***Employee benefits***

Harvest's Downstream operations maintains a defined benefit pension plan and provides certain post-retirement health care benefits, which cover the majority of its Downstream employees and their surviving spouses. An independent actuary determines the costs of the Company's employee future benefit programs using certain management assumptions and estimates such as, the expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, employee turnover and discount rates. The obligation and expense recorded related to Harvest's employee future benefit plans could increase or decrease if there were to be a change in these estimates.

The Company also maintains a long-term incentive plan which is a performance-based program. As a result, the compensation costs accrued for the plan are subject to the estimation of what the ultimate payout will be and are subject to management's judgment as to whether or not the performance criteria will be met.

(f) ***Fair value of acquired assets and liabilities***

Business acquisitions are accounted for using the acquisition method. Under this method, the consideration transferred is allocated to the assets acquired and the liabilities assumed based on the fair values at the time of the acquisition. In determining the fair value of the assets and liabilities, Harvest is often required to make assumptions and estimates, such as reserves, future commodity prices, fair value of undeveloped land, discount rates, decommissioning liabilities and possible outcome of any assumed contingencies. Changes in any of these assumptions would impact amounts assigned to assets and liabilities and goodwill in the consideration transferred allocation and as a result, future net income.

(g) ***Risk management contracts***

Derivative risk management contracts are valued using valuation techniques with market observable inputs. The most frequently applied valuation techniques include forward pricing and swap models, using present value calculations. The models incorporate various inputs including the credit quality of counterparties, foreign exchange spot and forward rates, interest rate curves and forward rate curves of the underlying commodity. Changes in any of these assumptions would impact fair value of the risk management contracts and as a result, future net income and other comprehensive income. For risk management contracts designated as hedges, changes in the above mentioned assumptions may impact hedge effectiveness assessment and Harvest's ability to continue applying hedge accounting.

(h) ***Income taxes***

Tax interpretations, regulations and legislation in the various jurisdictions in which Harvest and its subsidiaries operate are subject to change. The Company is also subject to income tax audits and reassessments which may change its provision for income taxes. Therefore, the determination of income taxes is by nature complex, and requires making certain estimates and assumptions.

Harvest recognizes the net deferred tax benefit related to deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the net deferred tax assets recorded at the reporting date could be impacted.

(i) ***Fair value measurements***

Significant judgment is required to determine what assumptions market participants would use to price an asset or a liability, such as forward prices, foreign exchange rates and discount rates. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use. To determine "highest and best use" requires further judgment. Changes in estimates and assumptions about these inputs could affect the reported fair value.

(j) ***Contingencies***

Contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

6. Segment Information

Harvest's operating segments are determined based on the nature of the products and services. The following summary describes the operations in each of the segments:

- Upstream operations consist of exploration, development, production and subsequent sale of petroleum, natural gas and natural gas liquids in western Canada.
- The BlackGold Oil sands project is located near Conklin, Alberta. Phase 1 of the project that is designed to produce 10,000 barrels of bitumen per day is currently under construction and development. BlackGold will use steam assisted gravity drainage technology to recover bitumen.
- Downstream operations include the purchase and refining of crude oil at a medium gravity sour crude oil hydrocracking refinery, and the sale of the refined products to commercial, wholesale and retail customers. Downstream is located in the Province of Newfoundland and Labrador.

	Year Ended December 31[3]								
	Upstream[2]			Downstream[2]			Total		
	2013	2012	2011	**2013**	2012 *(Restated)**	2011 *(Restated)**	**2013**	2012 *(Restated)**	2011 *(Restated)**
Petroleum, natural gas and refined products sales[1]	**$ 1,101.7**	$ 1,193.5	$ 1,286.9	**$ 4,416.9**	$ 4,752.1	$ 3,302.3	**$ 5,518.6**	$ 5,945.6	$ 4,589.2
Royalties	**(153.9)**	(164.6)	(195.5)	**–**	–	–	**(153.9)**	(164.6)	(195.5)
Revenues	**$ 947.8**	$ 1,028.9	$ 1,091.4	**$ 4,416.9**	$ 4,752.1	$ 3,302.3	**$ 5,364.7**	$ 5,781.0	$ 4,393.7
Expenses									
Purchased products for resale and processing	**–**	–	–	**4,327.4**	4,520.3	3,118.1	**4,327.4**	4,520.3	3,118.1
Operating	**345.6**	359.0	350.4	**233.1**	262.6	226.6	**578.7**	621.6	577.0
Transportation and marketing	**22.6**	22.2	29.6	**5.4**	4.4	6.3	**28.0**	26.6	35.9
General and administrative	**68.1**	65.0	60.8	**0.6**	0.6	1.8	**68.7**	65.6	62.6
Depletion, depreciation and amortization	**530.0**	579.5	535.7	**82.8**	108.9	91.0	**612.8**	688.4	626.7
Exploration and evaluation	**12.3**	24.9	18.3	**–**	–	–	**12.3**	24.9	18.3
Gains on disposition of PP&E	**(33.9)**	(30.3)	(7.9)	**(0.2)**	–	–	**(34.1)**	(30.3)	(7.9)
Risk management contracts gains	**(4.4)**	(0.5)	(6.7)	**–**	–	–	**(4.4)**	(0.5)	(6.7)
Impairment on PP&E	**24.1**	21.8	–	**458.9**	535.5	–	**483.0**	557.3	–
Operating income (loss)	**$ (16.6)**	$ (12.7)	$ 111.2	**$ (691.1)**	$ (680.2)	$ (141.5)	**$ (707.7)**	$ (692.9)	$ (30.3)
Finance costs							**94.2**	111.0	109.1
Foreign exchange gains (losses)							**44.2**	(1.3)	(4.0)
Loss before income tax							**$ (846.1)**	$ (802.6)	$ (135.4)
Income tax recovery							**(64.2)**	(81.6)	(30.0)
Net loss							**$ (781.9)**	$ (721.0)	$ (105.4)

*See Note 3.

(1) Of the total Downstream revenue, one customer represents sales of $3.7 billion for the year ended December 31, 2013 (2012- one customer with sales of $4.0 billion; 2011 – two customers with sales of $1.6 billion and $586 million). No other single customer within either segment represents greater than 10% of Harvest's total revenue.

(2) There is no intersegment activity.

(3) The BlackGold segment is under development, as such, there are no operating activities to report.

	Year Ended December 31, 2013			
Capital Additions	Upstream	BlackGold	Downstream	Total
Additions to PP&E	**$ 305.6**	**$ 444.5**	**$ 53.2**	**$ 803.3**
Additions to E&E	**16.7**	**–**	**–**	**16.7**
Property acquisitions (dispositions), net	**(155.6)**	**0.7**	**(0.2)**	**(155.1)**
Total expenditures	**$ 166.7**	**$ 445.2**	**$ 53.0**	**$ 664.9**

Capital Additions	Year Ended December 31, 2012 Upstream	BlackGold	Downstream	Total
Additions to PP&E	$ 406.4	$ 164.1	$ 54.2	$ 624.7
Additions to E&E	41.1	–	–	41.1
Property acquisitions (dispositions), net	(84.3)	–	–	(84.3)
Total expenditures	$ 363.2	$ 164.1	$ 54.2	$ 581.5

Capital Additions	Year Ended December 31, 2011 Upstream	BlackGold	Downstream	Total
Business acquisition	$ 548.3	$ –	$ –	$ 548.3
Additions to PP&E	588.7	101.2	284.2	974.1
Additions to E&E	50.9	–	–	50.9
Property acquisitions (dispositions), net	2.6	–	–	2.6
Total expenditures	$ 1,190.5	$ 101.2	$ 284.2	$ 1,575.9

	Total Assets	**PP&E**	**E&E**	**Goodwill**
December 31, 2013				
Upstream	**$ 3,794.0**	**$ 3,166.2**	**$ 59.4**	**$ 379.8**
BlackGold	**1,144.0**	**1,138.8**	–	–
Downstream	**351.9**	**156.4**	–	–
Total	**$ 5,289.9**	**$ 4,461.4**	**$ 59.4**	**$ 379.8**
December 31, 2012				
Upstream	$ 4,146.6	$ 3,507.6	$ 73.4	$ 391.8
BlackGold	684.9	679.8	–	–
Downstream	823.1	604.5	–	–
Total	$ 5,654.6	$ 4,791.9	$ 73.4	$ 391.8
January 1, 2012				
Upstream	$ 4,292.9	$ 3,687.7	$ 74.5	$ 404.9
BlackGold	583.4	497.3	–	–
Downstream	1,408.1	1,222.5	–	–
Total	$ 6,284.4	$ 5,407.5	$ 74.5	$ 404.9

7. Business Combination

On February 28, 2011, Harvest acquired certain petroleum and natural gas assets of Hunt Oil Company of Canada, Inc. and Hunt Oil Alberta, Inc. (collectively “Hunt”) for total cash consideration of $511.0 million. KNOC provided $505.4 million of equity to fund the acquisition and acquisition costs were $1.3 million for the year ended December 31, 2011.

The acquisition was accounted for as a business combination. The fair values of identifiable assets and liabilities, including interim adjustments as at the date of acquisition were:

Property, plant and equipment	$ 530.9
Evaluation and exploration assets	18.6
Decommissioning and environmental remediation liabilities	(38.0)
Other liabilities	(0.5)
Cash consideration	$ 511.0

The final review of the fair value of the purchase price allocation was completed at December 31, 2011. These consolidated financial statements incorporate the results of operations of Hunt from February 28, 2011. For the year ended December 31, 2011, the Hunt assets contributed $133.0 million of revenue and $96.6 million to Harvest’s earnings before depletion and income tax. If the acquisition had been completed on the first day of 2011, Harvest’s revenues for the year ended December 31, 2011 would have been $14.6 million higher and the earnings before depletion and income tax would have been $7.4 million higher.

8. Assets Held For Sale

In February 2013, Harvest completed the sale of selected non-core oil and gas properties in Alberta and British Columbia that had been recorded in assets held for sale for proceeds of approximately $9.0 million. The sale of these assets resulted in a gain of $4.3 million in Harvest's Upstream segment, which is included in gains on disposition of property, plant and equipment in the statement of comprehensive loss for the year ended December 31, 2013.

Assets held for sale		
Exploration and evaluation	$	0.4
Property, plant and equipment, net		13.8
Goodwill		2.7
Assets held for sale December 31, 2012	$	16.9
Disposals		(16.9)
Assets held for sale December 31, 2013	**$**	−

Liabilities associated with assets held for sale		
Decommissioning liabilities December 31, 2012	$	11.9
Disposals		(11.9)
Liabilities associated with assets held for sale December 31, 2013	**$**	−

9. Property, Plant and Equipment ("PP&E")

		Upstream		BlackGold		Downstream		Total
Cost:								
As at January 1, 2012	$	4,707.7	$	497.3	$	1,378.6	$	6,583.6
Additions		406.4		164.1		54.2		624.7
Acquisitions		1.3		−		−		1.3
Change in decommissioning liabilities		82.7		18.4		1.2		102.3
Transfers from E&E		19.2		−		−		19.2
Exchange adjustment		−		−		(29.5)		(29.5)
Disposals		(108.8)		−		(11.5)		(120.3)
Investment tax credits		−		−		(2.7)		(2.7)
Transfers to assets held for sale		(23.0)		−		−		(23.0)
As at December 31, 2012	$	5,085.5	$	679.8	$	1,390.3	$	7,155.6
Additions		305.6		444.5		53.2		803.3
Acquisitions		16.3		0.7		−		17.0
Disposals		(177.9)		−		(4.9)		(182.8)
Change in decommissioning liabilities		31.5		13.8		−		45.3
Transfers from E&E		11.3		−		−		11.3
Exchange adjustment		−		−		99.4		99.4
As at December 31, 2013	**$**	**5,272.3**	**$**	**1,138.8**	**$**	**1,538.0**	**$**	**7,949.1**
Accumulated depletion, depreciation, amortization and impairment losses:								
As at January 1, 2012	$	1,020.0	$	−	$	156.1	$	1,176.1
Depreciation, depletion and amortization		579.5		−		108.9		688.4
Disposals		(34.2)		−		(11.5)		(45.7)
Impairment		21.8		−		535.5		557.3
Exchange adjustment		−		−		(3.2)		(3.2)
Transfers to assets held for sale		(9.2)		−		−		(9.2)
As at December 31, 2012	$	1,577.9	$	−	$	785.8	$	2,363.7
Depreciation, depletion and amortization		530.0		−		82.8		612.8
Disposals		(25.9)		−		(4.7)		(30.6)
Impairment		24.1		−		458.9		483.0
Exchange adjustment		−		−		58.8		58.8
As at December 31, 2013	**$**	**2,106.1**	**$**	**−**	**$**	**1,381.6**	**$**	**3,487.7**
Net Book Value:								
As at December 31, 2013	**$**	**3,166.2**	**$**	**1,138.8**	**$**	**156.4**	**$**	**4,461.4**
As at December 31, 2012	$	3,507.6	$	679.8	$	604.5	$	4,791.9
As at January 1, 2012	$	3,687.7	$	497.3	$	1,222.5	$	5,407.5

General and administrative costs directly attributable to PP&E addition activities of $19.6 million have been capitalized during the year ended December 31, 2013 (2012 – $21.6 million; 2011 – $21.4 million). Borrowing costs relating to the development of BlackGold assets have been capitalized within PP&E during the year ended December 31, 2013 in the amount of $19.8 million (2012 – $10.8 million; 2011 – $4.5 million), at a weighted average interest rate of 4.8% (2012 – 5.7%; 2011 – 6.7%) . No borrowing costs were capitalized for year ended December 31, 2013 for the Downstream debottlenecking project as this asset was written down during the fourth quarter of 2012 and no longer qualifies for capitalizing borrowing costs (2012 – $2.7 million at a weighted average interest rate of 5.7%; 2011 – $4.1 million at a weighted average interest rate of 6.7%) . PP&E additions also include non-cash additions relating to the BlackGold deferred payment of $71.5 million (December 31, 2012 – $4.7 million; January 1, 2012 – $nil) (see note 18).

At December 31, 2013, the following costs were excluded from the asset base subject to depreciation, depletion and amortization: BlackGold oil sands assets of $1.1 billion (December 31, 2012 – $679.8 million; January 1, 2012 –$497.3 million), Downstream assets under construction of $37.0 million (December 31, 2012 – $42.4 million; January 1, 2012 – $102.5 million); and Downstream major parts inventory of $8.3 million (December 31, 2012 – $7.4 million; January 1, 2012 – $7.5 million).

Downstream operations have experienced continuing losses due to lower than expected crack spreads and increased regulatory costs. During the second half of 2013, Harvest commenced a process to evaluate various business opportunities pertaining to the Downstream business, including but not limited to introduction of joint venture partners, disposition in whole or in part as well as multiple economic scenarios for future operations. As at December 31, 2013, no decision has been made out of this review, but during the review process, management gathered various external information that triggered an impairment assessment of the refinery. As a result, during the fourth quarter of 2013, Downstream recorded an impairment of $458.9 million (2012 – $535.5 million; 2011 – $nil) on its refinery CGU relating to the PP&E to reflect the excess of the carrying value over the assessed recoverable amount. The recoverable amount was based on the CGU's VIU, estimated using the net present value of future cash flows and using a pre-tax discount rate of 16% (2012 – 16%; 2011 – nil). Cash flows were projected using the estimated life of the facility which is 40 years. The recoverable amount as at December 31, 2013 for the refinery CGU was $132.7 million (2012 – $581.9 million). The VIU model did not include any expected cash flows from capital enhancement projects but does assumes a partial plant outage for major maintenance work every two years commencing in 2014 and a full plant outage every six years commencing 2016. The pre-tax discount rate of 16% incorporated the various risks inherent in the industry and in forecasting uncertainties. The following assumptions where used in the VIU model for determining gross margin per barrel:

Year	Crack spread per bbl throughput ($US/bbl)	Crude feedstock differential ($US/bbl)
2014	6.05	-3.74
2015	9.55	-6.54
2016	8.82	-7.23
2017	9.79	-8.11
2018	9.92	-8.74
Thereafter	+2%/year	+2%/year

An increase of 100 bps in the pre-tax discount rate would result in an additional impairment of $21.2 million, while a 5% decrease in gross margin per barrel would result in an additional impairment of $123.4 million.

During 2013, Harvest recognized an impairment loss of $24.1 million (2012 – $21.8 million; 2011 – $nil) against its Upstream PP&E relating to certain gas properties in the South Alberta gas CGU, which was triggered by reserves write-down as a result of lower forecast development activities, a decline in the long-term gas prices and reduced estimates of recoverable NGLs from the CGU. The recoverable amount was based on the assets' VIU, estimated using the net present value of proved plus probable reserves discounted at a pre-tax rate of 8% (2012 – 10%; 2011 – nil). Please refer to note 10 for the forecast prices used in the VIU model. The recoverable amount as at December 31, 2013 for the South Alberta gas CGU was $77.7 million (2012 – $155.1 million). A 200 bps increase in the discount rate would result in an additional impairment for the South Alberta gas CGU of approximately $4.2 million while a 10% decrease in the forward gas price estimate would result in an additional impairment of approximately $10.5 million.

During 2013, Harvest closed the disposition of certain non-core oil and gas assets in west central Saskatchewan and Alberta for total proceeds of approximately $173.9 million. Harvest recognized $33.9 million of gains on disposition during the year ended December 31, 2013 (2012 – $30.3 million; 2011 – $7.9 million) relating to the de-recognition of PP&E, E&E, goodwill and decommissioning liabilities.

10. Goodwill

As at January 1, 2012	$	404.9
Disposals		(10.4)
Transfers to assets held for sale		(2.7)
As at December 31, 2012	$	391.8
Disposals		(12.0)
As at December 31, 2013	**$**	**379.8**

Goodwill of $379.8 million (December 31, 2012 - $391.8 million; January 1, 2012 - $404.9 million) has been allocated to the Upstream operating segment. In assessing whether goodwill has been impaired, the carrying amount of the Upstream operating segment (including goodwill) is compared with the recoverable amount of the Upstream operating segment. The estimated recoverable amount was based on the Upstream operating segment's VIU, calculated using the estimated discounted future cash flows from the proved plus probable reserves evaluated by Harvest's Independent Reserves Evaluator. The key assumptions required to estimate the recoverable amount are the oil and natural gas prices, and the discount rate. The forecast prices are consistent with what have been used by Harvest's independent reserve evaluator. The discount rate represents management's assessment of the weighted average cost of capital of listed entities that have similar assets based on external sources. A pre-tax discount rate of 10% and the following forward commodity price estimates were used in the goodwill impairment calculation at December 31, 2013:

Year	WTI Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	AECO Gas ($Cdn/Mmbtu)	US$/Cdn$ Exchange Rate
2014	97.50	92.76	4.03	0.95
2015	97.50	97.37	4.26	0.95
2016	97.50	100.00	4.50	0.95
2017	97.50	100.00	4.74	0.95
2018	97.50	100.00	4.97	0.95
Thereafter(1)	+2%/year	+2%/year	+2%/year	0.95

(1) Represents the average escalation percentage in each year after 2018 to the end of reserve life.

Based on the calculation performed using the above assumptions, management did not identify impairment to the Upstream operating segment and the associated goodwill for the year ended December 31, 2013 (2012 and 2011 - $nil). A 200 bps increase in the discount rate would result in a goodwill impairment of approximately $51.9 million, while a 10% decrease in the forward oil price estimates would result in a goodwill impairment of approximately $266.5 million. A 10% decrease in the forward gas or NGL price estimates would not result in any goodwill impairment.

11. Exploration and Evaluation Assets ("E&E")

As at January 1, 2012	$	74.5
Additions		41.1
Dispositions		(0.6)
Unsuccessful exploration and evaluation costs		(22.0)
Transfer to property, plant and equipment		(19.2)
Transfer to assets held for sale		(0.4)

As at December 31, 2012	$	73.4
Additions		16.7
Dispositions		(7.9)
Unsuccessful exploration and evaluation costs		(11.5)
Transfer to property, plant and equipment		(11.3)
As at December 31, 2013	**$**	**59.4**

The Company determined certain E&E costs to be unsuccessful and not recoverable, which were expensed as follows, together with pre-licensing expenses.

	Year Ended December 31					
		2013		2012		2011
Pre-licensing costs	**$**	**0.8**	$	2.9	$	0.5
Unsuccessful E&E costs		**11.5**		22.0		17.8
E&E expense	**$**	**12.3**	$	24.9	$	18.3

12. Long-Term Debt

		December 31, 2013		December 31, 2012		January 1, 2012
Credit facility (note 12a)	**$**	**785.2**	$	491.3	$	355.6
67/8% senior notes due 2017 (US$500 million) (note 12b)		**522.1**		486.4		495.7
21/8% senior notes due 2018 (US$630 million) (note 12c)		**665.7**		−		−
6.40% debentures due 2012 (series D) (note 12d)		−		−		107.1
7.25% debentures due 2013 (series E) (note 12d)		−		331.8		333.3
7.25% debentures due 2014 (series F) (note 12d)		−		60.4		60.6
7.50% debentures due 2015 (series G) (note 12d)		−		239.8		241.0
Promissory note (note 12e)		**12.3**		−		−
Long-term debt outstanding		**1,985.3**		1,609.7		1,593.3
Less current portion		**(12.3)**		(331.8)		(107.1)
Long-term debt	**$**	**1,973.0**	$	1,277.9	$	1,486.2

a) Credit Facility

Effective April 1, 2013, Harvest extended the credit facility maturity date by one year to April 30, 2017. Borrowings under the facility are repayable in full at such date. In addition, the financial covenants for the credit facility agreement were amended to remove the total debt to annualized EBITDA ratio and to add an interest coverage ratio (annualized EBITDA to annualized interest expense). The interest coverage ratio cannot be less than 2.50:1. On October 18, 2013, the credit facility borrowing capacity was increased from $800 million to $1.0 billion. All other terms to the credit facility agreement remain unchanged.

Borrowings under the credit facility are available by way of bankers' acceptances, Canadian prime rate loans, LIBOR based loans, or U.S. base rate loans. At December 31, 2013, Harvest had $788.5 million drawn from the $1.0 billion available under the credit facility (December 31, 2012 - $494.2 million; January 1, 2012 - $358.9 million), of which US$40.0 million were LIBOR based loans (December 31, 2012 - US$90.0 million; January 1, 2012 - $nil). The carrying value of the credit facility includes $3.3 million of deferred financial charges at December 31, 2013 (December 31, 2012 - $2.9 million; January 1, 2012 - $3.3 million). For the year ended December 31, 2013, interest charges on the facility aggregated to $20.3 million (2012 - $17.2 million; 2011 - $5.7 million), reflecting an effective interest rate of 3.0% (2012 and 2011 – 3.0% for both periods).

The credit facility is secured by a first floating charge over all of the assets of Harvest and its restricted subsidiaries plus a first mortgage security interest on the Downstream operation's refinery assets. The most restrictive covenants of Harvest's credit facility include an aggregate limitation of $25 million on financial assistance and/or capital contributions to parties other than Harvest or its restricted subsidiaries, a limitation to carrying on business in countries that are not members of the Organization of Economic Co-operation and Development and a limitation on the payment of distributions to the shareholder in certain circumstances such as an event of default. The credit facility requires standby fees on undrawn amounts and interest on amounts borrowed at varying rates depending on Harvest's ratio of senior debt to its annualized EBITDA. Availability under this facility is subject to the following quarterly financial covenants as defined in the credit facility agreement:

	Covenant	**December 31, 2013**	December 31, 2012	January 1, 2012
Senior debt(1) to annualized EBITDA(2)	3.00 to 1.0 or less	**2.41**	1.10	0.73
Annualized EBITDA(2) to annualized interest expense(3)(4)	2.50 to 1.0 or higher	**3.62**	n/a	n/a
Senior debt(1) to total capitalization(5)	50% or less	**22%**	14%	10%
Total debt(6) to total capitalization(5)	55% or less	**54%**	41%	36%

(1) Senior debt consists of letters of credit of $13.3 million (December 31, 2012 – $8.2 million; January 1, 2012 - $8.7 million), credit facility of $785.2 million (December 31, 2012 - $491.3 million; January 1, 2012 - $355.6 million), guarantees of $32.8 million (December 31, 2012 - $76.6 million; January 1, 2012 - $92.1 million) and risk management contracts liabilities of $0.6 million (December 31, 2012 and January 1, 2012 - $nil) at December 31, 2013.

(2) The measure of Consolidated EBITDA (herein referred to as “annualized EBITDA”) used in Harvest’s credit facility agreement is defined as earnings before finance costs, income tax expense or recovery, DD&A, exploration and evaluation costs, impairment of assets, unrealized gains or losses on risk management contracts, unrealized gains or losses on foreign exchange, gains or losses on disposition of assets and other non-cash items during the last four quarters.

(3) The annualized EBITDA to annualized interest expense ratio was added effective April 1, 2013, under an amendment to the credit facility and the total debt to annualized EBITDA ratio was deleted pursuant to the amendment.

(4) Annualized interest expense is a reference to Consolidated Interest Expense as defined in Harvest’s credit facility agreement and includes all interest expenses and finance charges incurred during the last four quarters.

(5) Total capitalization consists of total debt, related party loans and shareholder’s equity less equity for BlackGold of $457.7 million at December 31, 2013 (December 31, 2012 - $458.6 million; January 1, 2012 - $459.9 million).

(6) Total debt consists of senior debt, convertible debentures and senior notes.

b) 67/8% Senior Notes

On October 4, 2010, Harvest issued US$500 million of 67/8% senior notes for net cash proceeds of US$484.6 million. The senior notes are unsecured with interest payable semi-annually on April 1 and October 1 and mature on October 1, 2017. The senior notes are unconditionally guaranteed by Harvest and all of its wholly-owned subsidiaries that guarantee the revolving credit facility and every future restricted subsidiary that guarantees certain debt. The notes are redeemable at a redemption price equal to 100% of the principal amount of the notes being redeemed plus a make-whole redemption premium, plus accrued and unpaid interest to the redemption date. Harvest may also redeem the notes at any time in the event that certain changes affecting Canadian withholding taxes occur.

There are 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 2.0 to 1. Notwithstanding the interest coverage ratio limitation, the incurrence of additional indebtedness may be permitted under certain incurrence tests. One provision allows Harvest’s incurrence of indebtedness under the credit facility or other future bank debt in an aggregate principal amount not to exceed the greater of $1.0 billion and 15% of total assets. In addition, the covenants of the senior notes restrict the amount of dividends Harvest can pay to shareholders; no dividends have been paid during the year ended December 31, 2013.

c) 21/8% Senior Notes

On May 14, 2013, Harvest issued US$630 million senior unsecured notes due May 14, 2018 with a coupon rate of 21/8% for net proceeds of US$626.1 million. Interest on the 21/8% senior notes is paid semi-annually on May 14 and November 14 of each year.

The senior notes are unconditionally and irrevocably guaranteed by Harvest’s parent company KNOC. A guarantee fee of 0.52% per annum of the principal balance is payable to KNOC semi-annually on May 14 and November 14 of each year. Also see note 28 - Related Party Transactions.

d) Convertible Debentures

On April 2 and April 15, 2013, respectively, Harvest early redeemed the 7.25% Debentures Due 2013 and the 7.25% Debentures Due 2014. Both series of debentures were redeemed at par with the total redemption payment, including all accrued and unpaid interest up to the respective redemption dates being $1,002.9794 per $1,000 principal amount for the 7.25% Debentures Due 2013 and $1,006.5547 per $1,000 principal amount for the 7.25% Debentures Due 2014.

On June 13, 2013, Harvest early redeemed the 7.50% Debentures Due 2015 at par with the total redemption payment, including all accrued and unpaid interest up to the respective redemption dates being $1,002.6712 per $1,000 principal amount.

As a result of the early redemption of all three series of debentures in 2013, Harvest recognized a total gain on redemption of $3.6 million, which has been included in "finance costs" in the consolidated statements of comprehensive loss (see note 22).

On September 19, 2012, Harvest redeemed its 6.40% of convertible debentures at a redemption price of $1,024.90 per $1,000 principal amount for a total amount of $106.8 million. The redemption price was equal to the principal plus all accrued and unpaid interest thereon. Harvest recognized a nominal gain on the redemption in 2012, which has been included in "finance costs" in the consolidated statements of comprehensive income (see note 22). **e) Promissory Note**

During the first quarter of 2013, Downstream entered in to an agreement with a third party to convert $24.2 million of a trade payable to a two-year promissory note. The promissory note bears interest of 3%. The principal and interest are to be repaid in 24 equal installments, which started in January 2013. For the year ended December 31, 2013, interest charges of $0.6 million (2012 and 2011 - $nil) relating to this promissory note were recorded. At December 31, 2013, the current portion of the promissory note is $12.3 million (December 31, 2012 and January 1, 2012 - $nil).

13. Senior Unsecured Credit Facility

On March 14, 2013, Harvest entered into a US$400 million Senior Unsecured Credit Facility. The facility was irrevocably and unconditionally guaranteed by KNOC and would, unless terminated earlier in accordance with its terms, terminate on October 2, 2013. Proceeds of borrowings under the Senior Unsecured Credit Facility were restricted and used to fund the early redemption of the 7.25% Debentures Due 2013 and the 7.25% Debentures Due 2014. Draws from the Senior Unsecured Credit Facility during the second quarter of 2013 were repaid with the proceeds from the issuance of the 21/8% senior notes after which the Senior Unsecured Credit Facility was cancelled.

14. Shareholder's Capital

(a) Authorized
The authorized capital consists of an unlimited number of common shares with no par value and an unlimited number of preferred shares issuable in series.

(b) Number of Common Shares Issued

Outstanding at December 31, 2010	335,535,047
Issued to KNOC at $10.00 per share for Hunt acquisition	50,543,602
Outstanding at December 31, 2013 and 2012 and January 1, 2012	**386,078,649**

15. Capital Structure

Harvest considers its capital structure to be its long term debt, related party loans, and shareholder's equity.

		December 31, 2013		December 31, 2012		January 1, 2012
Credit facility(1)	**$**	**788.5**	$	494.2	$	358.9
67/8% senior notes (US$500 million)(1)(2)		**531.8**		497.5		508.5
21/8% senior notes (US$630 million)(1)(2)		**670.1**		–		–
Related party loans (US$170 million and CAD$80 million)(2) (note 28)		**260.8**		169.1		–
Principal amount of convertible debentures(1)		–		627.2		734.0
	$	**2,251.2**		1,788.0		1,601.4
Shareholder's equity		**1,939.2**		2,691.9		3,453.7
	$	**4,190.4**	$	4,479.9	$	5,055.1

(1) Excludes capitalized financing fees
(2) Face value converted at the period end exchange rate

Harvest's primary objective in its management of capital resources is to have access to capital to fund its financial obligations as well as future operating and capital activities. Harvest monitors its capital structure and makes adjustments according to market conditions to remain flexible while meeting these objectives. Accordingly, Harvest may adjust its capital spending programs, issue equity, issue new debt or repay existing debt.

Harvest evaluates its capital structure using the same financial covenant ratios as the ones externally imposed under the Company's credit facility (see note 12a). The Company continually monitors its credit facility covenants and actively takes steps, such as reduce borrowings, increase capitalization, amending or renegotiating covenants as and when required, to ensure compliance. Harvest was in compliance with all debt covenants at December 31, 2013 and the prior period.

On December 30, 2013, Harvest signed a five year $200 million subordinated loan agreement with KNOC (see note 28) to increase flexibility in the Company's capital structure. Harvest intends to fund capital and operating requirements using proceeds drawn from this loan agreement. The Company borrowed $80 million under such loan agreement on December 30, 2013. Had Harvest fully drawn down the $200 million and applied the proceeds against its borrowings under the credit facility, the "total debt to total capitalization" covenant ratio would have been 51% as at December 31, 2013. Through active capital management, Harvest does not expect to breach this covenant.

16. Financial Instruments

a) Fair Values

Financial instruments of Harvest consist of cash, accounts receivable, accounts payable and accrued liabilities, borrowings under the credit facility, risk management contracts, promissory note, senior notes, related party loans and long term liability. Cash and risk management contracts are the only financial instruments that are measured at fair value on a recurring basis. Harvest classifies the fair value of these transactions according to the fair value hierarchy based on the amount of observable inputs used to value the instrument.

During the year ended December 31, 2013, there were no transfers among Levels 1, 2 and 3.

	December 31, 2013		Fair Value Measurements	
	Carrying Value	Fair Value	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)
Financial assets				
Loans and Receivables				
Accounts receivable (note 16b)	$ 168.9	$ 168.9	$ –	$ 168.9
Held for Trading				
Risk management contracts	0.3	0.3	–	0.3
Total Financial Assets	$ 169.2	$ 169.2	$ –	$ 169.2
Financial Liabilities				
Held for Trading				
Risk management contracts	$ 0.6	$ 0.6	$ –	$ 0.6
Measured at Amortized Cost				
Accounts payable and accrued liabilities (note 16b)	258.3	258.3	–	258.3
Credit facility	785.2	788.5	–	788.5
67/8% senior notes	522.1	577.7	–	577.7
21/8% senior notes	665.7	653.2	653.2	–
Promissory note	12.3	12.3	–	12.3
Related party loans	259.6	242.1	–	242.1
Long-term liability	69.2	60.7	–	60.7
Total Financial Liabilities	$ 2,573.0	$ 2,593.4	$ 653.2	$ 1,940.2

	December 31, 2012 (*Restated*)*		Fair Value Measurements	
	Carrying Value	Fair Value	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)
Financial assets				
Loans and Receivables				
Accounts receivable (note 16b)	$ 175.6	$ 175.6	$ –	$ 175.6
Held for Trading				
Cash	7.6	7.6	7.6	–
Risk management contracts	1.8	1.8	–	1.8
Total Financial Assets	$ 185.0	$ 185.0	$ 7.6	$ 177.4
Financial Liabilities				
Measured at Amortized Cost				
Accounts payable and accrued liabilities (note 16b)	373.0	373.0	–	373.0
Credit facility	491.3	494.2	–	494.2
67/8% senior notes	486.4	555.3	–	555.3
Convertible debentures	632.0	644.0	644.0	–
Related party loan	172.1	172.1	–	172.1
Long-term liability	7.7	7.7	–	7.7
Total Financial Liabilities	$ 2,162.5	$ 2,246.3	$ 644.0	$ 1,602.3

*See Note 3

	January 1, 2012 (*Restated*)*		Fair Value Measurements	
	Carrying Value	Fair Value	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)
Financial assets				
Loans and Receivables				
Accounts receivable (note 16b)	$ 212.3	$ 212.3	$ –	$ 212.3
Held for Trading				
Cash	6.6	6.6	6.6	–
Risk management contracts	20.2	20.2	–	20.2
Total Financial Assets	$ 239.1	$ 239.1	$ 6.6	$ 232.5
Financial Liabilities				
Measured at Amortized Cost				
Accounts payable and accrued liabilities (note 16b)	462.2	462.2	–	462.2
Credit facility	355.6	358.9	–	358.9
67/8% senior notes	495.7	523.1	–	523.1
Convertible debentures	742.0	752.5	752.5	–
Total Financial Liabilities	$ 2,055.5	$ 2,096.7	$ 752.5	$ 1,344.2

*See Note 3

Non-derivative financial instruments
Due to the short term maturities of accounts receivable, accounts payable and accrued liabilities and promissory note, their carrying values approximate their fair values.

The credit facility bears floating market rate, thus, the fair value approximates the carrying value (excluding deferred financing charges). The carrying value of the credit facility includes $3.3 million of deferred financing charges at December 31, 2013 (December 31, 2012 – $2.9 million; January 1, 2012 – $3.3 million).

The fair value of the 21/8% senior notes was based on the quoted market price of the notes on the Singapore Exchange as at December 31, 2013 (Level 1), which includes the benefit of the guarantee offered by KNOC. The fair value of the convertible debentures was based on the quoted market price on the Toronto Stock Exchange as at December 31, 2012 and January 1, 2012 (Level 1). The fair value of the 67/8% senior notes was estimated based on the period end trading price of the notes on the secondary market (Level 2).

The fair values of the related party loans and long-term liability are estimated by discounting the future interest and principal payments using the current market interest rates of instruments with similar terms. At December 31, 2013, the rate used in determining the fair values of the related party loans and long-term liability was 7.0% (December 31, 2012 – 4.6% and 4.5%, respectively; January 1, 2012 - nil).

Derivative financial instruments

Harvest enters into risk management contracts with various counterparties, principally financial institutions with investment grade credit ratings. The fair values of the risk management contracts are determined based on the quoted forward prices of similar transactions observable in active markets as at December 31, 2013. The fair values of the risk management contracts are net of a credit valuation adjustment attributable to derivative counterparty default risk or the Company's own default risk. The changes in counterparty credit risk had no material effect on the hedge effectiveness assessment for derivatives designated in the hedging relationship and other financial instruments recognized at fair value. Derivative financial instruments carried at fair value are as follows:

	December 31, 2013		December 31, 2012		January 1, 2012	
	Asset	Liability	Asset	Liability	Asset	Liability
Natural gas swap	**$ 0.2**	**$ –**	$ 1.8	$ –	$ –	$ –
Crude oil price swap	–	–	–	–	19.7	–
Power swap	**0.1**	**(0.6)**	–	–	0.5	–
	$ 0.3	**$ (0.6)**	$ 1.8	$ –	$ 20.2	$ –

b) Financial Assets and Financial Liabilities Subject to Offsetting

The following table presents the recognized financial instrument that are offset, or subject to enforceable master netting arrangements or other similar agreements but not offset, as at December 31, 2013 and 2012 and January 1, 2012, and shows in the "net" column what the net impact would be on Harvest's statement of financial position if all set-off rights was exercised.

		Amounts offset			**Related financial instruments that are not offset**	
	Notes	**Gross assets (liabilities)**	**Gross assets (liabilities) offset**	**Net amount presented**		**Net**
December 31, 2013						
Financial assets						
Account receivable	(a)(b)	$ **197.5**	$ **(189.7)**	$ **7.8**	$ **-**	$ **7.8**
Risk management contracts	(c)	**0.3**	**-**	**0.3**	**(0.1)**	**0.2**
		$ **197.8**	**$ (189.7)**	**$ 8.1**	**$ (0.1)**	**$ 8.0**
Financial Liabilities						
Account payable and accrued liabilities	(a)(b)	$ **(189.7)**	$ **189.7**	$ **-**	$ **-**	$ **-**
Risk management contracts	(c)	**(0.6)**	**-**	**(0.6)**	**0.1**	**(0.5)**
		$ **(190.3)**	**$ 189.7**	**$ (0.6)**	**$ 0.1**	**$ (0.5)**
December 31, 2012						
Financial assets						
Account receivable	(a)(b)	$ 237.2	$ (237.2)	$ -	$ -	$ -
Risk management contracts	(c)	1.8	-	1.8	-	1.8
		$ 239.0	$ (237.2)	$ 1.8	$ -	$ 1.8
Financial Liabilities						
Account payable and accrued liabilities	(a)(b)	$ (267.5)	$ 237.2	$ (30.3)	$ -	$ (30.3)
Risk management contracts	(c)	-	-	-	-	-
		$ (267.5)	$ 237.2	$ (30.3)	$ -	$ (30.3)
January 1, 2012						
Financial assets						
Account receivable	(a)(b)	$ 142.8	$ (142.8)	$ -	$ -	$ -
Risk management contracts	(c)	20.2	-	20.2	-	20.2
		$ 163.0	$ (142.8)	$ 20.2	$ -	$ 20.2
Financial Liabilities						
Account payable and accrued liabilities	(a)(b)	$ (185.9)	$ 142.8	$ (43.1)	$ -	$ (43.1)
Risk management contracts	(c)	-	-	-	-	-
		$ (185.9)	$ 142.8	$ (43.1)	$ -	$ (43.1)

(a) Standard terms of the supply and off take ("SOA") agreement include provision allowing settlement of payments in the normal course of business.
(b) Various master netting agreements with counterparties that allow net settlement of payments in the normal course of business.
(c) Harvest entered into derivative transactions under International Swaps and Derivatives Association ("ISDA") master netting agreements. In general, under such agreements the amounts owed by each counterparty on a single day in respect of all transactions outstanding in the same currency are aggregated into a single net amount that is payable by one party to the other. In certain circumstances – e.g. When credit event such as default occurs, all outstanding transactions under the agreement are terminated, the termination value is assessed and only a single net amount is payable is settlement of all transactions. The ISDA agreements do not meet the criteria for offsetting in the statement of financial position as Harvest does not have currently enforceable right to offset recognized amounts because the rights to offset is enforceable only on the occurrence of future events such as a default on the bank loan or other credit events.

c) Risk Exposure

Harvest manages its exposures to financial risks in accordance with its risk management profile with the objective to support the Company's cash flow requirements and to deliver financial targets. Harvest is exposed to market risks resulting from fluctuations in commodity prices, currency 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, counterparty risk from price risk management contracts and to liquidity risk relating to the Company's debt. Management monitors and measures these risks and report to the Board of Directors on a regular basis. Risk management targets, such as hedging ratio, hedge contracts, prices and duration of contracts are reviewed and approved by the Board at least annually.

(i) *Risk Management Contracts*

The Company at times enters into natural gas, crude oil, electricity and foreign exchange contracts to reduce the volatility of cash flows from some of its forecast sales and purchases, and when allowable, will designate these contracts as cash flow hedges. These derivative contracts are entered for periods consistent with the underlying hedged transactions. Under hedge accounting, the effective portion of the unrealized gains and losses is included in OCL. The effective portion of the realized gains and losses is removed from AOCL and included in petroleum, natural gas, and refined product sales (see note 16 and 20). The ineffective portion of the unrealized and realized gains and losses are recognized in the consolidated statement of comprehensive loss.

Risk management contracts (gains) losses recorded to income include the ineffective portion of the gains or losses on the derivative contracts designated as cash flow hedges, the gains or losses on the derivatives that were not designated as hedges and the gains or losses subsequent to the discontinuation of hedge accounting on the previously designated derivatives:

	Year Ended December 31								
	2013			2012			2011		
	Realized gains	**Unrealized losses**	**Total**	Realized (gains) losses	Unrealized losses	Total	Realized (gains) losses	Unrealized (gains) losses	Total
Power	**$ (3.1)**	**$ 0.5**	**$ (2.6)**	$ –	$ –	$ –	$ (7.7)	$ 1.0	$ (6.7)
Crude Oil	**(0.4)**	–	**(0.4)**	(2.1)	1.1	(1.0)	1.7	(1.7)	–
Currency	**(1.4)**	–	**(1.4)**	0.5	–	0.5	–	–	–
	$ (4.9)	**$ 0.5**	**$ (4.4)**	$ (1.6)	$ 1.1	$ (0.5)	(6.0)	(0.7)	$ (6.7)

The following is a summary of Harvest's risk management contracts outstanding at December 31, 2013:

Contracts Designated as Hedges

Contract Quantity	Type of Contract	Term	Contract Price	Fair Value
36,750 GJ/day	AECO swap	Jan – Dec 2014	$3.71/GJ	$ 0.2

Contracts Not Designated as Hedges

Contract Quantity	Type of Contract	Term	Contract Price	Fair Value
30 MWh	AESO power swap	Jan – Dec 2014	$55.29/MWh	$ (0.5)

(ii) Credit Risk

Upstream Accounts Receivable

Accounts receivable in Harvest's Upstream operations are due from crude oil and natural gas purchasers as well as joint venture partners 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 of the counterparty; however, if external ratings are not available, Harvest performs an internal credit review based on the purchaser's past financial performance. Credit is allocated to a counterparty dependent on the external and internal credit rating, and if required parent guarantees, letter of credit or prepayments are requested. The credit risk associated with joint venture partners is mitigated by reviewing the credit history of partners and requiring some partners to provide cash prior to incurring significant capital costs on their behalf. Additionally, most agreements have a provision enabling Harvest to use the proceeds from the sale of production that would otherwise be taken in kind by the partner to offset amounts owing from the partner that is in default. Generally, the only instances of impairment are when a purchaser or partner is facing bankruptcy or extreme financial distress.

Risk Management Contract Counterparties

Harvest is exposed to credit risk from the counterparties to its risk management contracts. This risk is managed by diversifying Harvest's risk management portfolio among a number of counterparties limited to lenders in its syndicated credit facility; Harvest has no history of losses with these counterparties.

Downstream Accounts Receivable

The SOA exposes Harvest to the credit risk of Macquarie Energy Canada Ltd. ("Macquarie") as all feedstock purchases and the majority of product sales are made with Macquarie. This credit risk is mitigated by the amounts owing to Macquarie for feedstock purchases that are offset against amounts receivable from Macquarie for product sales with the balance being net settled. The SOA also requires both Harvest and Maquarie's parent, Macquarie Bank Ltd, to provide reciprocal guarantees of US$75 million to each other in order to mitigate the risk of either counterparty being unable to settle a net payable amount. At December 31, 2013, Harvest is in a net receivable position with Macquarie and the outstanding balance is included in the trade receivable table below.

Harvest's maximum exposure to credit risk relating to the above classes of financial assets at December 31, 2013 and 2012 and January 1, 2012 is the carrying value of accounts receivable. The tables below provide an analysis of Harvest's current and past due but not impaired receivables.

	December 31, 2013				
		Overdue AR			
	Current AR	**≤ 30 days**	**> 30 days, ≤ 60 days**	**> 60 days, ≤ 90 days**	**> 90 days**
Upstream accounts receivable[1]	$ 111.2	$ 1.1	$ 0.4	$ 0.1	$ 2.1
Downstream accounts receivable[1]	44.8	–	5.9	1.6	1.7
	$ 156.0	**$ 1.1**	**$ 6.3**	**$ 1.7**	**$ 3.8[2]**

(1) Net of payables subject to master netting arrangements or other similar agreements. See note 16(b).

(2) Net of $2.5 million of allowance for doubtful accounts.

	December 31, 2012				
		Overdue AR			
	Current AR	≤ 30 days	> 30 days, ≤ 60 days	> 60 days, ≤ 90 days	> 90 days
Upstream accounts receivable[1]	$ 114.9	$ 0.7	$ 0.4	$ 0.5	$ 5.5
Downstream accounts receivable[1]	44.2	–	7.0	1.5	0.9
	$ 159.1	$ 0.7	$ 7.4	$ 2.0	$ 6.4[2]

(1) Net of payables subject to master netting arrangements or other similar agreements. See note 16(b).
(2) Net of $4.0 million of allowance for doubtful accounts.

	January 1, 2012				
		Overdue AR			
	Current AR	≤ 30 days	> 30 days, ≤ 60 days	> 60 days, ≤ 90 days	> 90 days
Upstream accounts receivable(1)	$ 146.1	$ 1.3	$ 0.6	$ 1.2	$ 4.0
Downstream accounts receivable(1)	50.7	6.1	1.7	0.2	0.4
	$ 196.8	$ 7.4	$ 2.3	$ 1.4	$ 4.4(2)

(1) Net of payables subject to master netting arrangements or other similar agreements. See note 16(b).
(2) Net of $3.3 million of allowance for doubtful accounts.

(iii) Liquidity Risk

Harvest is exposed to liquidity risk due to the Company's accounts payables and accrued liabilities, risk management contracts liability, borrowings under its credit facility, senior notes, promissory note, related party loans and long long-term liability. This risk is mitigated by managing the maturity dates on the Company's obligations, utilizing the undrawn borrowing capacity in the credit facility and related party loan with KNOC, complying with covenants and managing the Company's cash flow by entering into price risk management contracts. Additionally, when Harvest enters into price risk management contracts it selects counterparties that are also lenders in its syndicated credit facility thereby using the security provided in the credit agreement and eliminating the requirement for margin calls and the pledging of collateral. Majority of the financial liabilities are an integral part of Harvest's capital structure which is monitored and managed as discussed in note 15.

In addition to the guarantee provided to Macquarie, at December 31, 2012, Harvest also provided guarantees of $2.0 million for Downstream product purchases (January 1, 2012 - $15.8 million). Harvest did not provide any guarantees for product purchases as at December 31, 2013.

The following tables provide an analysis of Harvest's financial liability maturities based on the remaining terms of its liabilities including the related interest charges as at December 31, 2013 and 2012, and January 1, 2012:

	December 31, 2013				
	≤1 year	**>1 year ≤3 years**	**>3 years ≤5 years**	**>5 years**	**Total**
Accounts payable and accrued liabilities(1)	$ 258.3	$ –	$ –	$ –	$ 258.3
Credit facility and interest	25.8	51.7	789.2	–	866.7
67/8% senior notes and interest	36.5	73.1	568.4	–	678.0
21/8% senior notes and interest	14.2	28.5	691.4	–	734.1
Promissory note and interest	12.5	–	–	–	12.5
Related party loans and interest	–	–	316.0	–	316.0
Long-term liability	–	21.8	19.3	48.2	89.3
Risk management contracts liability	0.6	–	–	–	0.6
	$ 347.9	**$ 175.1**	**$ 2,384.3**	**$ 48.2**	**$ 2,955.5**

(1) Net of receivables subject to master netting arrangements or other similar agreements. See note 16(b).

	December 31, 2012 (*Restated*)*				
	≤1 year	**>1 year ≤3 years**	**>3 years ≤5 years**	**>5 years**	**Total**
Accounts payable and accrued liabilities(1)	$ 373.0	$ –	$ –	$ –	$ 373.0
Credit facility and interest	13.9	27.9	498.8	–	540.6
Convertible debentures and interest	370.6	322.5	–	–	693.1
67/8% senior notes and interest	34.2	68.4	557.3	–	659.9
Related party loan and interest	–	–	206.4	–	206.4
Long-term liability	–	3.9	0.9	2.9	7.7
	$ 791.7	$ 422.7	$ 1,263.4	$ 2.9	$ 2,480.7

*See Note 3

(1) Net of receivables subject to master netting arrangements or other similar agreements. See note 16(b).

	January 1, 2012 (*Restated*)*				
	≤1 year	>1 year ≤3 years	>3 years ≤5 years	>5 years	Total
Accounts payable and accrued liabilities(1)	$ 462.2	$ –	$ –	$ –	$ 462.2
Credit facility and interest	5.6	11.3	360.7	–	377.6
Convertible debentures and interest	158.6	449.1	244.0	–	851.7
67/8% senior notes and interest	35.0	69.9	69.9	534.7	709.5
	$ 661.4	$ 530.3	$ 674.6	$ 534.7	$ 2,401.0

*See Note 3

(1) Net of receivables subject to master arrangements or other similar agreements. See note 16(b).

(iv) Market Risks and Sensitivity Analysis

Interest rate risk

Harvest is exposed to interest rate risk on its bank borrowings as interest rates are determined in relation to floating market rates plus an incremental charge based on the Company's senior debt to annualized EBITDA. Harvest's 67/8% and 21/8% senior notes and related party loans have fixed interest rates and therefore do not have any additional interest rate risk. Harvest manages its interest rate risk by targeting appropriate levels of debt relative to its expected cash flow from operations.

If the interest rate applicable to Harvest's bank borrowings at December 31, 2013 increased or decreased by approximately 30 basis points with all other variables held constant, pre-tax income for the year would change by $2.3 million (2012 – $1.4 million; 2011 - $1.0 million) as a result of change in interest expense on variable rate borrowings under the credit facility.

Currency exchange rate risk

Harvest is exposed to the risk of changes in the U.S. dollar exchange rate on its U.S. dollar denominated revenues. In addition, Harvest's 67/8% and 21/8% senior notes, related party loan from ANKOR and LIBOR based loans are denominated in U.S. dollars, collectively US$1.3 billion (2012 - $760 million; 2011 - $500 million). Interest on such debt is also payable in U.S. dollars and accordingly, the future cash payments of the principal and interest obligations will be sensitive to fluctuations in the U.S. dollars relative to the Canadian dollars.

Harvest's Downstream operations operate with a U.S. dollar functional currency which gives rise to currency exchange rate risk on the Company's Canadian dollar denominated monetary assets and liabilities such as Canadian dollar bank accounts, accounts receivable and payable, and defined benefit obligations. 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 receipts.

If the U.S. dollar strengthened or weakened by 10% relative to the Canadian dollar, the impact on pre-tax income and other comprehensive income due to the translation of financial instruments held at December 31 would be as follows:

	December 31, 2013		December 31, 2012		January 1, 2012	
	Increase (decrease) in pre-tax income	**Increase (decrease) in OCI before tax**	Increase (decrease) in pre-tax income	Increase (decrease) in OCI before tax	Increase (decrease) in pre-tax income	Increase (decrease) in OCI before tax
10% strengthening in U.S. dollar relative to Canadian dollar	$ (50.6)	$ (64.3)	$ (1.2)	$ (46.5)	$ (19.9)	$ (34.8)
10% weakening in U.S. dollar relative to Canadian dollar	$ 50.6	$ 64.3	$ 1.2	$ 46.5	$ 19.9	$ 34.8

(1) The sensitivity to net income and other comprehensive income is done independently.

Commodity Price Risk

Harvest is exposed to natural gas and crude oil price movements as part of its normal business operations. The Company uses price risk management contracts to protect a portion of the Company's future cash flows and net income against unfavorable movements in commodity prices. These contracts are recorded on the consolidated statement of financial position at their fair value as of the reporting date. These fair values are generally determined as the difference between the stated fixed price of the contract and an expected future price of the commodity. Variances in expected future prices expose Harvest to commodity price risk as changes will result in a gain or loss that Harvest will realize on settlement of these contracts. This risk is mitigated by continuously monitoring the effectiveness of these contracts.

If the following changes in expected forward prices were applied to the fair value of risk management contracts in place at December 31, 2013 and 2012, and January 1, 2012, the pre-tax impact would be as follows:

	December 31, 2013	
	Increase (decrease) in pre-tax income	**Increase (decrease) in OCI before tax**
Forward price of natural gas – 10% increase	**$ –**	**$ (5.0)**
Forward price of natural gas – 10% decrease	**$ –**	**$ 5.0**
Forward price of electricity – 10% increase	**$ 1.4**	**$ –**
Forward price of electricity – 10% decrease	**$ (1.4)**	**$ –**

	December 31, 2012	
	Increase (decrease) in pre-tax income	Increase (decrease) in OCI before tax
Forward price of natural gas – 10% increase	$ –	$ (1.2)
Forward price of natural gas – 10% decrease	$ –	$ 1.2

	January 1, 2012	
	Increase (decrease) in pre-tax income	Increase (decrease) in OCI before tax
Forward price of crude oil – 10% increase	$ (1.0)	$ (18.5)
Forward price of crude oil – 10% decrease	$ 0.6	$ 11.4

17. Provisions

	Upstream	**BlackGold**	**Downstream**	**Total**
Decommissioning liabilities at January 1, 2012	$ 664.4	$ 1.5	$ 14.6	$ 680.5
Liabilities incurred	9.9	15.8	–	25.7
Settled during the period	(18.4)	(0.2)	–	(18.6)
Revisions (change in estimated timing and costs)	72.8	2.6	1.2	76.6
Disposals	(27.4)	–	–	(27.4)
Accretion	19.9	0.1	0.4	20.4
Transfers to assets held for sale	(11.9)	–	–	(11.9)
Decommissioning liabilities at December 31, 2012	$ 709.3	$ 19.8	$ 16.2	$ 745.3
Environmental remediation at December 31, 2012	6.6	–	–	6.6
Other provisions at December 31, 2012	3.5	–	–	3.5
Less current portion	(28.1)	–	–	(28.1)
Non-current provisions at December 31, 2012	$ 691.3	$ 19.8	$ 16.2	$ 727.3
Decommissioning liabilities at December 31, 2012	$ 709.3	$ 19.8	$ 16.2	$ 745.3
Liabilities incurred	8.6	14.9	–	23.5
Settled during the period	(18.6)	(0.1)	–	(18.7)
Revisions (change in estimated timing and costs)	22.9	(1.1)	–	21.8
Disposals	(33.6)	–	–	(33.6)
Accretion	20.8	0.8	0.5	22.1
Decommissioning liabilities at December 31, 2013	$ 709.4	$ 34.3	$ 16.7	$ 760.4
Environmental remediation at December 31, 2013	6.7	–	–	6.7
Other provisions at December 31, 2013	3.5	–	–	3.5
Less current portion	(39.1)	–	–	(39.1)
Non-current provisions at December 31, 2013	**$ 680.5**	**$ 34.3**	**$ 16.7**	**$ 731.5**

Harvest estimates the total undiscounted amount of cash flows required to settle its decommissioning and environmental remediation liabilities to be approximately $1.6 billion at December 31, 2013 (December 31, 2012 - $1.8 billion; January 1, 2012 - $1.4 billion), which will be incurred between 2014 and 2074. A risk-free discount rate of 3.0% (December 31, 2012 and January 1, 2012 - 3.0%) and inflation rate of 1.7% (December 31, 2012 and January 1, 2012 - 1.7%) were used to calculate the fair value of the decommissioning and environmental remediation liabilities. The actual decommissioning and environmental remediation costs will ultimately depend upon future market prices for the necessary decommissioning and remediation work required, which will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning is likely to depend on when the fields cease to produce at economically viable rates. This in turn will depend upon future oil and gas prices, which are inherently uncertain.

Harvest's other provisions relates to legal claims against Harvest and their estimated settlement amounts. In addition to these claims, Harvest is defendant and plaintiff in a number of other legal actions that arise in the normal course of business and the company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial statements.

18. Long-Term Liability

On May 30, 2012, Harvest amended certain aspects of its BlackGold oil sands project engineering, procurement and construction ("EPC") contract, including revising the compensation terms from a lump sum price to a cost reimbursable price and confirming greater Harvest control over project execution. Harvest and the EPC contractor also agreed to apply the cumulative progress payments made under the lump sum contract and the remaining deposit of $24.4 million as at May 30, 2012 towards costs incurred to that date.

Under the EPC contract, a maximum of approximately $101 million of the EPC costs will be paid in equal installments, without interest, over 10 years commencing on the completion of the EPC work in 2014. The liability is considered a financial liability and is initially recorded at fair value, which is estimated as the present value of all future cash payments discounted using the prevailing market rate of interest for similar instruments. As at December 31, 2013, Harvest recognized a total liability of $76.2 million (December 31, 2012 – $4.7 million; January 1, 2012 – $nil) using a discount rate of 4.5% (December 31, 2012 – 4.5%; January 1, 2012 – nil) of which $9.6 million (December 31, 2012 and January 1, 2012 – $nil) is payable within a year and has been included with accounts payable and accrued liabilities.

Also included in long-term liability is an accrual related to Harvest's long term incentive program of $2.6 million (December 31, 2012 – $3.0 million; January 1, 2012 – $1.9 million) as well as deferred credits of $0.3 million (December 31, 2012 – $0.5 million; January 1, 2012 – $0.8 million).

19. Income Taxes

	Year Ended December 31		
	2013	2012 *(Restated)**	2011 *(Restated)**
Current income tax expense	**$ –**	$ –	$ 0.1
Deferred income tax ("DIT") recovery	**(64.2)**	(81.6)	(30.1)
	$ (64.2)	$ (81.6)	$ (30.0)

*See Note 3.

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

	Year Ended December 31		
	2013	2012 *(Restated)**	2011 *(Restated)**
Loss before income tax	**$ (846.1)**	$ (802.6)	$ (135.4)
Combined Canadian federal and provincial statutory income tax rate	**27.69%**	27.65%	28.08%
Computed income tax recovery at statutory rates	**(234.3)**	(221.9)	(38.0)
Increased expense (recovery) resulting from the following:			

Difference between current and expected tax rates		**60.4**		56.3		13.9
Foreign exchange impact not recognized in income		**15.8**		(6.7)		7.8
Amended returns and pool balances		**(0.3)**		6.1		4.9
Reversal of previously recognized temporary differences		**75.0**		52.4		(12.7)
Non-deductible expenses (recoveries)		**(11.0)**		4.6		(3.5)
Other		**2.6**		(0.1)		(2.4)
Non-taxable portion of capital loss		**–**		–		–
		(91.8)		(109.3)		(30.0)
Income tax credit receivable written-off		**27.6**		27.7		–
Income tax recovery	**$**	**(64.2)**	$	(81.6)	$	(30.0)

*See Note 3.

The change in the applicable tax rate for the year ended December 31, 2013 from the previous year is due to an increase in the provincial component of the tax rate.

Movements in the DIT asset (liability) are as follows:

		PP&E		Decommissioning liabilities		Non-capital tax losses		Other		Total deferred asset (liability)
At January 1, 2012	$	(605.3)	$	172.4	$	375.0	$	3.0	$	(54.9)
Recognized in profit or loss		282.3		19.2		(184.1)		(8.1)		109.3
Recognized in other comprehensive loss		–		–		–		6.7		6.7
At December 31, 2012	$	(323.0)	$	191.6	$	190.9	$	1.6	$	61.1
Recognized in profit or loss		28.4		0.8		57.3		5.3		91.8
Recognized in other comprehensive loss		–		–		–		(4.1)		(4.1)
At December 31, 2013	**$**	**(294.6)**	**$**	**192.4**	**$**	**248.2**	**$**	**2.8**	**$**	**148.8**

DIT assets are recognized to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax losses can be utilized. As at December 31, 2013, Harvest had approximately $1.5 billion (December 31, 2012 - $1.1 billion; January 1, 2012 - $1.6 billion) of carry-forward tax losses and approximately $3.5 billion (December 31, 2012 - $3.5 billion; January 1, 2012 - $2.8 billion) of tax pools that would be available to offset against future taxable profit. The carry-forward losses will expire between the years 2024 and 2033. Based on management's best estimate of the forecasted future taxable profit of the Company, management believes that there is not sufficient evidence to recognize $713.8 million (December 31, 2012 - $300.0 million; January 1, 2012 - $nil) of the carry-forward tax losses within its Downstream operations as it is not probable that sufficient future taxable profit will be available to utilize these losses. Consequently $142.7 million (December 31, 2012 - $60.0 million; January 1, 2012 - $nil) of DIT assets have not been recognized as at December 31, 2013 which related to carry-forward tax losses that will expire between the years 2026 and 2032.

As at December 31, 2013, Harvest had a contingent liability relating to an unsettled dispute with the Canada Revenue Agency. This contingent liability has not been provided for in the consolidated statement of financial position as the Company has assessed that it is possible but not probable that a payment will be necessary. The range of possible payment is estimated to be between $3.6 million to $7.1 million.

20. Revenues

	Year Ended December 31					
		2013		2012		2011
Petroleum and natural gas sales, net of royalties	**$**	**943.9**	$	999.3	$	1,100.8
Refined products sales		**4,416.9**		4,752.1		3,302.3
Effective portion of realized crude oil hedges		**3.9**		29.6		(9.4)
	$	**5,364.7**	$	5,781.0	$	4,393.7

21. Operating and General and Administrative ("G&A") Expenses

	Year Ended December 31								
	Upstream			Downstream			Total		
Operating expenses	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Power and purchased energy	**$ 89.1**	$ 79.6	$ 83.1	**$ 106.7**	$ 140.7	$ 117.3	**$ 195.8**	$ 220.3	$ 200.4
Well servicing	**49.9**	56.0	61.6	–	–	–	**49.9**	56.0	61.6
Repairs and maintenance	**51.7**	57.0	60.0	**23.6**	26.4	20.4	**75.3**	83.4	80.4
Lease rentals and property taxes	**37.3**	38.3	34.7	–	–	–	**37.3**	38.3	34.7
Salaries and benefits	**31.8**	31.5	28.1	**71.3**	67.6	59.8	**103.1**	99.1	87.9
Professional and consultation fees	**15.3**	19.3	19.4	**3.9**	5.7	4.5	**19.2**	25.0	23.9
Chemicals	**18.7**	18.0	15.4	–	–	–	**18.7**	18.0	15.4
Processing fees	**36.8**	33.4	22.6	–	–	–	**36.8**	33.4	22.6
Trucking	**13.9**	16.3	13.3	–	–	–	**13.9**	16.3	13.3
Other	**1.1**	9.6	12.2	**27.6**	22.2	24.6	**28.7**	31.8	36.8
	$ 345.6	$ 359.0	$ 350.4	**$ 233.1**	$ 262.6	$ 226.6	**$ 578.7**	$ 621.6	$ 577.0

	Year Ended December 31		
General and administrative expenses	**2013**	2012	2011
Salaries and benefits	**$ 60.2**	$ 64.8	$ 59.5
Professional and consultation fees	**13.9**	10.8	7.9
Other	**15.0**	13.3	18.6
G&A capitalized and recovery	**(20.4)**	(23.3)	(23.4)
	$ 68.7	$ 65.6	$ 62.6

22. Finance Costs

	Year Ended December 31		
	2013	2012	2011
Interest and other finance charges	**$ 95.3**	$ 103.9	$ 94.1
Accretion of decommissioning and environmental remediation liabilities	**22.3**	20.7	23.6
Gain on redemption of convertible debentures	**(3.6)**	(0.1)	–
Less: capitalized interest	**(19.8)**	(13.5)	(8.6)
	$ 94.2	$ 111.0	$ 109.1

23. Foreign Exchange

	Year Ended December 31		
	2013	2012	2011
Realized losses (gains) on foreign exchange	**$ 3.4**	$ (0.1)	$ (6.6)
Unrealized losses (gains) on foreign exchange	**40.8**	(1.2)	2.6
	$ 44.2	$ (1.3)	$ (4.0)

24. Supplemental Cash Flow Information

	Year Ended December 31		
	2013	2012 *(Restated)**	2011 *(Restated)**
Source (use) of cash:			
Accounts receivable	**$ 6.7**	$ 36.7	$ 1.7
Prepaid expenses and long-term deposit	**6.1**	18.2	42.2
Inventories	**29.2**	(19.8)	14.5
Accounts payable and accrued liabilities	**(114.7)**	(89.2)	103.3
Net changes in non-cash working capital	**(72.7)**	(54.1)	161.7
Changes relating to operating activities	**(70.6)**	11.0	51.1
Changes relating to investing activities	**21.6**	(63.8)	108.7
Promissory note (note 12e)	**(24.2)**	–	–
Add: Non-cash changes	**0.5**	(1.3)	1.9
	$ (72.7)	$ (54.1)	$ 161.7

*See Note 3.

25. Accumulated Other Comprehensive Loss ("AOCL")

	Foreign Currency Translation Adjustment	Designated Cash Flow Hedges, Net of Tax	Actuarial Loss, Net of Tax	Total
Balance at December 31, 2010 *(Restated)**	$ (45.9)	$ (5.0)	$ (2.6)	$ (53.5)
Reclassification to net income of losses on cash flow hedges	−	7.1	−	7.1
Gains on derivatives designated as cash flow hedges, net of tax	−	12.3	−	12.3
Actuarial loss, net of tax	−	−	(4.2)	(4.2)
Losses on foreign currency translation	21.5	−	−	21.5
Balance at December 31, 2011 *(Restated)**	$ (24.4)	$ 14.4	$ (6.8)	$ (16.8)
Reclassification to net income of gains on cash flow hedges	−	(22.4)	−	(22.4)
Gains on derivatives designated as cash flow hedges, net of tax	−	9.2	−	9.2
Actuarial loss, net of tax	−	−	(9.9)	(9.9)
Losses on foreign currency translation	(17.7)	−	−	(17.7)
Balance at December 31, 2012 *(Restated)**	$ (42.1)	$ 1.2	$ (16.7)	$ (57.6)
Reclassification to net income of gains on cash flow hedges	−	(2.8)	−	(2.8)
Gains on derivatives designated cash flow hedges, net of tax	−	1.7	−	1.7
Actuarial gain, net of tax	−	−	18.1	18.1
Gains on foreign currency translation	7.9	−	−	7.9
Balance at December 31, 2013	**$ (34.2)**	**$ 0.1**	**$ 1.4**	**$ (32.7)**

*See Note 3.

The following table summarizes the impacts of the cash flow hedges on the OCL:

	Year Ended December 31					
	After - tax			Pre - tax		
	2013	2012	2011	**2013**	2012	2011
(Gains) losses reclassified from OCL to revenues	**$ (2.8)**	$ (22.4)	$ 7.1	**$ (3.9)**	$ (29.6)	$ 9.4
Gains recognized in OCL	**$ 1.7**	$ 9.2	$ 12.3	**$ 2.4**	$ 12.2	$ 16.5
Total	**$ (1.1)**	$ (13.2)	$ 19.4	**$ (1.5)**	$ (17.4)	$ 25.9

The Company expects the $0.1 million after-tax accumulated gain ($0.1 million pre-tax) reported in AOCL related to the natural gas cash flow hedges to be released to net income within the next twelve months.

26. Post-Employment Benefits

The defined pension benefit plan is a final salary plan which provides benefits to members in the form of a guaranteed level of pension payable for life or single life guaranteed ten years. The level of benefits provided is calculated as 2% of average eligible earnings, based on maximum annual eligible earnings of $86,111, in the best five years of the last ten years of participation in the plan. All benefit payments are from trustee-administered funds. Plan assets held in trust are governed by provincial regulations. Responsibility for governance of the plan rests with the Downstream pension committee who has also appointed experienced, independent professional experts such as investment managers, actuaries, custodians and trustees to assist with the management of the plans. The defined benefit health care plan is unfunded and Downstream meets the benefit payment obligation as it falls due.

Funding of the defined benefit pension plans complies with Canadian federal and provincial regulations, and requires contributions to the plans to be made based on independent actuarial valuation. These funding requirements are based on a separate actuarial valuation for funding purposes for which the assumptions may differ from the assumptions used to determine the net benefit asset or obligation that is recorded on the statement of financial position.

The measurement of the accrued benefit obligation and annual expense for the defined benefit plans requires actuarial calculations and the following key assumptions.

	December 31, 2013		December 31, 2012		January 1, 2012	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Discount rate	**4.8%**	**4.8%**	4.0%	4.0%	5.0%	5.0%
Expected long-term rate of return on plan assets – bonds/fixed income securities	**5.0%**	−	5.0%	−	5.0%	−
Expected long-term rate of return on plan assets – equity securities	**8.0%**	−	8.0%	−	8.0%	−
Rate of compensation increase	**3.5%**	−	3.5%	−	3.5%	−
Employee contribution of pensionable income	**6.0%**	−	6.0%	−	6.0%	−
Annual rate of increase in covered health care benefits	−	**8.0%**	−	8.0%	−	8.0%

The discount rates are determined with reference to market yields on high quality corporate bonds with similar duration to the benefit obligations at the end of the reporting period.

The expected long-term rate of return is based on the portfolio as a whole and not necessarily on the sum of the returns on individual asset categories and is calculated using the projected rates of return of the plan investment portfolio, including the expected forecast for inflation, risk premiums for each class of asset, and current and future financial market conditions.

The sensitivity of the defined benefit obligation to changes in assumptions is concentrated to the discount rate. Other changes in assumptions have minimal impact on the obligation as a result of salary and benefit restrictions under both the pension plans and other benefit plans. The effect of an increase/decrease of one percentage point in the discount rate will decrease/increase the benefit obligation for our pension plans by $13.5 million and will decrease/increase the benefit obligation for our other benefit plan by $1.1 million. The effect of a increase/decrease of one percentage point in the discount rate will decrease/increase net service cost of our pension plans by $1.1 million and decrease/increase the service cost of our other benefit plan by $0.1 million. The sensitivity of the discount rate assumes that all other assumptions remain constant.

Although, the sensitivity analysis noted above is based on changing one assumption while holding all other assumptions constant, this is unlikely to occur in reality since changes to some assumptions may be correlated. When calculating the sensitivity of the discount rate and the impact on the benefit obligation, the same method has been applied as for calculating the net benefit asset and net benefit obligation recognized in the statement of financial position.

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

Asset Category	Percentage of Plan Assets December 31, 2013	December 31, 2012	January 1, 2012
Equity securities			
- Consumer markets and healthcare	**19%**	19%	23%
- Energy and industrial	**19%**	18%	18%
- Financial Institutions	**17%**	17%	11%
- Information technology	**9%**	9%	9%
- Other	**6%**	6%	8%
Bonds/fixed income securities			
- Government and corporate bonds	**22%**	23%	19%
- Short-term investments	**6%**	8%	11%
- Other	**2%**	−	1%

The primary investment strategy is the security and long-term stability of plan assets, combined with moderate growth that corresponds to the participants' anticipated retirement dates. The investment policy is reviewed from time to time to ensure consistency with the plan objectives. The Company in conjunction with the plan asset investment managers manages the inherent risks of various asset classes by investing in a diversified portfolio. The plan assets are primarily invested in domestic and foreign equity funds and in domestic bonds. The target asset allocation for equity securities is approximately 70% (and within a range of 50% to 90%) and the target asset allocation for debt securities is approximately 30% (and within a range of 10% to 50%). From time to time, the actual asset allocations for equity securities and debt securities may vary slightly from the target allocation, while staying within the target range, as a result of market conditions, however, management reviews the investments on a regular basis to ensure they continue to meet the plans' investment strategy.

All of the plan assets have quoted prices in active markets. There are no shares of Harvest Operations Corp. included in the plan asset mix.

	December 31, 2013		December 31, 2012		January 1, 2012	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Employee benefit obligation, beginning of year	**$ (90.6)**	**$ (9.3)**	$ (70.8)	$ (8.2)	$ (63.8)	$ (7.9)
Current service costs	**(4.1)**	**(0.2)**	(2.6)	(0.3)	(2.5)	(0.3)
Interest	**(3.8)**	**(0.4)**	(3.7)	(0.4)	(3.5)	(0.4)
Contributions by plan participants	**(1.8)**	**(0.2)**	(1.8)	(0.2)	(1.6)	(0.2)
Actuarial gains/(losses) arising from financial assumptions	**10.4**	**1.1**	(14.4)	(0.7)	(1.5)	0.1
Benefits paid	**4.8**	**0.5**	2.7	0.5	2.1	0.5
Employee benefit obligation, end of year	**$ (85.1)**	**$ (8.5)**	$ (90.6)	$ (9.3)	$ (70.8)	$ (8.2)
Fair value of plan assets, beginning of year	**$ 67.5**	**$ −**	$ 53.0	$ −	$ 51.3	$ −
Expected return on plan assets	**2.8**	−	2.8	−	2.7	−
Employer contributions	**8.3**	**0.3**	9.8	0.3	3.3	0.3
Employee contributions	**1.8**	**0.2**	1.8	0.2	1.6	0.2
Actuarial gains/(losses) arising from financial assumptions	**11.2**	−	2.8	−	(3.8)	−
Benefits paid	**(4.8)**	**(0.5)**	(2.7)	(0.5)	(2.1)	(0.5)
Fair value of plan assets, end of year	**86.8**	−	67.5	−	53.0	−
Net asset (obligation) and carrying amount	**$ 1.7**	**$ (8.5)**	$ (23.1)	$ (9.3)	$ (17.8)	$ (8.2)

The table below shows the summary of the defined benefit net asset and obligation:

	December 31, 2013	December 31, 2012	January 1, 2012
Pension plans	**$ 1.7**	$ (23.1)	$ (17.8)
Other benefit plans	**(8.5)**	(9.3)	(8.2)
Net obligation	**$ (6.8)**	$ (32.4)	$ (26.0)

In accordance with the terms and conditions of the defined benefit plans, and in accordance with federal and provincial statutory requirements of the plans, the present value of refunds or reductions in future contributions is not lower than the balance of the total fair value of plan assets less the total present value of obligations and, as such, no decrease in the defined benefit asset was necessary at December 31, 2013.

The actual return on plan assets for the year ended December 31, 2013 was $13.9 million (2012 – a return of $5.6 million; 2011 – a loss of $1.1 million).

Total cash payments for employee future benefits, consisting of cash contributed by Downstream to the pension and other benefit plans were $8.6 million for the year ended December 31, 2013 (2012 – $10.1 million; 2011 - $3.6 million). Expected contributions to the pension and other benefit plans for 2014 are $4.3 million.

Actuarial valuations are completed annually for the defined benefit plans and post-retirement benefit plan.

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

	Year Ended December 31					
	2013		2012		2011	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Current service cost	**$ 4.1**	**$ 0.2**	$ 2.6	$ 0.3	$ 2.5	$ 0.3
Net interest expense	**1.0**	**0.4**	0.9	0.4	0.8	0.4
Net benefit plan expense	**$ 5.1**	**$ 0.6**	$ 3.5	$ 0.7	$ 3.3	$ 0.7

For the year ended December 31, 2013 the net benefit plan expense of $5.7 million (2012 – $4.2 million; 2011 – $4.0 million) has been included in operating expenses in the statement of comprehensive loss and actuarial gains of $18.1 million, after tax expense of $4.6 million (2012 – actuarial losses of $9.9 million, after tax recovery of $2.4 million; 2011 – actuarial losses of $4.2 million, after tax recovery of $1.0 million) have been included in other comprehensive loss. The cumulative amount of actuarial gains included in accumulated other comprehensive loss as at December 31, 2013 was $1.4 million, after tax expense of $0.4 million (2012 – cumulative actuarial losses of $16.7 million, after tax recovery of $4.2 million).

The weighted average duration of the defined benefit pension plan and other benefit plan is 14.3 years and 12.2 years respectively.

Downstream is exposed to a number of risks through the defined benefit plans, the most significant of which are detailed below:

(i) *Investment risk*

The plan liabilities are calculated using a discount rate set with reference to corporate bond yields; a plan deficit will result if the plan assets underperform this yield. The plan asset mix is weighted towards equities which are expected to outperform corporate bonds in the long-term while contributing volatility and risk in the short-term.

Due to the long-term nature of the plan liabilities, maintaining a higher proportion of equity investments is an appropriate element of the long-term strategy of the defined benefit plans and as managed by the pension committee.

(ii) *Interest risk*

A decrease in corporate bond yields will increase plan liabilities although this will be partially offset by an increase in the return on the plan's debt investments.

(iii) Longevity risk

The present value of the defined benefit plan obligation is calculated by reference to the best estimate of the mortality of plan participants both during and after their employment. An increase in the life expectancy of the plan participants will increase the plan's obligation.

In the case of funded plans, Downstream's pension committee ensures that the investment positions are managed so that long-term investments are in line with the obligations under the benefit plans. The objective is to match assets to the pension obligations by investing in long-term fixed interest securities with maturities that match the benefit payments as they fall due. The pension committee monitors the plan asset performance and ensures that investments are well diversified such that the failure of any single investment would not have a material impact on the overall level of assets.

Required payments under the defined benefit plans for the next five years are disclosed in note 29 "Commitments" and include special payments for solvency and funding deficiencies.

27. Inventories

	December 31, 2013	December 31, 2012	January 1, 2012
Petroleum products			
Upstream – pipeline fill	**$ 3.0**	$ 0.9	$ 1.4
Downstream	**43.8**	75.5	56.3
Total petroleum product inventory	**46.8**	76.4	57.7
Parts and supplies	**4.8**	4.4	3.3
	$ 51.6	$ 80.8	$ 61.0

For the year ended December 31, 2013, Downstream recognized inventory impairments of $6.6 million (2012 - $14.8 million; 2011 - $9.7 million). Downstream inventory impairment reversals during 2013 was $3.9 million (2012 - $8.4 million; 2011 - $7.2 million) due to improvement in market prices. Such write-down and recovery amounts are included as costs in "purchased products for processing and resale" in the consolidated statements of comprehensive loss. The amount of petroleum products inventory recognized as an expense during year is included in "purchased products for processing and resale expense" in the consolidated statements of comprehensive loss.

28. Related Party Transactions

a) ***Related party loans***

On December 30, 2013, Harvest entered into a subordinated loan agreement with KNOC to borrow up to $200 million at a fixed interest rate of 5.3% per annum. The full principal and accrued interest is payable on December 30, 2018. As of December 31, 2013, Harvest has drawn $80 million from the $200 million available under the loan agreement (December 31, 2012 and January 1, 2012 - $nil). The loan amount was recorded at fair value on initial recognition by discounting the future cash payments at the prevailing market interest rate of 7% for loans with similar terms. The difference between the fair value and the loan amount of $4.3 million was recognized in contributed surplus. For the year ended December 31, 2013, interest expense of $nil was recorded (2012 and 2011 - $nil). On February 28, 2014, Harvest borrowed an additional $80.0 million under the KNOC subordinated loan agreement.

On August 16, 2012, Harvest entered into a subordinated loan agreement with ANKOR to borrow US$170 million at a fixed interest rate of 4.62% per annum. The principal balance and accrued interest is payable on October 2, 2017. At December 31, 2013, Harvest's related party loan from ANKOR included $180.8 million (December 31, 2012 - $169.1 million; January 1, 2012 - $nil) of principal and $3.0 million (December 31, 2012 - $3.0 million; January 1, 2012 - $nil) of accrued interest. Interest expense was $8.1 million for the year ended December 31, 2013 (2012 - $3.0 million; 2011 - $nil).

The related party loans are unsecured and the loan agreements contain no restrictive covenants. For purposes of Harvest's credit facility covenant requirements, the related party loans are excluded from the 'total debt' amount but included in the 'total capitalization' amount. ***b) Directors and Key Management Personnel Remuneration***

Key management personnel include the Company's officers, other members of the executive management team and directors. The amounts disclosed in the table below are the amounts recognized as an expense during the reporting period related to key management personnel.

	Year Ended December 31		
	2013	2012	2011
Short-term employee benefits	**$ 5.1**	$ 5.3	$ 4.6
Other long-term benefits	**0.7**	0.4	1.0
Other	**–**	0.5	–
	$ 5.8	$ 6.2	$ 5.6

c) ***Other Related Party Transactions***

	Transactions			Balance Outstanding			
	Year Ended December 31			Accounts Receivable As At December 31		Accounts Payable As At December 31	
	2013	2012	2011	**2013**	2012	**2013**	2012
Revenues							
KNOC[(1)(2)]	**$ 4.1**	$ 0.1	$ –	**$ –**	$ –	**$ –**	$ –
Other KNOC subsidiaries [(2)]	**0.8**	0.8	–	**–**	0.1	**–**	–
Operating Expenses							
Other KNOC subsidiaries [(3)]	**$ 0.5**	$ 0.4	$ –	**$ –**	$ –	**$ –**	$ 0.3
G&A Expenses							
KNOC[(4)]	**$ (3.5)**	$ (5.6)	$ (1.0)	**$ –**	$ 1.6	**$ 0.5**	$ –
Finance costs							
KNOC[(5)]	**$ 2.8**	$ –	$ –	**$ –**	$ –	**$ 0.5**	$ –

(1) Global Technology and Research Centre ("GTRC) is used as a training and research facility for KNOC. In 2013, the amount is related to a geological study performed by GTRC on behalf of KNOC.

(2) KNOC Trading Corporation ("KNOC Trading") is a wholly owned subsidiary of North Atlantic. KNOC Trading bills KNOC, ANKOR and Dana Petroleum plc ("Dana") for oil marketing services, such as the sale of products, performed on behalf of KNOC, ANKOR and Dana. Both ANKOR and Dana are wholly owned subsidiaries of KNOC.

(3) Billing from ANKOR for office rent and salaries and benefits related to KNOC Trading.

(4) Reimbursement from KNOC for general and administrative expenses incurred by GTRC. Also included is Harvest's reimbursement to KNOC for secondee salaries paid by KNOC on behalf of Harvest.

(5) Charges from KNOC for the irrevocable and unconditional guarantee they provided on Harvest's 21/8% senior notes and the Senior Unsecured Credit Facility. A guarantee fee of 52 basis points per annum is charged by KNOC.

On February 28, 2014 KNOC purchased 100% of the shares of KNOC Trading Corporation for US$0.4 million.

29. Commitments

The following is a summary of Harvest's contractual obligations and estimated commitments as at December 31, 2013:

	Payments Due by Period				
	1 year	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Debt repayments[(1)]	$ 12.3	$ –	$ 2,243.3	$ –	$ 2,255.6
Debt interest payments[(1) (2)]	76.8	153.3	121.6	–	351.7
Purchase commitments[(3)]	75.5	20.0	70.0	–	165.5
Operating leases	11.8	8.6	6.2	2.8	29.4
Firm processing commitments	9.0	32.2	27.0	97.7	165.9
Firm transportation agreements	9.6	38.8	49.9	92.2	190.5
Feedstock and other purchase commitments[(4)]	927.8	–	–	–	927.8
Employee benefits[(5)]	2.6	5.2	1.2	3.8	12.8
Decommissioning and environmental liabilities[(6)]	35.6	60.7	42.9	1,485.7	1,624.9
Total	$ 1,161.0	$ 318.8	$ 2,562.1	$ 1,682.2	$ 5,724.1

(1) Assumes constant foreign exchange rate.

(2) Assumes interest rates as at December 31, 2013 will be applicable to future interest payments.

(3) Relates to drilling commitments, BlackGold oil sands project commitment and Downstream capital commitments.

(4) Includes commitments to purchase refinery crude stock and refined products for resale under the SOA with Macquarie. The amount will be net settled against any product sales to Macquarie.

(5) Relates to the expected contributions to employee benefit plans and long-term incentive plan payments.

(6) Represents the undiscounted obligation by period.

30. Supplemental Guarantor Condensed Financial Information

Harvest Breeze Trust No. 1, Harvest Breeze Trust No. 2, Breeze Resources Partnership, Hay River Partnership, 1496965 Alberta Ltd. and North Atlantic Refining Limited (collectively "guarantor subsidiaries") fully and unconditionally guarantees the 67/8% senior notes issued by Harvest Operations Corporation ("HOC"). Each of the guarantor subsidiaries is 100% owned by HOC. The full and unconditional guarantees may be automatically released under the following customary circumstances:

- the subsidiary is sold to a non-affiliate and ceases to be a restricted subsidiary;
- the subsidiary is designated as an "unrestricted" subsidiary for covenant purposes;
- the subsidiary's guarantee of the indebtedness (such as indebtedness under the credit facility agreement) which resulted in the creation of the notes guarantee is terminated or (other than by payment) released; or
- • upon legal defeasance or covenant defeasance or satisfaction and discharge of the indenture.

The following financial information for HOC, the guarantor subsidiaries and all other subsidiaries on a condensed consolidating basis is intended to provide investors with meaningful and comparable financial information about HOC and its subsidiaries and is provided pursuant to Rule 3-10 of Regulation S-X in lieu of the separate financial statements of each guarantor subsidiary. Investments include the investments in subsidiaries recorded under the equity method for the purposes of the condensed consolidating financial information. Equity income of subsidiaries is the group's share of profit related to such investments. The eliminations and reclassifications column includes the necessary amounts to eliminate the intercompany balances and transactions between subsidiaries. HOC's cost basis has not been pushed down to the subsidiaries as push-down accounting is not permitted in the separate financial statements of the subsidiaries.

CONDENSED STATEMENT OF FINANCIAL POSITION–
As at December 31, 2013

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Assets					
Current assets					
Cash and cash equivalents	$ –	$ –	$ –	$ –	$ –
Accounts receivable	95.2	71.6	2.1	–	168.9
Inventories	3.0	47.0	1.6	–	51.6
Prepaid expenses	12.8	1.3	–	–	14.1
Risk management contracts	0.3	–	–	–	0.3
Due from affiliates	1,016.1	83.0	0.3	(1,099.4)	–
	$ 1,127.4	$ 202.9	$ 4.0	$ (1,099.4)	$ 234.9
Non-current assets					
Long-term deposit	$ 5.0	$ –	$ –	$ –	$ 5.0
Investment tax credits and other	–	0.6	–	–	0.6
Deferred income tax asset	88.9	59.7	0.2	–	148.8
Exploration & evaluation assets	52.0	7.4	–	–	59.4
Property, plant and equipment	3,715.5	744.4	1.5	–	4,461.4
Investment in subsidiaries	(316.4)	(2.8)	–	319.2	–
Goodwill	379.8	–	–	–	379.8
Total assets	$ 5,052.2	$ 1,012.2	$ 5.7	$ (780.2)	$ 5,289.9
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	$ 202.3	$ 52.1	$ 3.9	$ –	$ 258.3
Current portion of long-term debt	–	12.3	–	–	12.3
Current portion of long-term provisions	39.1	–	–	–	39.1
Risk management contracts	0.6	–	–	–	0.6
Due to affiliates	75.7	1,014.5	9.2	(1,099.4)	–
	$ 317.7	$ 1,078.9	$ 13.1	$ (1,099.4)	$ 310.3
Non-current liabilities					
Long-term debt	1,965.2	9.9	(2.1)	–	1,973.0
Related party loan	259.6	–	–	–	259.6
Long-term liability	69.5	–	–	–	69.5
Long-term provisions	501.0	230.5	–	–	731.5
Post-employment benefit obligations	–	6.8	–	–	6.8
Intercompany loan	–	1,189.8	0.8	(1,190.6)	–
Total liabilities	$ 3,113.0	$ 2,515.9	$ 11.8	$ (2,290.0)	$ 3,350.7
Shareholder's equity	1,939.2	(1,503.7)	(6.1)	1,509.8	1,939.2
Total liabilities and shareholder's equity	$ 5,052.2	$ 1,012.2	$ 5.7	$ (780.2)	$ 5,289.9

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the year ended December 31, 2013

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Petroleum, natural gas, and refined product sales	$ 852.3	$ 4,630.0	$ 101.9	$ (65.6)	$ 5,518.6
Royalty expense	(112.9)	(41.0)	–	–	(153.9)
Earnings from equity accounted subsidiaries	(611.6)	(2.8)	–	614.4	–
Revenues	127.8	4,586.2	101.9	548.8	5,364.7
Expenses					
Purchased products for processing and resale	–	4,297.0	93.3	(62.9)	4,327.4
Operating	279.9	291.0	10.5	(2.7)	578.7
Transportation and marketing	22.5	5.5	–	–	28.0
General and administrative	54.7	14.0	–	–	68.7
Depletion, depreciation and amortization	425.3	187.5	–	–	612.8
Exploration and evaluation	11.0	1.3	–	–	12.3
Gain on disposition of property, plant & equipment	(34.0)	(0.1)	–	–	(34.1)
Finance costs	87.3	6.9	–	–	94.2
Risk management contracts gains	(4.4)	–	–	–	(4.4)
Foreign exchange (gains) losses	78.7	(34.5)	–	–	44.2
Impairment on property, plant and equipment	13.6	469.4	–	–	483.0
Loss before income tax	(806.8)	(651.8)	(1.9)	614.4	(846.1)
Income tax recovery	(24.8)	(39.4)	–	–	(64.2)
Net loss	$ (782.0)	$ (612.4)	$ (1.9)	$ 614.4	$ (781.9)
Other comprehensive income (loss)					
Losses on designated cash flow hedges, net of tax	(1.1)	–	–	–	(1.1)
Gains on foreign currency translation	–	7.9	–	–	7.9
Actuarial gains, net of tax	–	18.1	–	–	18.1
Share of equity accounted subsidiaries other comprehensive income, net of tax	26.0	–	–	(26.0)	–
Comprehensive loss	$ (757.1)	$ (586.4)	$ (1.9)	$ 588.4	$ (757.0)

CONDENSED STATEMENT OF CASH FLOWS
For the year ended December 31, 2013

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Cash provided by (used in) operating activities	$ (1.1)	$ 204.0	$ (2.3)	$ –	$ 200.6
Cash provided by (used in) financing activities	371.9	(103.3)	(2.1)	101.3	367.8
Cash used in investing activities	(371.5)	(103.2)	–	(101.3)	(576.0)
Change in cash and cash equivalents	(0.7)	(2.5)	(4.4)	–	(7.6)
Effect of exchange rate changes on cash	–	–	–	–	–
Cash and cash equivalents, beginning of year	0.7	2.5	4.4	–	7.6
Cash and cash equivalents, end of year	$ –	$ –	$ –	$ –	$ –

CONDENSED STATEMENT OF FINANCIAL POSITION–
As at December 31, 2012
(*Restated*)*

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Assets					
Current assets					
Cash and cash equivalents	$ 0.7	$ 2.5	$ 4.4	$ –	$ 7.6
Accounts receivable	102.4	69.2	4.0	–	175.6
Inventories	0.9	78.4	1.5	–	80.8
Prepaid expenses	13.5	6.7	–	–	20.2
Risk management contracts	1.8	–	–	–	1.8
Assets held for sale	16.9	–	–	–	16.9
Due from affiliates	748.5	66.0	0.4	(814.9)	–
	$ 884.7	$ 222.8	$ 10.3	$ (814.9)	$ 302.9
Non-current assets					
Long-term deposit	$ 5.0	$ –	$ –	$ –	$ 5.0
Investment tax credits and other	–	28.5	–	–	28.5
Deferred income tax asset	63.6	(2.8)	0.3		61.1
Exploration & evaluation assets	67.3	6.1	–	–	73.4
Property, plant and equipment	3,538.7	1,251.6	1.6	–	4,791.9
Investment in subsidiaries	370.4	–	–	(370.4)	–
Goodwill	391.8	–	–	–	391.8
Total assets	$ 5,321.5	$ 1,506.2	$ 12.2	$ (1,185.3)	$ 5,654.6
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	$ 225.5	$ 141.4	$ 6.1	$ –	$ 373.0
Current portion of long-term debt	331.8	–	–	–	331.8
Current portion of long-term provisions	28.1	–	–	–	28.1
Liabilities associated with assets held for sale	11.9	–	–	–	11.9
Due to affiliates	58.3	747.2	9.4	(814.9)	–
	$ 655.6	$ 888.6	$ 15.5	$ (814.9)	$ 744.8
Non-current liabilities					
Long-term debt	1,277.9	–	–	–	1,277.9
Related party loan	172.1	–	–	–	172.1
Long-term liability	8.2	–	–	–	8.2
Long-term provisions	515.8	211.5	–	–	727.3
Post-employment benefit obligations	–	32.4	–	–	32.4
Intercompany loan	–	1,189.8	0.8	(1,190.6)	–
Total liabilities	$ 2,629.6	$ 2,322.3	$ 16.3	$ (2,005.5)	$ 2,962.7
Shareholder's equity	2,691.9	(816.1)	(4.1)	820.2	2,691.9
Total liabilities and shareholder's equity	$ 5,321.5	$ 1,506.2	$ 12.2	$ (1,185.3)	$ 5,654.6

*See Note 3

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the year ended December 31, 2012
(*Restated*)*

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Petroleum, natural gas, and refined product sales	$ 902.2	$ 5,011.9	$ 92.2	$ (60.7)	$ 5,945.6
Royalty expense	(114.7)	(49.9)	–	–	(164.6)
Earnings from equity accounted subsidiaries	(557.9)	(0.1)	–	558.0	–
Revenues	229.6	4,961.9	92.2	497.3	5,781.0
Expenses					
Purchased products for processing and resale	–	4,494.4	85.1	(59.2)	4,520.3
Operating	288.6	328.5	6.0	(1.5)	621.6
Transportation and marketing	21.8	4.8	–	–	26.6
General and administrative	50.1	15.5	–	–	65.6
Depletion, depreciation and amortization	462.1	226.3	–	–	688.4
Exploration and evaluation	24.7	0.2	–	–	24.9
Gain on disposition of property, plant & equipment	(6.8)	(23.5)	–	–	(30.3)
Finance costs	107.2	3.8	–	–	111.0
Risk management contracts gains	(0.5)	–	–	–	(0.5)
Foreign exchange (gains) losses	(10.7)	9.4	–	–	(1.3)
Impairment on property, plant and equipment	11.3	546.0	–	–	557.3
Income (loss) before income tax	(718.2)	(643.5)	1.1	558.0	(802.6)
Income tax expense (recovery)	2.9	(85.0)	0.5	–	(81.6)
Net income (loss)	$ (721.1)	$ (558.5)	$ 0.6	$ 558.0	$ (721.0)
Other comprehensive income (loss)					
Losses on designated cash flow hedges, net of tax	(13.2)	–	–	–	(13.2)
Losses on foreign currency translation	–	(17.7)	–	–	(17.7)
Actuarial loss, net of tax	–	(9.9)	–	–	(9.9)
Share of equity accounted subsidiaries other comprehensive loss, net of tax	(27.6)	–	–	27.6	–
Comprehensive income (loss)	$ (761.9)	$ (586.1)	$ 0.6	$ 585.6	$ (761.8)

*See Note 3

CONDENSED STATEMENT OF CASH FLOWS
For the year ended December 31, 2012

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Cash provided by operating activities	$ 122.8	$ 318.7	$ 1.3	$ –	$ 442.8
Cash provided by (used in) financing activities	196.0	(171.5)	–	171.5	196.0
Cash used in investing activities	(318.6)	(147.7)	–	(171.5)	(637.8)
Change in cash and cash equivalents	0.2	(0.5)	1.3	–	1.0
Effect of exchange rate changes on cash	–	–	–	–	–
Cash and cash equivalents, beginning of year	0.5	3.0	3.1	–	6.6
Cash and cash equivalents, end of year	$ 0.7	$ 2.5	$ 4.4	$ –	$ 7.6

CONDENSED STATEMENT OF FINANCIAL POSITION–
As at December 31, 2011
(*Restated*)*

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Assets					
Current assets					
Cash and cash equivalents	$ 0.5	$ 3.0	$ 3.1	$ –	$ 6.6
Accounts receivable	121.3	89.8	1.2	–	212.3
Inventories	1.4	58.6	1.0	–	61.0
Prepaid expenses	11.8	6.7	–	–	18.5
Risk management contracts	20.2	–	–	–	20.2
Due from affiliates	517.1	44.8	0.2	(562.1)	–
	$ 672.3	$ 202.9	$ 5.5	$ (562.1)	$ 318.6
Non-current assets					
Long-term deposit	$ 24.9	$ –	$ –	$ –	$ 24.9
Investment tax credits and other	–	54.0	–	–	54.0
Exploration & evaluation assets	69.6	4.9	–	–	74.5
Property, plant and equipment	3,468.0	1,938.1	1.4	–	5,407.5
Investment in subsidiaries	1,127.4	0.1	–	(1,127.5)	–
Goodwill	404.9	–	–	–	404.9
Total assets	$ 5,767.1	$ 2,200.0	$ 6.9	$ (1,689.6)	$ 6,284.4
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	$ 259.0	$ 200.9	$ 2.3	$ –	$ 462.2
Current portion of long-term debt	107.1	–	–	–	107.1
Current portion of long-term provisions	17.1	–	–	–	17.1
Due to affiliates	39.3	513.3	9.5	(562.1)	–
	$ 422.5	$ 714.2	$ 11.8	$ (562.1)	$ 586.4
Non-current liabilities					
Long-term debt	1,486.2	–	–	–	1,486.2
Long-term liability	2.7	–	–	–	2.7
Long-term provisions	464.1	210.4	–	–	674.5
Post-employment benefit obligations	–	26.0	–	–	26.0
Deferred income tax liability	(62.2)	118.0	(0.9)	–	54.9
Intercompany loan	–	1,189.8	–	(1,189.8)	–
Total liabilities	$ 2,313.3	$ 2,258.4	$ 10.9	$ (1,751.9)	$ 2,830.7
Shareholder's equity	3,453.8	(58.4)	(4.0)	62.3	3,453.7
Total liabilities and shareholder's equity	$ 5,767.1	$ 2,200.0	$ 6.9	$ (1,689.6)	$ 6,284.4

*See Note 3

CONDENSED STATEMENTS OF COMPREHENSIVE LOSS
For the year ended December 31, 2011
(*Restated*)*

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Petroleum, natural gas, and refined product sales	$ 985.9	$ 3,579.5	$ 70.7	$ (46.9)	$ 4,589.2
Royalty expense	(146.3)	(49.2)	–	–	(195.5)
Earnings from equity accounted subsidiaries	(56.3)	(0.2)	–	56.5	–
Revenues	783.3	3,530.1	70.7	9.6	4,393.7
Expenses					
Purchased products for processing and resale	–	3,098.5	65.4	(45.8)	3,118.1
Operating	280.7	291.0	6.4	(1.1)	577.0
Transportation and marketing	22.2	13.7	–	–	35.9
General and administrative	48.2	14.4	–	–	62.6
Depletion, depreciation and amortization	423.9	202.8	–	–	626.7
Exploration and evaluation	16.0	2.3	–	–	18.3
Gain on disposition of property, plant & equipment	(7.9)	–	–	–	(7.9)
Finance costs	102.5	6.6	–	–	109.1
Risk management contracts gains	(6.7)	–	–	–	(6.7)
Foreign exchange (gains) losses	11.7	(15.8)	0.1	–	(4.0)
Loss before income tax	(107.3)	(83.4)	(1.2)	56.5	(135.4)
Income tax recovery	(1.8)	(27.6)	(0.6)	–	(30.0)
Net loss	$ (105.5)	$ (55.8)	$ (0.6)	$ 56.5	$ (105.4)
Other comprehensive income (loss)					
Gains on designated cash flow hedges, net of tax	19.4	–	–	–	19.4
Gains on foreign currency translation	–	21.5	–	–	21.5
Actuarial loss, net of tax	–	(4.2)	–	–	(4.2)
Share of equity accounted subsidiaries other comprehensive income loss, net of tax	17.3	–	–	(17.3)	–
Comprehensive loss	$ (68.8)	$ (38.5)	$ (0.6)	$ 39.2	$ (68.7)

*See Note 3

CONDENSED STATEMENT OF CASH FLOWS
For the year ended December 31, 2011

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Cash provided by (used in) operating activities	$ 62.1	$ 498.7	$ (0.3)	$ –	$ 560.5
Cash provided by (used in) financing activities	848.7	(157.1)	–	157.1	848.7
Cash used in investing activities	(922.8)	(341.7)	–	(157.1)	(1,421.6)
Change in cash and cash equivalents	(12.0)	(0.1)	(0.3)	–	(12.4)
Effect of exchange rate changes on cash	–	0.1	–	–	0.1
Cash and cash equivalents, beginning of year	12.5	3.0	3.4	–	18.9
Cash and cash equivalents, end of year	$ 0.5	$ 3.0	$ 3.1	$ –	$ 6.6

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (Unaudited

The information below provides supplemental information on the oil and gas producing activities of the Corporation as of December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011 in accordance Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 932, Extractive Activities - Oil and Gas. Activities not directly associated with oil and gas producing activities are excluded from all aspects of this supplemental information.

Tables I through III present information on Harvest's estimated net proved reserve quantities; standardized measure of discounted future net cash flows, and changes in the standardized measure of discounted future net cash flows. Tables IV through VI provide historical cost information pertaining to result of operations related to oil and gas producing activities, capitalized costs related to oil and gas producing activities, and costs incurred in oil and gas exploration and development. Financial information included in tables IV through VI is derived from Harvest's audited annual financial statements which are prepared in accordance with IFRS.

Table I: Net Proved Reserves (Harvest's Share After Royalties)

Harvest's net proved oil and gas reserves as of December 31, 2013 and 2012, and changes thereto for the years ended December 31, 2013, 2012 and 2011 are shown in the following table. Note that all Harvest's proved reserves are located within Canada. Proved reserves as of December 31, 2013 and 2012 were calculated using the average first-day-of-the-month oil and gas prices for the prior twelve-month period.

Proved oil and gas reserves, as defined within the SEC's Regulation S-X, are those quantities of oil and gas, which by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered:

1. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well; and
2. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

The process of estimating proved and proved developed reserves is very complex and requires significant judgment in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may change significantly over time as a result of numerous factors, such as but not limited to, additional development activities, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Although reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, reserve estimates are subject to change as additional information becomes available, and as future economic and operating conditions change.

	Crude Oil (MMbbls)	NGLs (MMbbls)	Bitumen (MMbbls)	Natural Gas (Bcf)	Total (MMBOE)
January 1, 2011	92.6	4.8	86.7	163.7	211.4
Revisions of previous estimates (including infill drilling & improved recovery)	2.7	2.5	(4.5)	21.1	4.2
Purchase of reserves in place	1.3	3.8	-	107.3	23.0
Sale of reserves in place	-	-	-	-	-
Discoveries and extensions	4.6	0.7	-	24.9	9.5
Production	(10.6)	(1.6)	-	(36.6)	(18.3)
December 31, 2011	90.6	10.2	82.2	280.4	229.8
Revisions of previous estimates (including infill drilling & improved recovery)	(0.9)	1.1	2.7	(42.7)	(4.3)
Purchase of reserves in place	-	-	-	-	-
Sale of reserves in place	(2.2)	(0.1)	-	(1.6)	(2.6)
Discoveries and extensions	2.7	-	-	14.1	5.0
Production	(11.1)	(1.7)	-	(37.5)	(19.1)
December 31, 2012	**79.1**	**9.5**	**84.9**	**212.7**	**208.8**
Revisions of previous estimates (including infill drilling & improved recovery)	(3.8)	-	3.2	45.6	6.9
Purchase of reserves in place	0.4	-	-	0.9	0.6
Sale of reserves in place	(4.3)	(0.3)	-	(13.2)	(6.8)
Discoveries and extensions	5.4	0.5	-	10.3	7.6
Production	(8.7)	(0.9)	-	(29.7)	(14.6)
December 31, 2013	**68.1**	**8.8**	**88.1**	**226.6**	**202.5**
Proved Developed					
December 31, 2011	79.7	8.6	-	226.6	126.0
December 31, 2012	71.0	7.3	-	168.9	106.3
December 31, 2013	**60.8**	**6.5**	**-**	**174.2**	**96.2**
Proved Undeveloped					
December 31, 2011	10.9	1.6	82.2	53.8	103.8
December 31, 2012	8.1	2.2	84.9	43.8	102.5
December 31, 2013	**7.3**	**2.3**	**88.1**	**52.4**	**106.3**

Table II: Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table provides the standardized measure of discounted future cash flows relating to the proved reserves disclosed in Table I above. Future cash inflows are computed using Harvest's after royalty share of estimated annual future production from proved oil and gas reserves and the average first-day-of-the-month oil and gas prices for the prior twelve-month period as prescribed by the SEC. Future development, production and decommissioning costs to be incurred in producing and further developing the proved reserves are based on the costs at the balance sheet date and assuming continuation of existing economic conditions. Future income taxes are computed by applying year-end statutory tax rates to estimated future pre-tax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using 10% mid-period discount factors. This discounting requires a year-by-year estimate of when the future expenditure will be incurred and when the reserves will be produced.

The information provided in this table does not represent Harvest's estimate of the Corporation's expected future cash flows or the fair market value of the proved oil and gas reserves due to several factors including:

- Estimates of proved reserve quantities are subject to change as new information becomes available;
- Probable and possible reserves, which may become proved in the future, are excluded from the calculations;

- Future prices and costs rather than twelve-month average prices and costs at balance sheet date will apply;
- Economic conditions such as interest rates and income tax rates and operating conditions may differ from what is used in the preparation of the estimates; and
- Future development and asset decommissioning costs will differ from those estimated.

(millions of Canadian dollars)		**December 31, 2013**		December 31, 2012
Future cash inflows	**$**	**11,860.0**	$	13,235.9
Less future:				
Production costs		**(6,011.3)**		(6,709.0)
Development costs		**(1,441.2)**		(1,609.4)
Decommissioning costs		**(983.5)**		(1,020.0)
Income taxes		**(45.2)**		(78.8)
Future net cash flows		**3,378.8**		3,818.7
Less 10% annual discount		**(1,363.0)**		(1,733.0)
Standardized measure of discounted future net cash flows	**$**	**2,015.8**	$	2,085.7

Table III: Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

(millions of Canadian dollars)		**December 31, 2013**		December 31, 2012		December 31, 2011
Future discounted net cash flow, beginning of year	**$**	**2,085.7**	$	2,839.2	$	1,863.9
Sales & transfers of oil and gas produced, net of production costs		**(602.2)**		(669.8)		(711.3)
Net change in sales & transfer prices and production costs related to future production		**165.4**		(646.8)		616.8
Development costs incurred during the period		**725.7**		566.7		680.3
Change in future development costs		**(510.5)**		(524.0)		(658.4)
Change due to extensions and discoveries		**141.5**		89.5		176.7
Accretion of discount		**210.6**		306.7		234.0
Sales of reserves in place		**(120.8)**		(77.1)		-
Purchase of reserves in place		**16.0**		0.3		293.3
Net change in income taxes		**10.3**		207.9		(162.3)
Changes due to revisions in timing of future net cash flow and other changes		**(105.9)**		(6.9)		506.2
Future discounted net cash flow, end of year	**$**	**2,015.8**	$	2,085.7	$	2,839.2
Net change for the year	**$**	**(69.9)**	$	(753.5)	$	975.3

Table IV: Results of Operations

			Year Ended December 31			
(millions of Canadian dollars)		**2013**		2012		2011
Petroleum and natural gas revenues, net of royalties	**$**	**947.8**	$	1,028.9	$	1,091.4
Less:						
Production costs		**345.6**		359.0		350.5
Exploration expense		**12.3**		24.9		18.3
Depletion, depreciation, and amortization(1)		**527.7**		577.5		533.4
Accretion of decommissioning liability		**21.6**		20.0		23.1
Impairment on oil and gas properties		**24.1**		21.8		-
Other (transportation and marketing costs)		**22.6**		22.2		29.6
Income tax expense(2)		**13.3**		7.3		29.7
Results of operations (excluding corporate overhead and interest costs)	**$**	**(19.4)**	$	(3.8)	$	106.8

(1) Excludes depreciation on corporate assets.
(2) Income tax expense has been calculated in accordance with FAS 69 using the statutory tax rate and reflecting tax deductions and credits and allowances relating to the oil and gas producing activities that are reflected in the consolidated income tax expense for the period.

Table V: Capitalized Costs

(millions of Canadian dollars)		**December 31, 2013**		December 31, 2012
Proved oil and gas properties[1][2]	**$**	**6,383.4**	$	5,7761.3
Unproved oil and gas properties				
Unproven properties included in property, plant and equipment[3]		**12.8**		7.1
Exploration and evaluation assets[2]		**59.4**		73.8
Total unproved oil and gas properties		**72.2**		80.9
Total capital costs		**6,455.6**		5,842.2
Accumulated depreciation, depletion and amortization ("DD&A") [2] [4] and impairment on oil and gas properties		**(2,097.7)**		(1,579.9)
Net capitalized costs	**$**	**4,357.9**	$	4,262.3

(1) Proved oil and gas properties exclude $14.9 million of corporate assets as at December 31, 2013 (December 31, 2012 - $10.2 million).
(2) As at December 31, 2012, Harvest had assets held for sale in proved oil and gas properties of $23.0 million with accumulated DD&A of $9.2 million and exploration and evaluation assets of $0.4 million.
(3) Costs related to incomplete wells as at year end. As at December 31, 2013, Harvest was in the process of drilling a total of 7 gross wells (December 31, 2012 – 19 gross wells).
(4) Accumulated DD&A excludes accumulated depreciation on corporate assets of $8.4 million as at December 31, 2013 (December 31, 2012 - $6.1 million).

Table VI: Costs Incurred

		Year Ended December 31				
(millions of Canadian dollars)		**2013**		2012		2011
Property acquisitions[1]						
Proved property	**$**	**13.7**	$	1.3	$	495.5
Unproved property		**-**		-		18.6
Total property acquisition costs		**13.7**		1.3		514.1
Exploration costs		**16.7**		41.1		50.9
Development costs[2]		**790.7**		670.2		669.4
Total costs incurred[3]	**$**	**821.1**	$	712.6	$	1,234.4

(1) Property acquisition costs include business and property acquisitions and exclude proceeds received from dispositions of $173.9 million for the year ended December 31, 2013 (2012 - $88.5 million; 2011 - $8.7 million).
(2) Development costs include asset retirement costs capitalized during the year and non-cash capital additions related to the BlackGold Engineering Procurement and Construction contract.
(3) Total costs incurred exclude costs related to corporate assets of $4.7 million for the year ended December 31, 2013 (2012 - $1.5 million; 2011 - $2.2 million).

EXHIBIT 12.1

CERTIFICATIONS

I, Myunghuhn Yi, certify that:

1. I have reviewed this annual report on Form 20-F of Harvest Operations Corp.;

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 company as of, and for, the periods presented in this report;

4. The company'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 company 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 company, 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 company'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 company'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 company's internal control over financial reporting; and

5. The company's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the company's auditors and the audit committee of the company'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 company'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 company's internal control over financial reporting.

Date: April 30, 2014

/s/ Myunghuhn Yi
Myunghuhn Yi
President & Chief Executive Officer

EXHIBIT 12.2

CERTIFICATIONS

I, Chang–Koo Kang, certify that:

1. I have reviewed this annual report on Form 20-F of Harvest Operations Corp.;

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 company as of, and for, the periods presented in this report;

4. The company'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 company 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 company, 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 company'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 company'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 company's internal control over financial reporting; and

5. The company's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the company's auditors and the audit committee of the company'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 company'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 company's internal control over financial reporting.

Date: April 30, 2014

/s/ Chang–Koo Kang
Chang–Koo Kang
Chief Financial Officer

EXHIBIT 13.1

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

In connection with the annual report of Harvest Operations Corp. (“Harvest”) on Form 20-F for the year ended December 31, 2013 (the "Report") as filed with the Securities and Exchange Commission on the date hereof, I, Myunghuhn Yi, President & Chief Executive Officer of Harvest, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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 Harvest.

Date: April 30, 2014

/s/ Myunghuhn Yi
Myunghuhn Yi
President & Chief Executive Officer

EXHIBIT 13.2

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

In connection with the annual report of Harvest Operations Corp. (“Harvest”) on Form 20-F for the year ended December 31, 2013 (the "Report") as filed with the Securities and Exchange Commission on the date hereof, I, Chang–Koo Kang, Chief Financial Officer of Harvest, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

3. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

4. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Harvest.

Date: April 30, 2014

/s/ Chang–Koo Kang
Chang–Koo Kang
Chief Financial Officer

GLJ Petroleum Consultants

Principal Officers:
Keith M. Braaten, P. Eng.
President & CEO
Jodi L. Anhorn, P. Eng.
Executive Vice President & COO

Officers / Vice Presidents:
Terry L. Aarsby, P. Eng.
Caralyn P. Bennett, P. Eng.
Leonard L. Herchen, P. Eng.
Myron J. Hladyshevsky, P. Eng.
Todd J. Ikeda, P. Eng.
Bryan M. Joa, P. Eng.
Mark Jobin, P. Geol.
John E. Keith, P. Eng.
John H. Stilling, P. Eng.

LETTER OF CONSENT

Mr. Wallace Catsirelis
Harvest Operations Corp.
2100, 330 - 5th Avenue S.W.
Calgary, Alberta T2P 0L4

We hereby consent to the use of our name and the inclusion of our report dated February 12, 2014 evaluating the petroleum and natural gas reserves of Harvest Operations Corp. (the "Corporation") as of December 31, 2013, in the Annual Report on Form 20-F for the year ended December 31, 2013 (the "Annual Report"). We hereby further consent to the use of information derived from our report in the Annual Report.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

Myron Hladyshevsky

Myron Hladyshevsky, P. Eng.
Vice President

Dated: April 28, 2014
Calgary, Alberta
Canada

THIRD PARTY REPORT ON RESERVES

By GLJ Petroleum Consultants Ltd. - (Independent Qualified Reserves Evaluator)

This report is provided to satisfy the requirements contained in Item 1202(a)(8) of U.S. Securities and Exchange Commission Regulation S-K and to include disclosure required under Item 1202(a)(7) of Regulation S-K

Terms to which a meaning is ascribed in *Regulation S-K* and *Regulation S-X* have the same meaning in this report.

We have prepared an independent evaluation of the oil and gas reserves of Harvest Operations Corp. (the "Company") for the management and the board of directors of the Company. The primary purpose of our evaluation report was to provide estimates of reserves information in support of the Company's year-end reserves reporting requirements under US Securities Regulation S-K and for other internal business and financial needs of the Company.

We have evaluated certain reserves of the Company as at December 31, 2013. The completion date of our report is February 10, 2014.

The following table sets forth the geographic area covered by our report, net proved reserves and net probable reserves estimated using constant prices and costs, and the proportion of the total company that we have evaluated.

	Company Net Reserves					
Canada (Western Canada)	Crude Oil Mbbl	Natural Gas MMcf	Natural Gas Liquids Mbbl	Bitumen Mbbl	Oil Equivalent Mbbl	Proportion of Oil Equivalent Reserves
Proved Reserves						
Developed producing	58,445	163,365	6,028	-	91,700	
Developed non-producing	2,265	10,842	461	-	4,532	
Undeveloped	7,266	52,411	2,264	88,081	106,346	
Total Proved	67,974	226,618	8,753	88,081	202,578	100%
Probable Reserves						
Developed	18,434	58,096	2,363	-	30,480	
Undeveloped	12,174	56,091	4,836	134,847	161,206	
Total Probable	30,608	114,187	7,199	134,847	191,686	100%

Note: Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of gas per one barrel of oil equivalent.

As required under SEC Regulation S-K, reserves are those quantities of oil and gas that are estimated to be economically producible under existing economic conditions. As specified, in determining economic production, constant product reference prices have been based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the effective date of our report. The following table summarizes the average benchmark prices and the average realized prices.

Twelve Month Average Benchmark Prices

Bank of Canada Average Noon Exchange Rate ($US/$C)	0.9714
NYMEX WTI ($US/bbl)	96.67
Light, Sweet Crude Oil at Edmonton ($C/bbl)	93.12
Bow River Crude Oil at Hardisty ($C/bbl)	77.27
Henry Hub NYMEX ($US/MMbtu)	3.67
AECO/NIT Spot ($C/MMbtu)	3.15
Edmonton Propane ($C/bbl)	36.78
Edmonton Butane ($C/bbl)	68.34

Average Realized Prices

Light/Medium Oil ($/bbl)	83.38
Heavy Oil ($/bbl)	72.86
Natural Gas ($/Mcf)	3.10
Natural Gas Liquids ($/bbl)	61.22
Bitumen ($/bbl)	45.55

In our economic analysis, operating and capital costs are those costs estimated as applicable at the effective date of our report, with no future escalation. Where deemed appropriate, the capital costs and revised operating costs associated with the implementation of committed projects designed to modify specific field operations in the future may be included in economic projections.

Our report has been prepared assuming the continuation existing regulatory and fiscal conditions subject to the guidance in the COGE Handbook and SEC regulations. Notwithstanding that the Company currently has regulatory approval to produce the reserves identified in our report, there is no assurance that changes in regulation will not occur; such changes, which cannot reliably be predicted, could impact the Company's ability to recovery the estimated reserves.

Oil and gas reserves estimates have an inherent degree of associated uncertainty the degree of which is affected by many factors. Reserves estimates will vary due to the limited and imprecise nature of data upon which the estimates of reserves are predicated. Moreover, the methods and data used in estimating reserves are often necessarily indirect or analogical in character rather than direct or deductive. Furthermore, the persons involved in the preparation of reserves estimates and associated information are required, in applying geosciences, petroleum engineering and evaluation principles, to make numerous unbiased judgments based upon their educational background, professional training, and professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render reserves estimates inherently imprecise. Reserves estimates may change substantially as additional data becomes available and as economic conditions impacting oil and gas prices and costs change. Reserves estimates will also change over time due to other factors such as knowledge and technology, fiscal and economic conditions, contractual, statutory and regulatory provisions.

To estimate the economically recoverable crude oil, natural gas and natural gas products reserves and related future net cash flows, we consider many factors and make assumptions including:

- 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 products prices adjusted for quality and transportation differentials based on historical data;

- future operating costs based on historical data;
- assumed effects of regulation by governmental agencies; and
- future development capital costs.

Our estimates are prepared using standard geological and engineering methods generally accepted by the petroleum industry, and the reserves definitions and standards required by the United States SEC. The methods we used for estimating reserves were volumetric calculations, material balance techniques, production and pressure decline curve analysis, analogy with similar reservoirs, and reservoir simulation. The method or combination of methods used is based on our professional judgment and experience. Estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The assumptions, data, method, and procedures that GLJ has used for the preparation of our report are appropriate for the purposes served by the report.

In our opinion, the reserves information evaluated by us have, in all material respects, been determined in accordance with all appropriate industry standards, methods and procedures applicable for the filing of reserves information under U.S. SEC Regulation S-K.

A summary of the Company reserves evaluated by us is provided in the table on the first page of this report.

Myron J. Hladyshevsky, P. Eng. was the technical person primarily responsible for overseeing the preparation of Harvest's reserves estimates. His certification of qualification has been attached as an Appendix to this report.

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada
April 28, 2014

Myron J. Hladyshevsky, P. Eng.
Vice President

CERTIFICATION OF QUALIFICATION

I, Myron J. Hladyshevsky, Professional Engineer, 4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of GLJ Petroleum Consultants Ltd., which company did prepare a detailed analysis of Canadian oil and gas properties of Harvest Operations Corp. (the “Company”). The effective date of this evaluation is December 31, 2013.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of the Company or its affiliated companies.

3. That I attended the University of Calgary and graduated with a Bachelor of Science Degree in Chemical Engineering in 1979; that I am a Registered Professional Engineer in the Province of Alberta; and, that I have in excess of thirty-four years experience in engineering evaluations of oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of the Company, and the appropriate provincial regulatory authorities.

PROFESSIONAL ENGINEER ALBERTA
MYRON J. HLADYSHEVSKY

GLJ Petroleum Consultants

Building a better
working world

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Securities and Exchange Commission

100 F Street, N.E.

Washington, DC 20549

Re: Harvest Operations Corp.

We were previously auditors for Harvest Operations Corp. and, under the date of February 28, 2013, we reported on the consolidated financial position of Harvest Operations Corp. as at December 31, 2012 and 2011, the consolidated statements of comprehensive loss, changes in shareholders' equity and cash flows for the year ended December 31, 2012 and 2011. We have read the statements included under Item 16F of Harvest Operations Corp.'s Form 20-F dated April 30, 2014 and we agree with such statements related to Ernst & Young LLP.

Yours very truly,

Ernst & Young LLP

Calgary, Canada

April 30, 2014