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

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

For the fiscal year ended: DECEMBER 31, 2015

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)

1500, 700 – 2nd Street SW, Calgary, Alberta, Canada T2P 2W1
(Address of principal executive offices)

Mr. Piljong Sung, Interim President & CEO
1500, 700 – 2nd Street SW, Calgary, Alberta, Canada T2P 2W1
Piljong.Sung@harvestenergy.ca
403-268-6596
(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, 2015: 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 ☑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 ☑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.

☑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 ☑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

☑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 ☑No

Table of Contents

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.

"6⅞% Senior Notes" means the Corporation's US $500 million 6⅞% Senior Notes due October 1, 2017.

"2⅛% Senior Notes" means the Corporation's US $630 million 2⅛% 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.

"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 13 of the Corporation's audited consolidated financial statements for the year ended December 31, 2015 under Item 18 in this annual report.

"Deep Basin Partnership" or "DBP" means Harvest's upstream joint venture with KERR formed on April 23, 2014.

"Downstream" means the Corporation's petroleum refining and marketing segment, which was sold on November 13, 2014. Downstream operated under the North Atlantic trade name and was 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 card lock 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.

"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.

"HK MS Partnership" or "HKMS" means Harvest's midstream joint venture with KERR formed on April 23, 2014.

"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, 2015, 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.

"KERR" means KERR Canada Co. Ltd., a corporation incorporated under the laws of Alberta.

"KNOC" means Korea National Oil Corporation.

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

"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. North Atlantic was sold by Harvest on November 13, 2014.

"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 6⅞% Senior Notes.

"Operating Subsidiaries" means Breeze Resource Partnership, Breeze Trust No. 1, Breeze Trust No. 2, and Hay River Partnership, each a 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:

(a) 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;

(b) 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; and

(c) the US$171 million loan agreement with KNOC, dated April 2, 2015 ("2015 KNOC loan") due December 31, 2017 at a fixed rate of 5.91% 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 including its share of production in equity investment in DBP as at December 31, 2015, 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.

"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.

"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
^{o}API	The measure of the density or gravity of liquid petroleum products
bcf	Billion cubic 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	Dated Brent, a benchmark for North Sea Brent blend crude oil
CO2e	Carbon dioxide equivalent
CPF	Central processing facility
DBP	Deep Basin Partnership
EBITDA	Earnings before interest, taxes, depreciation, and amortization
EOR	Enhanced oil recovery
GHG	Greenhouse gas
GJ	Gigajoule
HKMS	HK MS Partnership
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.)
tCO2e	Tonnes of CO2e
WCS	Western Canada Select
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, royalty rates, operating costs, commodity prices and results from its price risk management 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 and the sources of funding;
- 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;
- timing and the ability to achieve the maximum capacity from the BlackGold central processing facilities;
- 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 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;
- 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 costs and timing of commissioning 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 Harvest’s reserves;
- the ability to obtain equipment and arrange work force 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; and
- the ability to add production and reserves through development and exploitation activities.

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:

- adverse changes in the economy generally, such as global demand and supply for commodities;
- volatilities of commodity prices, especially the price differential between light oil and heavy oil;
- uncertainties in the estimation of reserves;
- costs associated with developing and producing Upstream and BlackGold reserves;
- uncertainties around Harvest's ability to obtain financing;
- 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 products to commercial markets;
- difficulties encountered during the drilling for and production of crude oil, natural gas, bitumen and other related products;
- difficulties encountered in the integration of acquisitions;
- uncertainties around realizing the value of acquisitions;
- 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;
- 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. "Revenues and other income" comprises of sales of petroleum and natural gas, net of related royalties, and Harvest's share of the net income (loss) from its joint ventures.

NON-GAAP MEASURES

Throughout this annual report, the Corporation has referred to certain measures of financial performance that are not specifically defined under IFRS such as "operating netbacks", "operating netbacks prior to/after hedging", "gross margin (loss)", "refining margin", "average refining gross margin", "cash contribution (deficiency) from operations", "Annualized EBITDA", "senior debt to annualized EBITDA", "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 derivative contracts. "Gross margin (loss)", "refining margin" or "average refining gross margin" 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. "Cash contribution (deficiency) from operations" is calculated as operating income (loss) adjusted for non-cash items. The measure demonstrates the ability of the each segment of Harvest to generate the cash from operations necessary to repay debt, make capital investments, and fund the settlement of decommissioning and environmental remediation liabilities. "Total financial liabilities, non-current" 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", "senior debt to total capitalization" and "total debt to total capitalization" are terms defined in Harvest's Credit Facility agreement for the purpose of calculation of financial covenants. The 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 the 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 (herein after referred to as "Annualized EBITDA") used in the Credit Facility agreement, prior to the amendments on April 22, 2015, 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. As the Credit Facility was amended in 2015, Annualized EBITDA was longer required at December 31, 2015. The following is a reconciliation of Annualized EBITDA to the nearest GAAP measure, net loss for 2014 and 2013:

	December 31, 2014	December 31, 2013
Net loss	**(440.2)**	(781.9)
DD&A	**448.0**	612.8
Finance costs	**96.8**	94.2
Income tax recovery	**(232.8)**	(64.2)
EBITDA	**(128.2)**	(139.1)
Unrealized losses on risk management contracts	**0.7**	0.5
Unrealized losses (gains) on foreign exchange	**103.3**	40.8
Unsuccessful exploration and evaluation costs	**9.4**	11.5
Impairment of PP&E	**446.9**	483.0
Losses (Gains) on disposition of assets	**8.9**	(34.1)
Loss from joint ventures	**4.7**	-
Other non-cash items	**8.7**	(1.7)
Adjustments on acquisitions and dispositions [(1)]	**4.6**	(15.4)
Annualized EBITDA	**459.0**	345.5

(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. The year ended December 31, 2014 includes the sale of the Downstream segment on November 13, 2014.

Cash Contribution (Deficiency) from Operations

Cash contribution (deficiency) from operations represents operating income (loss) adjusted for non-cash expense items within: operating, general and administrative, exploration and evaluation, depletion, depreciation and amortization, gains on disposition of assets, risk management contracts gains or losses, impairment and other charges, 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 the Upstream and Downstream segments of Harvest to generate cash from their operations and is calculated before changes in non-cash working capital. Effective November 13, 2014, the Downstream segment was sold. There are no operating activities to report for the BlackGold segment as it is under development, all amounts reported are pre-operating. The most directly comparable additional GAAP measure is operating income (loss). Operating income (loss) as presented in the notes to Harvest's consolidated financial statements is reconciled to cash contribution (deficiency) from operations below, which is then reconciled to cash flow from operating activities:

	Year Ended December 31											
	Upstream			BlackGold			Downstream[1]			Total		
($ millions)	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Operating loss	**(1,167.9)**	(188.8)	(16.6)	**(508.7)**	—	—	**—**	(226.1)	(691.1)	**(1,676.6)**	(414.9)	(707.7)
Adjustments:												
Loss from joint ventures	**97.3**	4.7	—	**—**	—	—	**—**	—	—	**97.3**	4.7	—
Operating, non-cash	**(0.9)**	2.3	0.9	**—**	—	—	**—**	(2.0)	(2.8)	**(0.9)**	0.3	(1.9)
General and administrative, non-cash	**12.4**	1.8	1.7	**—**	—	—	**—**	—	—	**12.4**	1.8	1.7
Exploration and evaluation, non-cash	**27.5**	9.4	11.5	**—**	—	—	**—**	—	—	**27.5**	9.4	11.5
Depletion, depreciation and amortization	**418.1**	435.2	530.0	**0.5**	—	—	**—**	12.8	82.8	**418.6**	448.0	612.8
Gains on disposition of assets	**1.7**	(47.5)	(33.9)	**—**	—	—	**—**	(0.2)	(0.2)	**1.7**	(47.7)	(34.1)
Unrealized losses on risk management	**0.8**	0.7	0.5	**—**	—	—	**—**	—	**—**	**0.8**	0.7	0.5
Impairment and other charges, non-cash	**765.3**	267.6	24.1	**491.0**	—	—	**—**	179.3	458.9	**1,256.3**	446.9	483.0
Cash contribution (deficiency) from operations	**154.3**	485.4	518.2	**(17.2)**	—	—	**—**	(36.2)	(152.4)	**137.1**	449.2	365.8
Inclusion of items not attributable to												
Net cash interest										**(81.7)**	(63.0)	(72.9)
Realized foreign exchange gains (losses)										**(2.1)**	(1.5)	(3.4)
Realized foreign exchange gain on senior unsecured credit facility										**—**	—	1.3
Cash income taxes										**(6.9)**	—	—
Settlement of decommissioning and environmental										**(15.6)**	(14.0)	(19.6)
Change in non-cash working capital										**(66.2)**	112.2	(70.6)
Cash flow from operating activities										**(35.4)**	482.9	200.6

(1) Downstream results are from January 1 – November 13, 2014. The Downstream segment was sold on November 13, 2014 and results have been classified as "Discontinued 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 is derived from the audited consolidated financial statements, which have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). On November 13, 2014, Harvest closed the sale of its wholly-owned subsidiary North Atlantic. In accordance with IFRS 5 – Non-current Assets Held for Sale and Discontinued Operations, results of North Atlantic have been presented as discontinued operations. Prior years' income statement data have been reclassified to show the discontinued operations separately from continuing operations.

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".

(millions of Canadian dollars, except for per share amounts)	**2015**	**2014**	**2013**	**2012**	**2011**
Income statement data					
Net revenues from continuing operations	364.3	891.6	947.8	1,028.9	1,091.4
Loss from continuing operations before income tax	(2,125.2)	(410.5)	(187.5)	(114.2)	(9.3)
Net income (loss) from continuing operations	(1,793.4)	(85.6)	(148.1)	(91.1)	1.0
Net loss from continuing operations per common share					
Basic and diluted	(4.65)	(0.22)	(0.38)	(0.24)	—
Net loss from discontinued operations	(15.5)	(354.6)	(633.8)	(629.9)	(106.4)
Net loss	(1,808.9)	(440.2)	(781.9)	(721.0)	(105.4)
Net loss per common share					
Basic and diluted	(4.69)	(1.14)	(2.03)	(1.87)	(0.28)
Distributions/dividends declared	—	—	—	—	—
Distributions/dividends declared - U.S. dollars(1)	—	—	—	—	—
Distributions declared, per common share	—	—	—	—	—
Balance sheet data					
Total assets	3,928.1	5,091.6	5,289.9	5,654.6	6,284.4
Net assets (deficiency)	(275.3)	1,534.8	1,939.2	2,691.9	3,453.7
Shareholder's capital	3,860.8	3,860.8	3,860.8	3,860.8	3,860.8
Temporary equity	—	—	—	—	—
Share data					
Weighted average common shares outstanding					
Basic and diluted	386,078,649	386,078,649	386,078,649	386,078,649	377,908,587

(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 27, 2016 was US$0.7925.

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:

Period	High	Low
March 2016	0.7687	0.7387
February 2016	0.7374	0.7101
January 2016	0.7152	0.6821
December 2015	0.7464	0.7141
November 2015	0.7627	0.7468
October 2015	0.7728	0.7530

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:

Year	Average
2015	0.7767
2014	0.9025
2013	0.9666
2012	1.0004
2011	1.0110

B. Capitalization and Indebtedness

Not applicable.

C. Reasons for the Offer and Use of Proceeds

Not applicable.

D. Risk Factors

Harvest's Upstream and BlackGold 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 as at the reporting date.

RISKS ASSOCIATED WITH COMMODITY PRICES

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

Harvest's Upstream operations are dependent on the prices received for oil and natural gas production. Oil and natural gas prices are determined by supply and demand factors and are volatile. Similar to other western Canadian oil producers, Harvest has been negatively impacted by price declines in the level of crude oil prices. Absolute levels of global crude oil prices have been negatively impacted by declining global demand and growth expectations, increased global production capacity, the end of US quantitative easing and a strengthening US dollar. Continued strong US domestic crude oil production, primarily from the northern Bakken fields and from shale oil plays has exceeded demand from refineries and has put pressure on storage levels throughout the US, resulting in constrained WTI prices. Harvest continues to experience 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. The light oil and heavy oil price differential continues to be volatile, primarily due to supply and demand imbalances caused by 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 approximately 27% of Harvest's production is in heavy oil, continued widening of these differentials could have a significant negative impact on Harvest. North America natural gas reserves have significantly increased, primarily as a result of advances in hydraulic fracturing techniques. Natural gas prices are impacted by North

American inventory levels which have increased from the prior year due to productions growth and mild winter temperatures. As a result natural gas prices have significantly declined in the last year.

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 a material 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 expenses 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.

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 Harvest's exposure to the volatility in electrical power prices, it may enter into fixed priced forward purchase contracts for a portion of the Harvest's electrical power consumption in Alberta. In respect of the operations in British Columbia and Saskatchewan, 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 EH&S 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. Harvest employs prudent risk management practices and maintains property and liability insurance in amounts consistent with industry standards. In addition, business interruption insurance has been purchased for selected facilities. Harvest 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 Harvest 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 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 Harvest's control.

Harvest's ability to market its production depends upon numerous factors beyond its 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 to pipeline. 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 uncertainties regarding 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 over time as a result of natural declines. 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 it will remain the Operator of such properties or that it will operate other properties that it may acquire.

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns.

Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. In addition, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity or the demand for crude oil and natural gas.

Expiration of licences and leases

Certain of the Harvest's properties are held in the form of licences and leases and Working Interests in licences and leases. If Harvest or the holder of the licence or lease fails to meet the specific requirements of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of Harvest's licences or leases or the Working Interests relating to a licence or lease may have a material adverse effect on Harvest's results of operations and business.

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

Although title reviews will generally be conducted on Harvest's 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 an adverse effect on Harvest's financial condition and results of operations.

Aboriginal claims could have an adverse effect on Harvest's operations.

Aboriginal peoples have claimed aboriginal title and rights in portions of western Canada. Harvest is not aware that any claims have been made in respect of its properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on Harvest's business, financial condition, results of operations and prospects.

RISKS ASSOCIATED WITH RESERVES ESTIMATES

The reservoir and recovery information in reserves reports 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 Harvest's properties may differ. There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves, including many factors beyond Harvest's control. The reserves data, as disclosed in "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 therefrom, 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 Harvest's reserves may vary from such estimates, and such variances could be material.

Harvest's proved 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 Reserve 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 Independent Reserves Evaluator in related reserves reports. 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 INVESTMENT IN JOINT ARRANGEMENTS

Harvest's investment in joint arrangements is also subject to the same risks that are described above for commodity prices, Upstream operations and reserve estimates.

In the event that DBP redeems the partnership units of KERR, Harvest may be liable for this obligation if DBP does not have sufficient funds for the redemption.

In addition, as KERR has the ability to cause DBP to redeem all its preferred partnership units for consideration equal to its initial contribution plus a specified minimum after-tax internal rate of return, there is a risk that Harvest would have to meet this obligation if DBP does not have sufficient funds to complete the redemption obligation. This obligation could also arise upon the termination of this arrangement. See note 12, "Investment in Joint Ventures" in the audited Consolidated Financial Statements for the year ended December 31, 2015, under Item 18.

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 project is subject to execution risks that are inherent in similar projects, such as failure to properly design and engineer the project 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;
- the impact from changing government regulations and public scrutiny over oil sands development; and
- severe weather conditions.

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 increases target production to 30,000 bbl/d was approved by provincial regulators in 2013.

The recent commodity price collapse has led to Harvest deferring commissioning and start-up of Phase one. If the project is deferred for a long period of time, there could be negative material consequences, including: loss of reserves associated with the project; loss of cost pools available for royalty incentives; compromising of central processing facility equipment and well bores and continuance of impairment of the project.

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 labour 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 will 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 ACQUISITIONS AND DISPOSITIONS

Harvest may not be able to realize the anticipated benefits of acquisitions and dispositions

Harvest makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as Harvest's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of Harvest. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that Harvest can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets, if disposed of, could be expected to realize less than their carrying value on the financial statements.

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 may have an 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 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 6⅞% 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 Contracts" of this annual report. Harvest reviews the covenants regularly based on historical financial results. If Harvest 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 to 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.

Subsequent to the 2015 year end, Harvest's syndicate banks consented to a waiver of the Total Debt to Capitalization covenant for the duration of the Credit Facility and the maturity date remains at April 30, 2017. Please see Item 4 "Recent Developments" and "Material Contracts" in this annual report for more details.

Harvest 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;
- an uncompetitive position relative to Harvest's competitors whose debt and financial commitment levels are lower; and
- insolvency and bankruptcy.

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. Harvest currently has $1,554.6 million of long-term fixed interest rate debt outstanding that require repayments in 2017 through to 2018. Harvest also currently has a $1 billion financial covenant based syndicated revolving credit facility that matures on April 30, 2017.

To the extent that new or existing sources of financing becomes limited, unavailable or available on unfavorable terms, Harvest'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 6⅞% Senior Notes, 2⅛% Senior Notes, its Related Party Loan with Ankor, its 2015 Related Party Loan with KNOC and any LIBOR based loans and the related interest charges are denominated in U.S. 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, Harvest 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.

Harvest 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 Harvest of commodity price increases or changes in interest rates and foreign exchange rates. Harvest may also suffer financial loss because of hedging arrangements if:

- Harvest is unable to produce crude oil or natural gas 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, 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. 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 Harvest to 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 and waste management. If Harvest 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, 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 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 may be subject to litigation and claims under such litigation may be material.

In the normal course of operations, Harvest may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and it is possible that there could be material adverse developments in pending or future proceedings and as a result, could have a material adverse effect on Harvest's assets, liabilities, business, financial condition and results of operations.

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 Harvest and its 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 Corporations 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 oil and 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 capacity and new customers or marketing channels 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 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 securities of the Corporation. In addition, the loss of key management could have an adverse effect on Harvest. 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 its 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 industry. If such counterparties do not fulfill their contractual obligations or settle their liabilities, Harvest 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.

Harvest may disclose confidential information relating to its business, operations or affairs while discussing potential business relationships or other transactions with third parties.

Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to the business. The harm to the business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, Harvest will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Harvest currently operates only in western Canada and expansion into new activities may increase Harvest's risk exposure.

The operations and expertise of Harvest's management are currently focused primarily on oil and gas production, exploration and development in the western Canada sedimentary basin. In the future, Harvest may acquire or move into new industry related activities or new geographical areas or may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase Harvest's exposure to one or more existing risk factors, which may in turn result in Harvest's future operational and financial conditions being adversely affected.

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, 2015, Harvest's net proved reserves (excluding its equity investment in the DBP) represented approximately 27% of KNOC's consolidated oil and gas reserves. Additionally, Harvest's oil and gas production (excluding its equity interest in the DBP) represented approximately 18% of KNOC's consolidated 2015 oil and gas production.

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

The head and principal office of Harvest is located at 1500, 700 – 2nd Street SW, Calgary, Alberta, Canada T2P 2W1 while the registered office of Harvest Operations is located at Suite 4500, Bankers Hall East 855 – 2nd Street S.W., Calgary, Alberta T2P 4K7.

RECENT DEVELOPMENTS

On February 27, 2015, Harvest closed the acquisition of Hunt Oil Company of Canada, Inc. ("Hunt") by acquiring all of the issued and outstanding common shares of Hunt for cash consideration of approximately $37.1 million ($34.9 million net). Hunt was a private oil and gas company with operations immediately offsetting Harvest's lands and gas and liquids rich production in the Deep Basin area of Alberta. Subsequently, on October 1, 2015, Harvest disposed of the assets acquired from Hunt in the amount of $57.4 million to the DBP in exchange for partnership units.

In early 2015, construction of the BlackGold CPF plant site, well pads, and connecting pipelines was substantially completed. As a result, Harvest discharged its contractor and performed commissioning activities at a measured pace throughout 2015. Harvest postponed first steam for the BlackGold project in response to the unfavourable heavy oil price environment and will continually assess the commodity price environment to determine when to complete commissioning the CPF and commence steam injection.

In March 2015, the gas processing facility constructed by Harvest's equity investment, HKMS, was completed, allowing for the processing of the DBP's production.

On April 2, 2015 Harvest entered into a US$171 million loan agreement with KNOC repayable within one year from the date of the first drawing, which was on April 10, 2015. At December 31, 2015, US$120 million was drawn on this loan and KNOC approved an extension in the maturity date to December 31, 2017.

On April 22, 2015, Harvest amended the terms of its existing credit facility and replaced it with a $940 million syndicated revolving credit facility maturing on April 30, 2017. On July 15, 2015, Harvest secured a $60 million commitment from a new lender to increase the borrowing capacity of the credit facility to $1 billion. The amended credit facility is guaranteed by KNOC. Under the amended facility, applicable interest and fees are based on a margin pricing grid based on the Moody's and S&P credit ratings of KNOC. The financial covenants under the existing credit facility were deleted and replaced with a new covenant: Total Debt to Capitalization ratio of 70% or less. As at December 31, 2015 Harvest was in violation of its Total Debt to Capitalization covenant, resulting in the classification of the credit facility as a current liability at December 31, 2015 on the consolidated statement of financial position.

On May 1, 2015 Harvest closed the disposition of certain non-core oil and gas assets in Eastern Alberta for the total of $28.4 million in net proceeds.

On February 5, 2016, Harvest's syndicate banks consented to a waiver of the Total Debt to Capitalization covenant that was breached as at December 31, 2015, effective until April 30, 2017.

As at April 28, 2016, Harvest was fully drawn on the US$171 million loan agreement with KNOC. See "General Description of Capital Structure" of this annual report for details.

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)	**2015**	2014	2013
Upstream capital expenditures	**146.5**	408.6	322.3
BlackGold capital expenditures	**84.4**	281.9	382.6
Downstream capital expenditures	**—**	27.8	53.2
Total capital expenditures	**230.9**	718.2	758.1
Acquisitions			
Business	**34.9**	—	—
Property	**0.6**	6.4	13.7
Divestitures			
Property	**(41.8)**	(243.8)	(174.2)
Business Segment	**—**	(37.9)	—
Net acquisition and divestiture activities	**(6.3)**	(275.3)	(160.5)
Investment in joint ventures	**93.0**	26.7	—
Net capital investment	**317.6**	469.6	597.6

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

On October 2015 Harvest disposed of certain gas assets to the Deep Basin Partnership in the amount of $57.5 million for partnership units. On May 1, 2015 Harvest closed the sale of certain non-core oil and gas assets in Eastern Alberta for approximately $28.4 million in net proceeds. On February 27, 2015 Harvest closed the acquisition of Hunt by acquiring all the issued and outstanding common shares for total consideration of approximately $37.1 million.

During 2014, Harvest's Upstream segment closed the disposition of certain non-core oil and gas assets in Alberta and Saskatchewan for total proceeds of approximately $243.0 million. Prior to the disposal of Downstream, the Downstream segment received proceeds of approximately $0.8 million from minor dispositions.

In addition, on April 23, 2014, Harvest entered into the DBP and HKMS joint ventures with KERR. Harvest contributed certain producing and non-producing properties to DBP and contributed cash of $26.7 million to HKMS in 2014.

On November 13, 2014, Harvest closed the sale of its Downstream subsidiary for proceeds of approximately $70.5 million subject to post-closing adjustments. Total net cash inflow for Harvest was $37.9 million after taking into consideration the ending cash balance in Downstream of $32.6 million.

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. In addition, Harvest's Downstream segment received proceeds of approximately $0.3 million from minor dispositions.

Please refer to Item 4D "Property, Plant and Equipment" for details regarding the Corporation's 2015 capital expenditure plan and Harvest's material properties.

B. Business Overview

Harvest is a significant operator in Canada's energy industry with two operating segments: Upstream and BlackGold. In addition, Harvest entered into two joint ventures with KERR: DBP and HKMS. The DBP was formed to explore, develop and produce from the Deep Basin area and HKMS was formed to construct and operate a gas processing facility, used primarily to process gas produced by DBP.

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. Harvest 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 detailed 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, 2015 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, three and five-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 spot contracts and evergreen contracts, both related to the prevailing monthly market price.

Natural Gas

All of Harvest's natural gas production is being sold at the prevailing daily spot market price in western Canada.

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

($ millions)	**2015**	2014	2013
Light / medium oil sales after hedging(1)(2)	**158.7**	336.6	363.7
Heavy oil sales(1) (2)	**188.6**	437.9	455.6
Natural gas sales(1) (3)	**106.3**	161.6	147.6
Natural gas liquids sales(2)	**42.4**	94.9	112.1
Other(4)	**14.3**	15.0	22.7
Petroleum and natural gas sales	**510.3**	1,046.0	1,101.7
Royalties	**(48.7)**	(149.7)	(153.9)
Revenues	**461.6**	896.3	947.8

(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 2015, no natural gas was delivered to a pipeline that ships to the United States (2014 – 10%; 2013 – 10%).
(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 and trends 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 minimizes 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 industry-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.

The majority of Harvest environmental expenditures relate to site remediation, site reclamation and reporting to regulatory bodies. In 2015, Harvest spent $6.9 million on the management and closure of environmental obligations which included all required regulatory monitoring and reporting, remediation of spill sites, remediation of sites with historical contamination, and the reclamation of abandoned well sites and access roads. In 2015, Harvest had 620 active reclamation sites at the end of the fourth quarter. Harvest applied for 27 reclamation certificates in 2015, a total of five were received, due to delays in reviewing applications by the Alberta Energy Regulator. In addition, Harvest completed 65 surface well abandonments which will add to the number sites requiring reclamation in the future. Efforts towards other aspects of environmental protection and controls, such as water usage, waste management, air monitoring and emission reporting are ongoing.

In 2014, 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 through a third party review. Completion of this process is expected by the end of 2016 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 2015 Harvest opted to use the "COR Action Plan Maintenance Process". This process allows HOC to develop and implement an action plan based on previous external audit findings and internal analysis of our Environment, Health & Safety Management System (EHS MS). The goal of the action plan is to improve the overall EHS MS and target key opportunities for improvement. The 2015 submission to the certifying partner (EnForm) received a passing score of 93%. Harvest will use the same process for maintenance requirements in 2016 (2016 Action Plan has been submitted to EnForm for approval). Once approved, the 2016 action plan will be presented to the Harvest Board of Directors and will be shared with all staff via quarterly newsletter or field safety meetings. The Corporate Emergency Response Plan completed the required annual review process 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's Incident Command System.

Harvest met all regulatory compliance obligations in 2015 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 incurred immaterial compliance costs associated with these various programs and regulations.

CONTROLS AND REGULATIONS

The oil and gas 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 oil and 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 oil and 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, natural gas at 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.

Pipeline Capacity

Although pipeline expansions are ongoing, the apportionment of capacity on pipeline systems can occur from time-to-time due to pipeline operational problems. This affects the ability to market crude oil and natural gas. Most of the current apportionments, however, are due to significant supply which far 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.

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 reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments.

Alberta

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "MRF"). The MRF will take effect on January 1, 2017. Wells drilled prior to January 1, 2017 will continue to be governed by the current "Alberta Royalty Framework" for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. While the metrics for calculating the Mid-Life phase royalty have yet to be released, the rate will be determined based on commodity prices and are intended, on average, to yield the same internal rate of return as under the current Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently estimated to be 20 bbl/d for oil and 200 mcf/d for gas, the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, are scheduled to be released by March 31, 2016.

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the method and figures by which the royalties are calculated will be released to the public at a later date. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1 and 9 percent depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma: rates are 1 percent when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9 percent when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1 to 9 percent and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25 percent and increase for every dollar of market price of oil increase above $55 up to 40 percent when oil is priced at $120 or higher.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties, for wells drilled prior to January 1, 2017, are paid pursuant to "The New Royalty Framework" (implemented by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008) and the "Alberta Royalty Framework" until January 1, 2027. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the Freehold Mineral Rights Tax Act (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is four percent of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "IETP") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques, and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "Emerging Resource and Technologies Initiative"). These initiatives apply to wells drilled before January 1, 2017, for a 10 year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5 percent for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5 percent for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5 percent for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5 percent with volume and production month limits set according to the depth (including the horizontal distance) of the well, retroactive to wells that commenced drilling on or after May 1, 2010.

While the MRF eliminates the various royalty credits and incentives outlined above for wells drilled after December 31, 2016, the Government of Alberta has committed to creating cost allowance programs for both enhanced oil recovery schemes and higher risk experimental drilling. Details of these programs were released simultaneously with the finalization of the MRF, on April 21, 2016. The MRF structure consists of three stages during the life cycle of a well; pre-payout, post payout, and post payout mature well. A company will pay a flat royalty of 5% on a well's early production until the well's total revenue, from all hydrocarbon products, equals payout. Afterwards, the company will pay higher royalty rates that vary depending on the resource and market prices. Royalty rates will drop to match declining production rates when the well reaches a Maturity Threshold.

Payout is determined by the drilling and completion cost allowance (DCCA), which is based on average industry drilling and completion costs for well costs. It determines the allowable revenue after which individual well sites begin paying higher royalty rates (post-payout). The calculation of DCCA is the same for all wells, regardless of what hydrocarbon the well produces. When a company drills a well, the well's true vertical depth (TVD), total lateral length (TLL) and total proppant placed (TPP) are entered into the Drilling and Completion Cost Allowance formula to calculate the DCCA value for the well. The formula for wells deeper than 2000 metres reflects the higher complexity and cost per metre to drill a deep well. The formulas for calculation the DCCA are the following;

For wells with TVD shallower than or equal to 2,000 metres

$$DCCA(\$) = 1{,}170*(TVD-249) + 800*TLL + 0.6*TVD*TPP$$

For wells with TVD deeper than 2,000 metres

$$DCCA(\$) = 1{,}170*(TVD-249) + 3{,}120*(TVD-2{,}000) + 800*TLL + 0.6*TVD*TPP$$

The royalty formulas are price sensitive and product specific. The actual royalty rate is the sum of a price component and a quantity adjustment component that applies when monthly production from the well is below the Maturity Threshold, equivalent of 40 barrels of oil equivalent per day. The royalty rate has a minimum of 5% and a maximum of 40%.

<u>Saskatchewan</u>

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”). On March 29, 2014, the AER assumed the energy related functions and responsibilities of ESRD in the areas of environment and water under the Environmental Protection and Enhancement Act and the Water Act, respectively.

BLACKGOLD

The BlackGold segment focuses on the exploration, development and ultimately the production of in-situ oil sands located near Conklin, Alberta. BlackGold uses SAGD technology that utilizes horizontal drilling and thermal stimulation to maximize energy efficiency and minimize land disturbance. Phase 1 of the project is anticipated to produce 10,000 bbl/day. The scope of Phase 1 includes the drilling of 77 SAGD injector-producer well pairs over the life of the project and the construction of a CPF. Phase 2 of the project is targeted to expand processing capacity and increase output to 30,000 bbl/d and was approved by the provincial regulators in 2013.

Initial drilling of 30 SAGD wells (15 well pairs) was completed by the end of 2012 and the majority of the well completion activities were completed by the end of 2014. 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.

Construction, including the building of the CPF plant site, well pads, and connecting pipelines was substantially completed in early 2015. Several systems have since been commissioned and others will be progressed at a measured pace based on liquidity and the economic environment. The decision to complete commissioning of the CPF and commence steam injection depends on a number of factors including the bitumen pricing environment. Under the current price environment and labour market, the best estimate to complete the remaining pre-commissioning and commissioning activities to reach first steam is 5-6 months and $40-$50 million. Following first steam, an additional $17 million of capitalized costs is expected to circulate the wells with steam prior to commencing SAGD operations. The method of financing these activities will be through asset sales, debt and cash flow. See Item 3D “Risk Factors” for detail discussion on risks specific to the BlackGold project.

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.

DEEP BASIN AND HK MS PARTNERSHIPS

On April 23, 2014, Harvest entered into the DBP and HKMS joint ventures with KERR. The principal place of operations for both DBP and HKMS is in Canada. DBP was established for the purposes of exploring, developing and producing from oil and gas properties in the Deep Basin area in northwest Alberta. On April 23, 2014, Harvest contributed certain producing and non-producing properties to DBP in exchange for 467,386,000 of common partnership units (82.32% ownership interest), while KERR contributed $100.4 million for 100,368,000 preferred partnership units (17.68% ownership interest). On August 29, 2014, KERR contributed an additional $32.9 million to the DBP for an additional 32,913,506 preferred partnership units increasing KERR’s ownership interest to 22.19% and diluting Harvest’s ownership interest to 77.81%. During 2015, Harvest contributed cash and certain non-financial assets to the Partnership in exchange for 128,195,234 common partnership units, increasing Harvest’s ownership interest to 81.71% and diluting KERR’s ownership interest to 18.29%.

Amounts contributed by KERR are being spent by the DBP to purchase land, drill and develop partnership properties in the Deep Basin area. As the initial funding from KERR is consumed and additional funds are required to fund the entire agreed initial multi-year development program, Harvest intends to fund the balance of the program and will obtain proportionately increased shares in each Partnership in exchange for Harvest’s incremental capital investment.

HKMS 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 DBP. A gas processing agreement was entered by the two partnerships. For the HK MS Partnership, KERR initially contributed $22.6 million on April 23, 2014 for 22,632,000 partnership units, which represented 34.82% of the outstanding partnership units. On August 29, 2014, KERR contributed an additional $7.4 million to HKMS for an additional 7,421,673 partnership units increasing KERR’s ownership interest to 46.24%. During 2015, Harvest contributed cash to the Partnership in exchange for 34,938,130 common partnership units, increasing Harvest’s ownership interest to 69.93% and diluting KERR’s ownership interest to 30.07%. Harvest accounts for HKMS using the equity method of accounting.

The construction of the gas processing facility was completed in early 2015. Strategically, this facility provides the DBP an advantage of access to firm processing capability, the ability to extract maximum liquids from the natural gas produced by DBP and will allow DBP to pursue both acquisition and drilling opportunities in the region.

Harvest accounts for DBP and HKMS using the equity method of accounting.

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, natural gas and NGLs proved reserves and 100% of probable reserves as of December 31, 2015.

Harvest's investment in Deep Basin Partnership is accounted for using the equity method of accounting. GLJ was also retained to evaluate 100% of DBP's natural gas and NGLs proved reserves and 100% of probable reserves as of December 31, 2015.

In certain tables that follow, information is first provided in respect of Harvest and its Operating Subsidiaries, which are consolidated for financial reporting purposes (under the heading "Consolidated Entities") and then in respect of DBP (under the heading "Equity Investment"). All information with respect to DBP reflects Harvest's 81.71% equity interest in DBP as at December 31, 2015 and 77.81% equity interest in DBP as at December 31, 2014.

Readers are cautioned that Harvest does not have any direct or indirect interest in, or right to, the reserves or production of DBP disclosed herein.

All reserves were evaluated using the cost assumptions as at December 31, 2015 and the average first-day-of-the-month prices for the year ended December 31, 2015. All 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"), Exploitation, 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, Operations and Development reports to the Deputy Chief Operating Officer and Vice President, BlackGold ("Deputy COO"), Taeheon Jang, 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, Operations and Development. 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 reserves evaluation expertise in each area 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, Operations and Development 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, Operations and Development 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, Operations and Development 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 of Harvest Consolidated Entities and its equity accounted investment using constant pricing in accordance with the SEC's guidelines as of December 31, 2015. 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									
Consolidated Entities	Light and Medium Oil (MMbbls)		Heavy Oil (MMbbls)		Natural Gas (Bcf)		Natural Gas Liquids (MMbbls)		Total Oil Equivalent (MMboe)	
Reserves Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved										
Developed Producing	20.2	18.8	7.2	7.0	122.6	113.9	4.1	3.0	52.0	47.7
Developed Non-Producing	1.8	1.6	0.5	0.4	4.7	4.4	0.2	0.1	3.3	2.9
Undeveloped	1.5	1.3	0.1	0.1	17.7	16.8	2.3	2.0	6.9	6.2
Total Proved	23.5	21.7	7.8	7.5	145.0	135.1	6.6	5.1	62.2	56.8
Probable										
Developed	8.3	7.7	2.5	2.4	41.1	37.9	1.2	0.8	19.0	17.4
Undeveloped	4.2	3.8	—	—	16.1	15.2	1.4	1.1	8.1	7.4
Total Probable	12.5	11.5	2.5	2.4	57.2	53.1	2.6	1.9	27.1	24.8
Equity Investment										
Reserves Category										
Proved										
Developed Producing	—	—	—	—	27.5	24.9	1.7	1.3	6.3	5.5
Developed Non-Producing	—	—	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	4.2	4.0	0.7	0.6	1.4	1.2
Total Proved	—	—	—	—	31.7	28.9	2.4	1.9	7.7	6.7
Probable										
Developed	—	—	—	—	9.8	8.7	0.6	0.4	2.3	1.9
Undeveloped	—	—	—	—	2.0	1.8	0.3	0.2	0.6	0.5
Total Probable	—	—	—	—	11.8	10.5	0.9	0.6	2.9	2.4
Total(1)										
Reserves Category										
Proved										
Developed Producing	20.2	18.8	7.2	7.0	150.1	138.8	5.8	4.3	58.3	53.2
Developed Non-Producing	1.8	1.6	0.5	0.4	4.7	4.4	0.2	0.1	3.3	2.9
Undeveloped	1.5	1.3	0.1	0.1	21.9	20.8	3.0	2.6	8.3	7.4
Total Proved	23.5	21.7	7.8	7.5	176.7	164.0	9.0	7.0	69.9	63.5
Probable										
Developed	8.3	7.7	2.5	2.4	50.9	46.6	1.8	1.2	21.3	19.3
Undeveloped	4.2	3.8	—	—	18.1	17.0	1.7	1.3	8.7	7.9
Total Probable	12.5	11.5	2.5	2.4	69.0	63.6	3.5	2.5	30.0	27.2

(1) Total Consolidated Entities plus Total Equity Investment

Undeveloped Reserves

As at December 31, 2015, Harvest has a total of 10.3 MMboe of reserves that are classified as proved non-producing, and of these non-producing reserves approximately 71% 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, 2015. Substantially all of the undeveloped reserves are based on Harvest's then current 2016 budget and long range development plans for the major assets noted elsewhere in this document. Please also refer to Item 3D "Risk Factors" for further discussion of risks related to the reserves.

	Undeveloped Reserves				
Consolidated Entities	Crude Oil (MMbbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbls)	Bitumen (MMbbls)	Total Proved Undeveloped Reserves (MMboe)
Opening Balance December 31, 2014	7.2	70.6	2.7	84.4	106.1
Revision of previous estimates *(includes infill drilling & improved recovery)*	(4.6)	(50.9)	(1.2)	(84.4)	(98.7)
Discoveries and extensions	—	4.3	0.5	—	1.2
Sales and purchases	—	(0.4)	—	—	0.0
Production	—	—	—	—	—
Moved from undeveloped to developed	(1.2)	(6.8)	(0.1)	—	(2.4)
Closing Balance December 31, 2015	**1.4**	**16.8**	**1.9**	—	**6.2**
Equity Investment					
Opening Balance December 31, 2014	—	13.0	1.3	—	3.5
Revision of previous estimates *(includes infill drilling & improved recovery)*	—	(9.0)	(0.8)	—	(2.3)
Discoveries and extensions	—	—	—	—	—
Sales and purchases	—	—	—	—	—
Production	—	—	—	—	—
Moved from undeveloped to developed	—	—	—	—	—
Closing Balance December 31, 2015	—	**4.0**	**0.5**	—	**1.2**
Total[(1)]					
Opening Balance December 31, 2014	7.2	83.6	4.0	84.4	109.6
Revision of previous estimates *(includes infill drilling & improved recovery)*	(4.6)	(59.9)	(2.0)	(84.4)	(101.0)
Discoveries and extensions	—	4.3	0.5	—	1.2
Sales and purchases	—	(0.4)	—	—	0.0
Production	—	—	—	—	—
Moved from undeveloped to developed	(1.2)	(6.8)	(0.1)	—	(2.4)
Closing Balance December 31, 2015	**1.4**	**20.8**	**2.4**	—	**7.4**

The greatest changes to the proved undeveloped reserves (PUD) category between prior and current year end come from discoveries and extensions, primarily relating to the Deep Basin area of Alberta which is primarily gas, the Deep Basin Partnership of Alberta which is primarily gas, the Hay area which is primarily oil and the Red Earth area of Alberta which is primarily oil. These prospects are developed using long horizontal wells with multi-stage fracturing.

The PUD conversions (moved from undeveloped to developed) are also mostly in these same four areas stated above since that is where we were actively drilling and converting our PUDs to Prove Developed. Other revisions are also a result of product price changes.

Revisions also primarily occurred in these same four areas as noted above. Subsequent year revisions such as these typically occur as a result of drilling activity over the year end (winter drilling) means production data is not well established before year end bookings take place and reserves then tend to get revised the following year when production history has been established.

Other revisions are also a result of product price changes, mostly related to the BlackGold bitumen property.

<u>Conventional</u>

All of Harvest's proved undeveloped reserves relate to the conventional oil and gas reserves. Of the conventional undeveloped reserves, approximately 19% 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 2015, Harvest drilled a gross total of 26 wells (19.2 net) with the vast majority of the development taking place in the following areas: Hay River, Deep Basin, Red Earth and Western Alberta. The bulk of the wells drilled had been previously assigned proved undeveloped (PUD) reserves and therefore these reserves were converted to prove developed. Total PUD reserves converted during 2015 were 2.4MMboe which translates to a conversion rate of approximately 39% of the conventional oil and gas PUD reserves that existed at the end of 2015. In 2015, the cost incurred to develop proved undeveloped reserves was $0.5 million.

New PUD reserves were also assigned during the 2015 year-end evaluation recognizing the ongoing development of Harvest's properties. Total PUD reserves added for the 2015 year-end evaluation were 1.2MMboe.

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.

Oil Sands

All of Harvest's Bitumen reserves proved to be uneconomic in the current pricing environment as it relates to reserve definitions.

Production Volumes

	Gross Production Volumes — Annual		
Consolidated Entities	**2015**	**2014**	**2013**
Natural Gas *(MMcf)*	38,785	35,136	40,629
Oil and Natural Gas Liquids *(Mbbls)*			
Light and Medium Oil	3,200	3,840	4,260
Heavy Oil	4,125	5,436	6,170
Natural Gas Liquids	1,444	1,594	1,951
Total Oil and Natural Gas Liquids	8,769	10,870	12,381
Total Production*(Mboe)*	15,233	16,726	19,153
Equity Investment(1)			
Natural Gas *(MMcf)*	5,620	1,323	—
Natural Gas Liquids *(Mbbls)*	275	77	—
Total Production*(Mboe)*	1,212	298	—

(2) Harvest entered into the equity investment on April 23, 2014, as such, year-to-date period for 2014 reflects production from April 23 to December 31, 2014.

	Production Volumes — Annual		
	2015	**2014**	**2013**
Consolidated Entities			
Natural Gas *(MMcf)*	35,649	32,971	38,253
Oil and Natural Gas Liquids *(Mbbls)*			
Light and Medium Oil	2,835	3,226	3,585
Heavy Oil	3,717	4,629	5,190
Natural Gas Liquids	1,248	1,368	1,692
Total Oil and Natural Gas Liquids	7,800	9,223	10,467
Total Production*(Mboe)*	13,742	14,718	16,842
Equity Investment(1)			
Natural Gas *(MMcf)*	5,340	1,090	—
Natural Gas Liquids *(Mbbls)*	262	63	—
Total Production*(Mboe)*	1,152	244	—

(3) Harvest entered into the equity investment on April 23, 2014, as such, year-to-date period for 2014 reflects production from April 23 to December 31, 2014.

	Gross Production Volumes — 2015				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Consolidated Entities					
Natural Gas *(mcf/d)*	106,259	98,055	117,419	103,639	105,887
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil	8,768	7,934	8,633	8,695	9,832
Heavy Oil	11,301	10,044	11,155	11,969	12,058
Natural Gas Liquids	3,956	3,820	3,998	3,779	4,231
Total Oil and Natural Gas Liquids	24,025	21,798	23,786	24,443	26,122
Total (*boe/d*)	41,735	38,141	43,356	41,716	43,770
Equity Investment					
Natural Gas *(mcf/d)*	15,397	21,266	16,928	17,488	5,719
Natural Gas Liquids *(bbls/d)*	752	883	881	969	969
Total (*boe/d*)	3,319	4,427	3,703	3,884	1,223

	Production Volumes — 2015				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Consolidated Entities					
Natural Gas *(mcf/d)*	97,667	83,439	110,161	96,735	100,383
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil	7,767	7,046	7,720	7,895	8,421
Heavy Oil	10,185	9,136	9,967	10,994	10,662
Natural Gas Liquids	3,420	2,976	3,562	3,276	3,875
Total Oil and Natural Gas Liquids	21,372	19,158	21,249	22,165	22,958
Total (*boe/d*)	37,650	33,064	39,609	38,288	39,688
Equity Investment					
Natural Gas *(mcf/d)*	14,630	20,457	17,459	15,553	4,848
Natural Gas Liquids *(bbls/d)*	717	843	944	863	910
Total (*boe/d*)	3,156	4,253	3,855	3,456	1,019

	Gross Production Volumes — 2014				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Consolidated Entities					
Natural Gas *(mcf/d)*	96,265	91,092	94,970	98,295	100,823
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil	10,520	10,132	10,395	10,573	10,989
Heavy Oil	14,893	13,116	14,469	16,245	15,777
Natural Gas Liquids	4,368	4,109	4,101	4,356	4,917
Total Oil and Natural Gas Liquids	29,781	27,357	28,965	31,174	31,683
Total (*boe/d*)	45,825	42,539	44,794	47,556	48,487
Equity Investment[1]					
Natural Gas *(mcf/d)*	5,250	4,603	5,623	5,619	n/a
Natural Gas Liquids *(bbls/d)*	307	176	415	337	n/a
Total (*boe/d*)	1,183	945	1,354	1,274	n/a

(4) Harvest entered into the equity investment on April 23, 2014, as such, production volumes shown for Q2 reflects the production period from April 23 to June 30, 2014 and the year-to-date period reflects production from April 23 to December 31, 2014.

	Production Volumes — 2014				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Consolidated Entities					
Natural Gas *(mcf/d)*	90,334	87,714	90,889	87,781	95,026
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil	8,840	8,808	8,793	8,534	9,228
Heavy Oil	12,682	11,497	12,223	13,275	13,764
Natural Gas Liquids	3,747	3,740	3,650	3,331	4,275
Total Oil and Natural Gas Liquids	25,269	24,045	24,666	25,140	27,267
Total (*boe/d*)	40,324	38,664	39,814	39,770	43,103
Equity Investment[1]					
Natural Gas *(mcf/d)*	4,325	3,823	4,241	5,118	n/a
Natural Gas Liquids *(bbls/d)*	248	151	319	284	n/a
Total (*boe/d*)	970	789	1,027	1,138	n/a

(5) Harvest entered into the equity investment on April 23, 2014, as such, production volumes shown for Q2 reflects the production period from April 23 to June 30, 2014 and the year-to-date period reflects production from April 23 to December 31, 2014.

	Gross Production Volumes — 2013				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Consolidated Entities					
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 — 2013				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Consolidated Entities					
Natural Gas *(mcf/d)*	104,802	99,546	108,121	102,796	108,808
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil	9,822	8,817	9,022	10,117	11,368
Heavy Oil	14,219	13,516	13,941	14,576	14,863
Natural Gas Liquids	4,635	3,978	4,805	4,504	5,264
Total Oil and Natural Gas Liquids	28,676	26,311	27,768	29,197	31,495
Total (*boe/d*)	46,143	42,903	45,788	46,330	49,629

Per-Unit Results of the Consolidated Entities

	Per-Unit Results — 2015				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas ($/boe)					
Average sales price(1)	15.74	13.82	16.81	15.22	16.86
Royalties	1.24	2.04	1.06	1.02	0.88
Operating expenses	13.27	13.91	13.43	14.10	11.71
Crude Oil — Light and Medium ($/bbl)					
Average sales price	49.59	45.52	48.78	58.68	45.56
Royalties	5.59	5.07	5.16	5.56	6.44
Operating expenses	22.62	20.25	21.51	23.40	24.86
Crude Oil — Heavy ($/bbl)					
Average sales price(1)	42.69	35.63	41.23	53.22	39.53
Royalties	4.15	3.25	4.29	4.32	4.56
Operating expenses	19.23	18.19	15.00	18.72	24.33
Crude Oil — Total ($/bbl)					
Average sales price(1)	45.71	40.00	44.52	55.52	42.24
Royalties	4.78	4.05	4.73	4.78	5.46
Operating expenses	20.71	19.10	17.84	20.69	24.73
Natural Gas Liquids ($/bbl)					
Average sales price	29.36	26.61	26.56	33.45	30.91
Royalties	3.95	8.35	2.99	4.36	2.63
Operating expenses	9.70	0.05	11.72	13.12	13.65
Total ($/boe)					
Average sales price(1)	32.33	27.89	31.47	37.85	31.85
Royalties	3.19	3.38	2.89	3.19	3.34
Operating expenses	16.50	14.96	15.28	17.29	18.40

(1) Before gains or losses on commodity derivatives.

	Per-Unit Results — 2014				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas ($/boe)					
Average sales price(1)	28.92	19.26	26.69	31.95	36.99
Royalties	2.28	1.37	1.59	3.96	2.13
Operating expenses	13.37	14.97	14.24	13.23	11.23
Crude Oil — Light and Medium ($/bbl)					
Average sales price	87.65	69.69	90.50	98.43	91.35
Royalties	14.59	12.05	15.60	17.61	14.64
Operating expenses	26.59	27.62	30.50	23.61	27.86
Crude Oil — Heavy ($/bbl)					
Average sales price(1)	78.59	62.33	81.71	87.45	80.25
Royalties	11.91	9.90	12.46	14.67	10.13
Operating expenses	23.68	22.08	21.89	22.98	27.14
Crude Oil — Total ($/bbl)					
Average sales price(1)	82.34	65.53	85.39	91.78	84.81
Royalties	13.13	11.04	13.61	15.46	12.09
Operating expenses	25.09	24.95	25.12	22.68	27.71
Natural Gas Liquids ($/bbl)					
Average sales price	59.53	46.96	59.81	61.06	68.67
Royalties	9.76	6.17	7.56	16.16	8.97
Operating expenses	13.42	16.87	13.60	12.54	11.16
Total ($/boe)					
Average sales price(1)	62.24	47.99	62.99	69.30	67.29
Royalties	8.95	6.98	8.55	11.77	8.30
Operating expenses	19.76	20.34	19.66	18.80	20.29

(1) Before gains or losses on commodity derivatives.

	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

(6) Before gains or losses on commodity derivatives.

Drilling Activity

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

	2015			
	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil Wells	—	—	13.0	13.0
Gas Wells	—	—	10.0	3.2
Service Wells	—	—	2.0	2.0
Stratigraphic Test Wells	—	—	—	—
Dry Holes	—	—	1.0	1.0
Total Wells	—	—	26.0	19.2

	2014			
	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil Wells	2.0	2.0	60.0	55.9
Gas Wells	—	—	25.0	11.6
Service Wells	—	—	6.0	6.0
Stratigraphic Test Wells	—	—	4.0	4.0
Dry Holes	1.0	0.7	2.0	2.0
Total Wells	3.0	2.7	97.0	79.5

	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

Present Activities

Conventional

At December 31, 2015, Harvest's Consolidated Entities was not of drilling or participating in development wells.

Oil Sands

The 15 SAGD well pairs which form the initial drilling development of Phase 1 (10,000 bpd) of BlackGold oil sands project were drilled by the end of 2012. As of the end of 2015 all well pairs had been completed and were ready for steaming. In 2015 the construction had been substantially completed, including the building of the CPF plant site, well pads, connecting pipelines and several systems have since been commissioned.

Harvest's plans for 2016 are to continue with minor pre-commissioning activities and then decide whether or not to proceed to commissioning and steam injection depending on the price outlook for bitumen.

Location of Wells

The following table summarizes the Consolidated Entities' interests in producing wells and wells capable of producing as at December 31, 2015.

	Oil		Gas		Total[(1)(2)]	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	3,274	2,489	2,186	802	5,460	3,291
British Columbia	592	496	153	59	745	555
Saskatchewan	762	676	40	36	802	712
Total	4,628	3,661	2,379	897	7,007	4,558

(1) Harvest has varying royalty interests in 740 natural gas wells and 323 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 787 gross natural gas wells and 877 gross crude oil wells.

Developed and Undeveloped Acreage

The following table summarizes the Consolidated Entities' developed, undeveloped and total landholdings as at December 31, 2015.

	Developed[(1)]		Undeveloped[(2)]		Total	
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	931	524	632	469	1,563	993
British Colombia	131	78	224	141	355	219
Saskatchewan	53	49	23	22	76	71
Total	1,115	651	879	633	1,994	1,283

(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.

The following table summarizes the Consolidated Entities' developed and undeveloped land holdings, expiring within one year from December 31, 2015.

	Developed[(1)]		Undeveloped[(2)]		Total	
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	—	—	104	104	104	104
British Colombia	—	—	18	12	18	12
Saskatchewan	—	—	8	8	8	8
Total	—	—	130	124	130	124

(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 a 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".

ENVIRONMENTAL REGULATION

The oil and gas industry is subject to environmental regulations issued pursuant to a variety of provincial and federal laws. 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

Canada committed to an Intended Nationally Determined Contribution of reducing GHG emissions by 30 percent below 2005 levels by 2030 as a part of the Paris Agreement at the United Nations Framework Convention on Climate Change Conference held in Paris, France in December 2015. The Agreement includes non-binding pledges from 195 countries to hold the increase in global average temperatures to well below 2 degree Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius. The countries which agreed to the Paris Agreement committed to meeting every five years to review their individual progress on GHG emissions reductions and to consider amendments to non-binding individual country targets. Canada is required to report and monitor its GHG emissions, though the implementation of such reporting and monitoring has yet to be determined. The Paris Agreement also contemplates that by 2020 the parties thereto will develop a new market-based mechanism related to carbon trading, which is expected to be based largely on lessons learned from the Kyoto Protocol. The government of Canada has announced that it will develop a country-wide approach to implementing the Paris Agreement in 2016.

Harvest is unable to predict the impact of the Paris Agreement on its operations. It is possible that mandatory emissions reduction requirements may have a material adverse effect on the Company's financial condition, results of operations and cash flow.

Alberta

In 2015, Alberta announced a major shift in its climate regulations. Facilities that emit over 100,000 tonnes of CO2e per year will be required to reduce their emissions intensity by 15 percent over baseline conditions by January 1, 2016 (previously this was 12 percent) which will increase to 20 percent by January 1, 2017. The price of the carbon levy (which may be used to make up for any shortfall in actual emissions intensity reductions) will also increase from $15/tCO2e to $20/tCO2e for 2016 and $30/tCO2e for 2017. As of January 1, 2018, these facilities will fall under a newly proposed product-based performance standard, the details of which have not yet been developed. As of January 1, 2017 Alberta will be implementing a broad-based carbon price designed to cover emissions across all sectors, starting at $20 per tonne and moving to $30 per tonne on January 1, 2018. The price will increase in real terms each year after that. Conventional oil and gas facilities emitting less than 100,000 tCO2e per year will be levied starting on January 1, 2023, to allow time for these facilities to reduce methane emissions under the newly proposed Joint Initiative on Methane Reduction and Verification. Consultations with industry and other stakeholders are ongoing to develop these regulations. Finally, total emissions from the oil sands will be capped at a maximum of 100 mega tonnes in any year, with provisions for cogeneration and new upgrading capacity. The details of how this emissions limit will be implemented have not been finalized.

Actual costs to Harvest and its industry partners cannot be determined with certainty until output-based regulations are defined and standards published. Further details are expected from the AER in 2016 which will allow for detailed regulatory planning and the creation of cost estimates for compliance in 2017.

British Columbia

The British Columbia government released its Climate Leadership Plan Discussion Paper in July 2015. After considering the feedback provided during the consultation period, the B.C. Climate Leadership Team released its Recommendations to Government in early 2016. The 32 recommendations focus largely on carbon pricing and measures to reduce GHG emissions, including increasing the rate of the existing carbon tax by $10/tonne every year starting in July 2018, expanding the scope of the carbon tax to apply to all GHG emission sources (including non-combustion sources), as well as implementing targeted measures to protect emissions-intensive, trade-exposed sectors (e.g. refining industry). The B.C. government is currently conducting additional consultation on the Climate Leadership Plan and expects to release the final plan in the spring of 2016.

This existing carbon tax in British Columbia is on the purchase or use of fossil fuels within the Province of British Columbia. The current tax rate is $30 per tonne of CO2e emissions. 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 Act") 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 2015, the cost to Harvest to comply was approximately $75,000 which included the GHG inventory and third party verification as required by the regulation.

Saskatchewan

The Management and Reduction of Greenhouse Gases Act received Royal Assent 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.

Land Use

In response to Alberta's growth over the past 10 years, the Government of Alberta 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 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 new conservation areas did not affect Harvest.

The second regional plan, South Saskatchewan Regional Plan ("SSRP"), became effective September 1, 2014. Similar to the LARP, the regional plan establishes new conservation areas and environmental limits, protect water supply and provide clarity about land use and access. The proposed new conservation areas have no impact on Harvest.

The Government of Alberta is now commencing development of the North Saskatchewan Regional Plan ("NSRP"). The NRSP is located in central Alberta and the first phase of public consultation is complete. Harvest will continue to monitor the development of the NRSP to determine if it will have a material impact on Harvest's current or future operations in this region.

Harvest commits to comply with all regulatory requirements associated with the land-use framework in which it operates and to meet the requirements outlined by the AER.

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. None of 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 was proposed 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. In 2013, the Government of Alberta created the Protecting Alberta's Environment Act (the "Act") wherein it established the Alberta Environmental Monitoring and Evaluation and Reporting Agency (AEMERA). This agency is responsible for all regional environmental monitoring within Alberta including the Monitoring Plan. Since 2013, the Government of Alberta has levied annual Monitoring Plan fees to oil sands industry members including Harvest as per the Act. The Monitoring Plan budget is approximately $50 million annually and Harvest continues to meet its obligation to fund its portion of the Monitoring Plan as required by the Act. The Monitoring Plan has been phased in over a three-year period and will continue operation under the management of AEMERA.

Project specific environmental monitoring requirements for the BlackGold Project (the "Project") which have been set out in the Project Environmental Protection and Enhancement Act Approval are also being managed. The Project is required to conduct monitoring, mitigation and reporting during construction, operation, and reclamation activities. Harvest continues to meet its ongoing environmental monitoring, mitigation and reporting requirements.

Abandonment and Reclamation

Alberta

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 that its deemed liabilities exceed its deemed assets. 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. The 2013 updates would be implemented over three years, changing how both assets and liabilities were calculated. In addition to the changes in the LLR program, the AER released the Licensee Liability Rating Program Management Plan (LLRPM). This management plan allows operators whose liabilities exceed its assets and who have been issued abandonment orders due to unpaid financial securities to enter a plan to reduce liability. Under the management plan, a licensee may pay outstanding security amounts by quarterly payments, subject to meeting certain obligations. Those obligations include providing detailed financial information to the AER and submitting plans to abandon and reclaim outstanding, inactive wells. As of April 12, 2016 a total of 66 operators had entered the management plan, of which 36 have achieved successful plan exit.

On July 4, 2014, the AER introduced the inactive well compliance program (the "IWCP") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("Directive 013"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee will be required to bring 20 percent of its IWCP inventory into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. In recent year, Harvest has seen a direct increase in the volume of surface abandonments and new reclamation activity due to the implementation of the IWCP program.

<u>British Columbia</u>

In British Columbia, the commission implements the Liability Management Rating ("LMR") Program, designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the LMR Program, the commission determines the required security deposits for permit holders. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the Oil and Gas Activities Act. Harvest maintains the desired LMR ratio in British Columbia; hence, this criterion did not have a material impact on Harvest's operations in 2015.

<u>Saskatchewan</u>

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. Harvest's liability ratio in Saskatchewan weakened in 2015 because of reduced drilling activity in the year. Harvest will continue to monitor its Saskatchewan liability ratio closely in 2016.

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 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 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) 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.

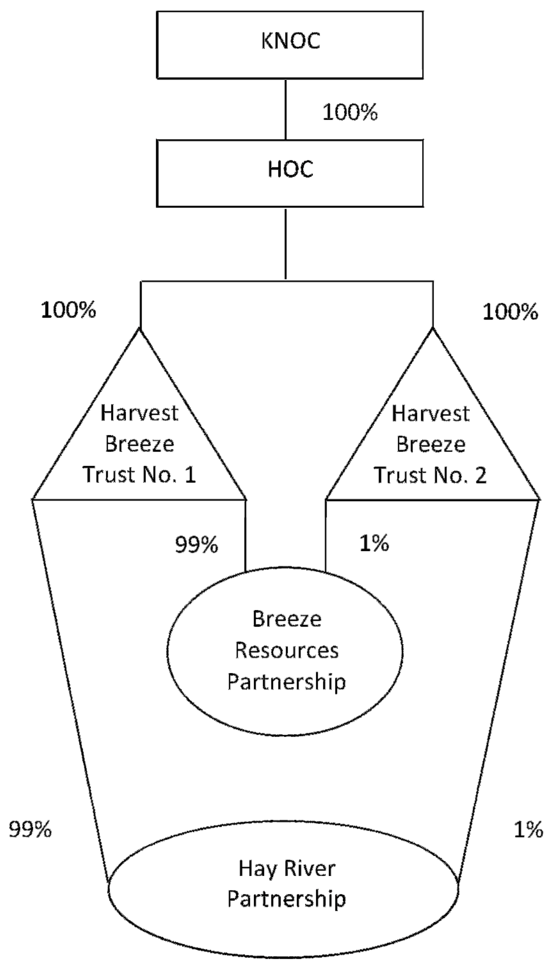
Hay River Partnership, a general partnership

Hay River Partnership (indirectly wholly-owned by Harvest) 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.

Discontinued Operations

On November 13, 2014, North Atlantic was sold. North Atlantic Refining Limited was incorporated under the laws of the Province of Newfoundland and Labrador on November 17, 1986. North Atlantic was a wholly owned subsidiary of Harvest, with assets consisting of the Refinery and related retail marketing assets. North Atlantic was 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, 2015:



Harvest also has investments in joint ventures. Please see "Deep Basin and HK MS Partnerships" section in Item 4.

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 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.

	2015 Gross Annual Production				
	Light & Medium Crude Oil	Heavy Oil	Natural Gas	NGLs	Total Gross Production
Material Area	Mbbl	Mbbl	Mmcf	Mbbl	Mboe
Hay River	—	1,585	—	5	1,590
Red Earth	1,235	—	123	21	1,277
West Central Alberta	277	72	15,598	1,065	4,013
East Central Alberta	582	217	868	29	973
Deep Basin	22	—	17,105	237	3,110
Heavy Oil	—	1,804	472	24	1,907
Saskatchewan Light Oil	745	—	21	—	749
Other	339	447	4,598	63	1,614
Total	3,200	4,125	38,785	1,444	15,233

	2015 Annual Production				
	Light & Medium Crude Oil	Heavy Oil	Natural Gas	NGLs	Total Production
Material Area	Mbbl	Mbbl	Mmcf	Mbbl	Mboe
Hay River	—	1,429	—	4	1,433
Red Earth	1,094	—	113	18	1,131
West Central Alberta	245	65	14,337	921	3,620
East Central Alberta	516	196	798	25	869
Deep Basin	19	—	15,722	205	2,845
Heavy Oil	—	1,626	434	21	1,719
Saskatchewan Light Oil	660	—	19	—	664
Other	301	401	4,226	54	1,461
Total	2,835	3,717	35,649	1,248	13,742

	2014 Annual Gross Production				
Material Area	Light & Medium Crude Oil Mbbl	Heavy Oil Mbbl	Natural Gas Mmcf	NGLs Mbbl	Total Gross Production Mboe
Hay River	—	1,664	—	6	1,670
Red Earth	1,340	—	45	30	1,377
West Central Alberta	361	95	16,956	1,211	4,493
East Central Alberta	918	853	1,538	52	2,078
Deep Basin	15	—	10,986	204	2,049
Heavy Oil	—	2,289	316	22	2,364
Saskatchewan Light Oil	809	—	23	—	812
Other	397	535	5,272	69	1,883
Total	3,840	5,436	35,136	1,594	16,726

	2014 Annual Production				
Material Area	Light & Medium Crude Oil Mbbl	Heavy Oil Mbbl	Natural Gas Mmcf	NGLs Mbbl	Total Production Mboe
Hay River	—	1,417	—	5	1,470
Red Earth	1,126	—	42	26	1,212
West Central Alberta	303	81	15,911	1,039	3,954
East Central Alberta	771	726	1,443	45	1,829
Deep Basin	13	—	10,309	175	1,803
Heavy Oil	—	1,949	297	19	2,080
Saskatchewan Light Oil	680	—	22	—	715
Other	333	456	4,947	59	1,655
Total	3,226	4,629	32,971	1,368	14,718

	2013 Annual Gross Production				
Material Area	Light & Medium Crude Oil Mbbl	Heavy Oil Mbbl	Natural Gas Mmcf	NGLs Mbbl	Total Gross Production Mboe
Hay River	—	1,889	86	8	1,912
Red Earth	1,197	—	45	21	1,226
West Central Alberta	541	115	19,140	1,443	5,288
East Central Alberta	1,042	1,332	1,403	58	2,665
Deep Basin	23	—	13,388	331	2,586
Heavy Oil	—	2,284	414	9	2,362
Saskatchewan Light Oil	1,027	—	87	4	1,045
Other	430	550	6,066	77	2,069
Total	4,260	6,170	40,629	1,951	19,153

	2013 Annual Production				
Material Area	Light & Medium Crude Oil Mbbl	Heavy Oil Mbbl	Natural Gas Mmcf	NGLs Mbbl	Total Production Mboe
Hay River	—	1,589	81	7	1,681
Red Earth	1,007	—	42	18	1,078
West Central Alberta	455	97	18,020	1,251	4,650
East Central Alberta	877	1,120	1,321	50	2,344
Deep Basin	19	—	12,605	287	2,274
Heavy Oil	—	1,921	390	8	2,077
Saskatchewan Light Oil	864	—	82	3	919
Other	363	463	5,712	68	1,819
Total	3,585	5,190	38,253	1,692	16,842

Hay River

Hay River was acquired by Harvest on August 2, 2005 and is located approximately 245 miles north west of Grande Prairie in north-eastern British Columbia. In 2015, Hay River produced an average of gross 4,355 boe/day of 24º API crude oil (including 12 barrels per day of condensate removed from the solution gas stream before that solution gas is reinjected into the reservoir for pressure maintenance) from the Bluesky formation located at a depth of approximately 350 metres. Natural gas produced from this formation, along with produced water, is 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 2015, Harvest drilled 9 gross 100% Working Interest wells, including 7 horizontal producing wells, 2 water injection wells. Our total Hay capital program for 2015 was $20.9 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 recovery and reinjection 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 200 miles north west of Edmonton, Alberta. Production in 2015 from Red Earth averaged gross 3,499 boe/d (97% oil), with an average oil quality of 37° to 39° API from the Slave Point, Granite Wash and Gilwood formations.

Production is gathered via Harvest's gathering system and the oil is pipelined to market via the Plains Rainbow Pipeline system.

Harvest continued to build on its 2012 partnership with the Loon Lake First Nations for an option on up to 26 sections of land, by drilling 6 wells in Loon Lake in 2015. All wells were horizontal wells in the Slave Point formation using multi-staged fractured completions.

Our total Red Earth capital program in 2015 was $25.5 million.

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 production area with some oil production. Production in 2015 for the region averaged gross 10,996 boe/d (65% gas).

Gas gathering, transportation, compression and processing infrastructure is extensive in West Central Alberta and Harvest uses a combination of Harvest's and third party's infrastructures to process and transport its gas and NGLs to market.

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 formation.

In 2015, Harvest participated in 3 gross wells and 0.2 net wells. Total capital expenditure throughout the area was approximately $5.0 million mainly associated with the upkeep of the existing infrastructure as well as some abandonment and reclamation work.

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 generally over 90%. In 2015, the average production was gross 2,666 boe/d (82% oil) and is primarily heavy and medium oil from 18o to 32o API. The Corporation's largest group of legacy properties including Bashaw, Bellshill and a number of smaller oilfields are in the region. This area remains largely focused on cost savings and optimization of current wells and facilities. Harvest continues to invest in pipeline and infrastructure upgrades to repair or replace some of the older equipment in East Central Alberta. Harvest drilled no wells in 2015 in East Central Alberta.

During the year of 2015 Harvest divested Bashaw, Leahurst, Redwater, Metiskow and Czar properties.

Total capital investment in East Central Alberta was approximately $11.3 million in 2015 primarily related to investments in pipeline and facility upgrades.

Deep Basin (Consolidated Entities)

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

Production in 2015 averaged gross 8,520 boe/d (92% gas). Harvest saw significant production growth in production volumes during 2015, as the result of increased capital investment tied to new expanded processing and transportation agreement.

Legacy production is from vertical wells completed in multiple zones (Falher, Cardium, Cadotte, Cadomin, Bluesky, Dunvegan, and Gething) and comingled together. Recent drilling activities have been focused on drilling high rate 5 to 10 mmcf/d, stage-stimulated horizontal wells in the Falher formation. In 2015, Harvest participated in 7 gross (3.1 net) wells and added to its land base and expanded its gathering system infrastructure for a net investment of $62.6 million.

Heavy Oil

Harvest has various working interests in this area, which is located near the town of Lloydminster on the Alberta side of the border and down into Southern Alberta near the city of Medicine Hat. Major properties in this group include Suffield (Glauconite), Lindbergh/Wildmere (Lloyd/Sparky/GP), 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 gross 5,225 boe/d (96% oil) in 2015. Harvest drilled 1 gross well in 2015 in the Suffield area, and invested in pipeline and facility upgrades with total net capital expenditures of $0.7 million.

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

Saskatchewan Light Oil

This area includes Harvest's assets in southeast Saskatchewan towards the Manitoba border. The southeast 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 2015 averaged gross 2,052 boe/d of light oil. In 2015 capital expenditure totaled $4.6 million primarily related capital maintenance and facilities.

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 2015 the construction had been substantially completed, including the building of the CPF plant site, well pads, connecting pipelines and several systems have since been commissioned. Total capital expenditure of $66.0 million was incurred in 2015.

Harvest's plans for 2016 are to continue with minor pre-commissioning activities and then decide whether or not to proceed to commissioning and steam injection depending on the price outlook for bitumen.

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

Deep Basin Partnership (Equity Investment)

In April 2014 Harvest entered into two Partnerships with KERR to build a gas plant and develop our natural gas assets in the Bilbo, Karr and Wapiti regions of the Deep Basin Partnership area. Activities and results from these partnerships are reported on an equity basis in Harvest's financial statements.

The partnership saw significant production growth in production volumes during 2015, as the result of increased capital investment. Production for 2015 in the DBP averaged 4,126 boe/d, and Harvest's equity interest in the production was 3,319 boe/d. During 2015, DBP drilled 7 gross (6.27 net) wells in the Deep Basin, targeting the Cardium, Falher and Montney formations. Production from these wells is directed to the Harvest-operated Partnership gas plant. Total capital investment by the partnership in 2015 was $139.0 million.

2016 CAPITAL EXPENDITURE PLAN

The primary areas of focus for Harvest's Upstream and BlackGold capital program during 2016 are the following:

- BlackGold – Continue minor pre-commissioning activities ;
- Hay River – Optimize existing production by cleaning out some wellbores of accumulated mud from prior year's drilling;
- Deep Basin Area (including Deep Basin Partnership Area) – Participate in two partner operated drills during the winter of 2015/16 and drill and case two Montney wells inside the DB Partnership for completion and tie-in in 2017.

Harvest plans to fund future capital expenditures through borrowings from the Amended Credit Facility, 2015 KNOC loan and cash from operating activities. For further discussion regarding Harvest's liquidity and capital resources, please refer to Item 5B.

Incremental Exploitation and Development Potential

Management of Harvest has identified numerous development opportunities, many of which provide the potential for capital investment and incremental production beyond that identified in the Reserves Reports. These opportunities include:

- Implementation or optimization of enhanced water floods in selected pools such as Hay River, Red Earth and Cecil resulting in increased production and recovery;
- 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 across most of Harvest's core properties 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 and high operating cost wells currently shut in due to low commodity prices to preserve reserves to be produced at a time when 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), Deep Basin (Falher and Montney Formations) and Rimbey/West Central Area (Cardium, Glauconite, Viking, Ostracod, Notikewin, Wilrich Formations).

OTHER

For further information on environmental issues that may affect the utilization of the Upstream assets, please see Item 3D "Risk Factors'' and Item 4B "Business Overview - Environmental Regulations". The Corporation's Amended Credit Facility is secured by a first floating charge over all of the assets of Harvest and its material subsidiaries. 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, 2015 as set out in this annual report under Item 18.

A. Operating Results

CONTINUING OPERATIONS

UPSTREAM

Summary of Financial and Operating Results

	Year Ended December 31		
(in millions except where noted)	**2015**	2014	2013
FINANCIAL			
Petroleum and natural gas sales [1]	**510.3**	1,046.0	1,101.7
Royalties	**(48.7)**	(149.7)	(153.9)
Loss from joint ventures	**(97.3)**	(4.7)	—
Revenues and other income[2]	**364.3**	891.6	947.8
Expenses			
Operating	**251.5**	330.5	345.6
Transportation and marketing	**5.2**	17.5	22.6
Realized losses (gains) on derivative contracts[3]	**4.4**	1.4	(4.9)
Operating netback after hedging[4]	**103.2**	542.2	584.5
General and administrative	**57.7**	64.8	68.1
Depreciation, depletion and amortization	**418.1**	435.2	530.0
Exploration and evaluation	**27.5**	10.2	12.3
Impairments[7]	**765.3**	267.6	24.1
Unrealized losses on derivative contracts[5]	**0.8**	0.7	0.5
Loss (gains) on disposition of assets	**1.7**	(47.5)	(33.9)
Operating loss[2]	**(1,167.9)**	(188.8)	(16.6)
Capital asset additions (excluding acquisitions)	**146.5**	408.5	322.3
Property and business acquisitions (dispositions), net	**(78.7)**	(301.1)	(155.6)
Decommissioning and environmental remediation expenditures	**(15.6)**	(14.0)	(19.6)
OPERATING			
Light to medium oil (bbl/d)	**8,768**	10,520	11,671
Heavy oil (bbl/d)	**11,301**	14,893	16,905
Natural gas liquids (bbl/d)	**3,956**	4,368	5,345
Natural gas (mcf/d)	**106,259**	96,265	111,313
Total (boe/d)[6]	**41,735**	45,825	52,473

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

(2) This is an additional GAAP measure; please refer to "Additional GAAP Measures" in this annual report.

(3) Realized losses (gains) on risk management contracts include the settlement amounts for power, crude oil, natural gas (2014 and 2015 only) and foreign exchange derivative contracts, excluding the effective portion of realized gains from Harvest's designated accounting hedges. See "Risk Management, Financing and Other" section of this annual report for details.

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

(5) Unrealized 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.

(6) Excludes volumes from Harvest's equity investment in the Deep Basin Partnership.

(7) Includes $570.3 million Upstream assets impairments and $195 million goodwill impairment for the year ended 2015.

Commodity Price Environment

	Year Ended December 31		
	2015	2014	2013
West Texas Intermediate ("WTI") crude oil (US$/bbl)	**48.8**	93.00	97.97
West Texas Intermediate crude oil ($/bbl)	**62.13**	102.49	100.95
Edmonton light sweet crude oil ("EDM") ($/bbl)	**57.2**	94.59	93.04
Western Canadian Select ("WCS") crude oil ($/bbl)	**44.85**	81.06	74.97
AECO natural gas daily ($/mcf)	**2.69**	4.49	3.17
U.S. / Canadian dollar exchange rate	**0.783**	0.905	0.971

Differential Benchmarks			
EDM differential to WTI ($/bbl)	4.93	7.90	7.91
EDM differential as a % of WTI	7.9%	7.7%	7.8%
WCS differential to WTI ($/bbl)	17.28	21.43	25.98
WCS differential as a % of WTI	27.8%	20.9%	25.7%

The average WTI benchmark price decreased 48% year ended December 31, 2015 as compared to the same period in 2014. The average Edmonton light sweet crude oil price ("Edmonton Light") decreased 40% for the year ended December 31, 2015 compared to 2014, mainly due to the decrease in the WTI price, partially offset by the strengthening of the U.S. dollar against the Canadian dollar and the movement of the Edmonton light sweet differential.

Heavy oil differentials fluctuate based on a combination of factors including the level of heavy oil production and inventories, pipeline and rail capacity to deliver heavy crude to U.S. and offshore markets and the seasonal demand for heavy oil. The changes in the WCS price for year ended December 31, 2015 as compared to the same period in 2014 were mainly the result of the decrease in the WTI price and the widening of the WCS differential to WTI, partially offset by the strengthening of the U.S. dollar against the Canadian dollar.

Realized Commodity Prices

	Year Ended December 31		
	2015	2014	2013
Light to medium oil prior to hedging ($/bbl)	**49.59**	87.65	85.38
Heavy oil prior to hedging ($/bbl)	**42.69**	78.59	74.37
Natural gas liquids ($/bbl)	**29.36**	59.53	57.44
Natural gas prior to hedging($/mcf)	**2.62**	4.82	3.46
Average realized price prior to hedging ($/boe) (1)	**32.33**	62.24	56.58
Light to medium oil after hedging ($/bbl)(2)	**49.59**	87.65	85.38
Heavy oil after hedging ($/bbl)(2)	**45.71**	80.55	73.84
Natural gas after hedging ($/mcf)(2)	**2.74**	4.60	3.63
Average realized price after hedging ($/boe)(1)(2)	**33.45**	62.41	56.78

(1) Inclusive of sulphur revenue.
(2) Inclusive of the realized gains (losses) from contracts designated as hedges. Foreign exchange swaps and power contracts are excluded from the realized price.

Harvest's realized prices prior to hedging for light to medium oil generally trend with the Edmonton Light benchmark price. Harvest's realized prices prior to hedging for heavy oil are a function of both the WCS and Edmonton Light benchmarks due to a portion of our heavy oil volumes being sold based on a discount to the Edmonton Light benchmark. 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.

Harvest's realized prices prior to any hedging activity for natural gas generally trend with the AECO benchmark prices. For the twelve months ended December 31, 2015, the realized gas price prior to hedging decreased by 46%, while the AECO benchmark decreased by 40% as compared to the same period in 2014. The further decrease in Harvest's realized natural gas price prior to hedging for the full year 2015 is due to the reclassification of gas transportation costs to gas revenues starting in the fourth quarter of 2014.

Realized natural gas liquids prices decreased by 51% for the year ended December 31, 2015, as compared to the same periods in the prior year. The decrease is consistent with the decrease in oil prices. Realized natural gas liquids prices increased by 4% from 2013 to 2014, which reflected the change in the natural gas liquid s commodity prices.

In order to partially mitigate the risk of fluctuating cash flows due natural gas pricing and heavy oil pricing volatility, Harvest had WCS and AECO derivative contracts in place for a portion of its production during the years ended December 31, 2015, 2014 and 2013. For the year ended December 31, 2015, the WCS hedge increased our heavy oil price by $3.02/bbl (2014 – increased by $1.96/bbl, 2013 – decreased $0.53/bbl).

Including the impact from the AECO hedges, Harvest's realized natural gas price for the year ended December 31, 2015 increased by $0.12/mcf (2014 – decrease by $0.22/mcf, 2013 – increased $0.17/mcf).

Sales Volumes

	Year Ended December 31					
	2015		2014		2013	
	Volume	**Weighting**	Volume	Weighting	Volume	Weighting
Light to medium oil (bbl/d)	**8,768**	**21%**	10,520	23%	11,671	22%
Heavy oil (bbl/d)	**11,301**	**27%**	14,893	32%	16,905	32%
Natural gas liquids (bbl/d)	**3,956**	**9%**	4,368	10%	5,345	10%
Total liquids (bbl/d)	**24,025**	**57%**	29,781	65%	33,921	64%
Natural gas (mcf/d)	**106,259**	**43%**	96,265	35%	111,313	36%
Total oil equivalent (boe/d)	**41,735**	**100%**	45,825	100%	52,473	100%

2015-2014

Total sales volumes were 41,735 boe/d for the year ended December 31, 2015, a decrease of 4,090 boe/d as compared to 2014. The decrease was primarily due to dispositions of certain non-core producing properties during 2015 and 2014, third party outages that restricted our gas and NGL production in the Deep Basin and West Central Alberta in 2014 and natural declines exceeding the volume additions from our drilling program.

Harvest's average daily sales of light to medium oil decreased 17% for year ended December 31, 2015, as compared to the same period in 2014. The decreases were due to natural declines and the disposition of non-core properties, partially offset by the results of our 2014/2015 drilling program.

Heavy oil sales for year ended December 31, 2015 decreased by 24%, as compared to 2014 mainly due to non-core asset dispositions in the fourth quarter of 2015 and the third quarter of 2014, and natural declines, partially offset by the results of our 2014/2015 drilling program.

Natural gas sales during the year ended December 31, 2015 increased 10%, as compared to 2014. The increases were mainly a result of Harvest's 2014/2015 drilling program and the acquisition of Hunt during the first quarter of 2015, partially offset by natural declines and the disposition of assets to the Deep Basin Partnership during the fourth quarter of 2015.

Natural gas liquids sales for the year ended December 31, 2015 decreased by 9% from 2014 due to third party facility constraints, disposition of assets to the Deep Basin Partnership during the fourth quarter of 2015 and natural declines, partially offset by results from Harvest's 2014/2015 drilling program and the acquisition of Hunt during the first quarter of 2015.

2014-2013

Total sales volumes were 45,825 for the year ended December 31, 2014, a decrease of 6,648 boe/d as compared to 2013. The decrease was primarily due to the disposition of assets to the Deep Basin Partnership (accounted for as an equity investment) and dispositions of certain non-core producing properties during 2013 and 2014, third party outages that restricted our gas and

NGL production in the Deep Basin and West Central Alberta in 2014 and natural declines exceeding the volume additions from our drilling program.

Harvest's 2014 light to medium oil sales decreased 10% from 2013 to 10,520 bbl/d. The decrease was primarily due to natural declines and the disposition of non-core properties, partially offset by the results of our 2013 and 2014 drilling activity.

Heavy oil sales for the year ended December 31, 2014 decreased 12% as compared to 2013 mainly due to non-core asset dispositions in the third quarter of 2014 (see the "Property Dispositions" section under this item), previous dispositions and natural declines.

Natural gas sales during the year ended December 31, 2014 decreased 14% as compared to 2013. The decrease was mainly due to natural declines, third-party processing facility constraints, disposition of assets to the Deep Basin Partnership during the second quarter of 2014 and disposition of non-core assets during 2013, partially offset by the results of our 2013 and 2014 drilling activity.

Natural gas liquids sales for the year ended December 31, 2014 decreased by 18% from 2013 for reasons consistent with natural gas sales.

Revenues

	Year Ended December 31		
($ millions)	**2015**	2014	2013
Light to medium oil sales	**158.7**	336.6	363.7
Heavy oil sales after hedging(1)	**188.6**	437.9	455.6
Natural gas sales after hedging(1)	**106.3**	161.6	147.6
Natural gas liquids sales	**42.4**	94.9	112.1
Other(2)	**14.3**	15.0	22.7
Petroleum and natural gas sales	**510.3**	1,046.0	1,101.7
Royalties	**(48.7)**	(149.7)	(153.9)
Revenues	**461.6**	896.3	947.8

(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, 2015, total petroleum and natural gas sales decreased by 51% as compared to 2014, mainly due to the 46% decrease in realized prices after hedging activities and the 9% decrease in sales volumes. For the year ended December 31, 2014, total petroleum and natural gas sales decreased by 5% as compared to 2013, mainly due to the 13% decrease in sales volumes, partially offset by the 10% increase in realized prices after hedging activities.

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 Crown royalties are based on various sliding scales dependent on incentives, production volumes and commodity prices. Each province has various incentive programs in place to promote drilling by reducing the overall royalty expense for production and offsetting gathering processing costs. In most cases, the incentive period lasts for a finite period of time, after which point the royalty rate generally increases depending on production rates and the market commodity prices.

In January of 2016, the provincial government of Alberta announced the key highlights of a proposed Modernized Royalty Framework that will be effective on January 1, 2017 based on the royalty review panel's recommendations. The highlights include providing royalty incentives for efficient development of conventional crude oil, natural gas and natural gas liquids resources, no changes to the royalty structure of wells drilled prior to 2017 for a period of ten years from the enactment, the replacement of royalty credits/holidays on conventional wells by a revenue minus cost framework with a post-payout royalty rate based on commodity prices, the reduction of royalty rates for mature wells and a neutral internal rate of return for any given play compared to the current royalty framework. Details of the Modernized Royalty Framework have not been released by the Alberta government however the changes are not currently expected to have a material impact on the company's results of operations.

For the year ended December 31, 2015, royalties as a percentage of gross revenue averaged 9.5% (2014 – 14.3%, 2013 – 14.0%). The decrease in royalties as a percentage of gross revenue was mainly due to lower commodity prices.

Operating and Transportation Expenses

	For the Year Ended December 31					
($ millions)	**2015**	**$/boe**	2014	$/boe	2013	$/boe
Power and purchased energy	**48.2**	**3.16**	67.6	4.04	89.1	4.65
Repairs and maintenance	**38.4**	**2.52**	53.2	3.18	51.6	2.70
Well servicing	**19.5**	**1.28**	39.6	2.37	49.9	2.60
Processing and other fees	**29.9**	**1.96**	38.2	2.28	36.8	1.92
Lease rentals and property tax	**33.3**	**2.19**	38.8	2.32	37.3	1.95
Labour - internal	**26.4**	**1.73**	30.9	1.85	31.8	1.66
Chemicals	**17.8**	**1.17**	19.9	1.19	18.7	0.98
Labour - contract	**13.0**	**0.85**	14.2	0.85	15.3	0.80
Trucking	**7.4**	**0.48**	13.8	0.82	13.9	0.72
Other(1)	**17.6**	**1.16**	14.3	0.86	1.2	0.07
Total operating expenses	**251.5**	**16.50**	330.5	19.76	345.6	18.05
Transportation and marketing	**5.2**	**0.34**	17.5	1.05	22.6	1.18

(1) Other operating expenses include Environmental, Health and Safety (2015 – $7.4 million, 2014 – $12.2 million, 2013 – $9.5 million), insurance and accruals.

Operating expenses for the year ended December 31, 2015 decreased by $79 million compared to the same period in 2014, mainly attributable to the decrease in the cost of power, the reduced level of well servicing and repairs and maintenance activity, decrease in the processing and other fees, and the impact of asset dispositions. Operating costs for the 2015 year on a per barrel basis decreased by 16% to $16.50 primarily due to lower spending and lower power prices, partially offset by lower sales volumes.

Operating expenses for 2014 decreased by $15.1 million compared to 2013, mainly due to the decrease in the cost of power, lower well servicing expenses and the impact of asset dispositions in 2013 and 2014. Operating costs for the 2014 year on a per barrel basis increased by 9% to $19.76 primarily due to the impact of lower sales volumes.

	Year Ended December 31		
($/boe)	**2015**	2014	2013
Power and purchased energy costs	**3.16**	4.04	4.65
Realized losses (gain) on electricity risk management contracts	**0.27**	0.10	(0.16)
Net power and purchased energy costs	**3.43**	4.14	4.49
Alberta Power Pool electricity price ($/MWh)	**33.41**	49.63	79.95

Power and purchased energy costs, comprised primarily of electric power costs, represented approximately 19% of total operating expenses for the year ended December 31, 2015 (2014 – 20%, 2013 – 26%). The decrease in power and purchased energy costs per boe for the year ended December 31, 2015 as compared to 2014 was primarily due to the lower average Alberta electricity price. The decrease in power and purchased energy costs per boe for the year ended December 31, 2014 as compared to 2013 was also primarily due to the lower average Alberta electricity price.

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)

	Year Ended December 31		
($/boe)	**2015**	2014	2013
Petroleum and natural gas sales prior to hedging(2)	**32.33**	62.24	56.58
Royalties	**(3.19)**	(8.95)	(8.04)
Operating expenses	**(16.50)**	(19.76)	(18.05)
Transportation and marketing	**(0.34)**	(1.05)	(1.18)
Operating netback prior to hedging(1)	**12.30**	32.48	29.31
Hedging gain(3)	**0.82**	0.10	0.47
Operating netback after hedging(1)	**13.12**	32.58	29.78

(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 gain includes the settlement amounts for natural gas, crude oil, foreign exchange 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, 2015 was $12.30/boe, a decrease of 62% compared to 2014 mainly due to lower average realized prices, partially offset by lower royalties and operating expense per boe. Operating netback prior to hedging for 2014 was $32.48/boe, an increase of $3.17/boe from 2013 mainly due to higher average realized prices, partially offset by higher royalties and operating expenses per boe.

General and Administrative ("G&A") Expense

	Year Ended December 31		
	2015	2014	2013
G&A ($ millions)	**57.7**	64.8	68.1
G&A ($/boe)	**3.79**	3.88	3.56

For the year ended December 31, 2015, G&A expenses net of capitalized G&A decreased $7.1 million, while gross G&A expenses decreased $11.0 million, respectively. The decrease in the G&A expenses from the same period in the prior year were mainly due to lower salaries, benefits, travel, consultants and office rent. The reduction in capitalized G&A is mainly related to reduced capital spending and staffing in 2015. For the year 2014, G&A expenses decreased by $3.3 million compared to 2013 primarily due to decreased consulting costs. 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		
	2015	2014	2013
DD&A ($ millions)	**418.1**	435.2	530.0
DD&A ($/boe)	**27.45**	26.02	27.67

DD&A expense for the year ended December 31, 2015 decreased by $17.1 million as compared to the prior year, mainly due to lower sales volumes in 2015 as well as impairment of certain assets during the years ended December 31, 2014 and 2015, partially offset by the decrease in reserves at December 31, 2015. DD&A expense for the year ended December 31, 2014 decreased by $94.8 million as compared to the prior year, mainly due to a change in Harvest's DD&A accounting estimate in the fourth quarter of 2013, combined with lower sales volumes in 2014, partially offset by the decrease in reserves at December 31, 2014.

Impairment of Property, Plant and Equipment

Impairment is recognized when the carrying value of an asset or group of assets exceeds it recoverable amount, defined as the higher of its value in use ("VIU") or fair value less costs of disposal ("FVLCD"). The Company used a risk adjusted discount rate that varied based on the nature of the assets held in each cash generating unit ("CGU") to determine the fair value at the measurement date.

At December 31, 2015 the Company tested all its Upstream CGUs for impairment as a result of decreases in the outlook of future commodity prices compared to those at December 31, 2014 and less than expected operating results. The recoverable amounts were based on the assets' FVLCD estimated using the net present value of pre-tax cash flows from oil and gas reserves, based on the reserve values estimated by independent reserve evaluators, and the estimated fair value of undeveloped land. A discount rate in the range of 11% - 16.5% was used to determine the recoverable amount of $968.8 million for the CGUs impaired during the year. A 200 basis point increase in the discount rate would result in an additional $60 million of impairment for oil CGUs and $8 million increase in gas CGUs. A 10% decrease in forward commodity prices would result in additional impairment of $193 million for oil CGUs and $32 million for gas CGUs.

In addition, the sale of certain Upstream oil and gas assets in the Willesden Green area closed on February 1, 2016, so these assets were classified as assets held for sale at December 31, 2015. As a result of this classification, the assets were tested for impairment and written down to their recoverable amount of nil.

For the year ended December 31, 2015, Harvest recognized an impairment loss on its Upstream assets of $570.3 million for all except for two out of the sixteen CGUs. This amount includes the impairments discussed above, as well as impairments from the previous quarters. Impairment in the South Oil CGU at March 31, 2015 was triggered by reserves write-downs as a result of a decline in oil prices combined with underperforming assets. Impairments in West Alberta Gas and South Alberta Gas CGUs at June 30, 2015 were triggered by a decline in gas prices while the East Central Oil CGU impairment was triggered by revised estimated capital costs in the Bellshill area. Impairment in the third quarter of 2015 was triggered primarily by a decline in oil prices. The recoverable amounts were determined in the same manner as noted above for December 31, 2015 impairment calculations.

For the year ended December 31, 2014, Harvest recognized an impairment loss of $267.6 million against PP&E relating to the North Alberta light oil (2014 – $131.8 million, 2013 – $nil, 2012 – $nil), East Saskatchewan light oil (2014 – $100.8 million, 2013 – $nil, 2012 – $nil) and South Alberta gas (2014 – $35.0 million, 2013 – $24.1 million, 2012 – $21.8 million) CGUs. Impairment in the oil CGUs was triggered by reserves write-downs as a result of a decline in the short-term oil prices and reduced estimates of recoverable oil from the CGUs. Impairment in the gas CGU in 2014 was triggered by a reserves write-down as a result of lower forecast development activities and a decline in the long-term gas prices. 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% for the gas CGU and 10% for oil CGUs.

For the year ended December 31, 2013, Harvest recognized an impairment loss of $24.1 million against 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%.

The impairments discussed above may be reversed, if and when the fair values of the CGUs increase in future periods. Any asset impairment that is reversed is recoverable to its original value less any associated DD&A expense. The results of the impairment tests conducted during the year ended December 31, 2015 are sensitive to changes in any of the key management judgments and estimates inherent in the calculations. These judgments and estimates include revisions in reserves or resources, a change in forecast commodity prices, expected royalty rates, required future development expenditures, and expected future production costs all of which could increase or decrease the recoverable amount of the assets.

Please refer to note 9 of the December 31, 2015 consolidated financial statements under Item 18 of this annual report for further discussion of impairment.

Property Dispositions & Acquisitions

On October 1, 2015 Harvest disposed of certain gas assets to the Deep Basin Partnership in the amount of $57.5 million for partnership units with $2.0 million loss recognized on the disposition. Please see the "Investments in Joint Arrangements" section in this MD&A for further discussion with respect to the Deep Basin Partnership and HK MS Partnership.

On May 1, 2015, Harvest closed the sale of certain non-core oil and gas assets in Eastern Alberta for approximately $28.4 million in net proceeds.

On February 27, 2015, Harvest closed the acquisition of Hunt by acquiring all of the issued and outstanding common shares for total consideration of approximately $37.1 million ($34.9 million net). Hunt was a private oil and gas company with operations immediately offsetting Harvest's lands and production in the Deep Basin area of Alberta. Harvest acquired approximately

15,000 acres of net undeveloped land and production from the assets was approximately 400 boe/d at the time of acquisition. Please refer to note 7 of the December 31, 2015 consolidated financial statements for further discussion.

Together with other insignificant dispositions of Upstream assets made during the fiscal year of 2015, Harvest recognized a loss of $1.7 million for the year ended December 31, 2015, relating to the de-recognition of PP&E, E&E, goodwill and decommissioning and environmental liabilities. As a result of these dispositions, during the year ended 2015, $121.0 million of PP&E was de-recognized.

During the year ended December 31, 2015, Harvest disposed 20,702 acres of net undeveloped land (2014 – 20,906 acres, 2013 – 54,650 acres).

During the year ended December 31, 2014, Harvest sold certain non-core oil and gas assets in Alberta and Saskatchewan for cash proceeds of $243.0 million. The transactions resulted in a gain of $47.5 million, which is recognized in the consolidated statements of comprehensive loss.

In addition, Harvest also disposed of producing and non-producing assets with a net book value of $81.8 million to the Deep Basin Partnership and $8.4 million of construction assets-in-progress to HKMS in the second quarter of 2014.

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. The transactions resulted in a gain of $33.9 million, which is recognized in the consolidated statements of comprehensive loss.

Capital Asset Additions

	Year Ended December 31		
($ millions)	**2015**	2014	2013
Drilling and completion	**78.0**	235.7	180.9
Well equipment, pipelines and facilities	**50.0**	123.3	100.8
Land and undeveloped lease rentals	**1.9**	15.1	6.6
Geological and geophysical	**2.9**	10.6	14.4
Corporate	**5.6**	14.6	4.6
Other	**8.1**	9.2	15.0
Total additions excluding acquisitions	**146.5**	408.5	322.3

Total capital additions were lower for year ended December 31, 2015 compared to 2014 mainly due to a reduced capital activity for the current year in response to a low commodity price environment.

The following table summarizes the wells drilled in five of our core growth areas, and the related drilling and completion costs incurred in the period. 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 spudded (including survey, lease acquisition and construction costs) and related completion costs may be incurred in a period afterwards, depending on the timing of the completion work.

	Year Ended December 31, 2015		
Area	**Gross Wells**	**Net Wells**	***($ million)***
Deep Basin	7.0	3.0	$ 42.1
Red Earth	6.0	6.0	20.8
Hay River	9.0	9.0	11.6
Western Alberta	3.0	0.2	0.4
Suffield	1.0	1.0	0.9
Other areas	—	—	2.2
Total	**26.0**	**19.2**	**$ 78.0**

	Year Ended December 31, 2014		
Area	**Gross**	**Net**	*($ millions)*
Deep Basin	15.0	8.3	$ 67.8
Red Earth	8.0	7.9	48.8
Hay River	19.0	19.0	34.6
Western Alberta	12.0	3.5	15.7
Cecil	5.0	5.0	11.8
SE Saskatchewan	9.0	9.0	10.9
Heavy Oil	19.0	18.4	17.5
Suffield	7.0	7.0	10.6
Other areas	6.0	4.1	18.0
Total	**100.0**	**82.2**	**$ 235.7**

	Year Ended December 31, 2013		
Area	**Gross**	**Net**	*($ millions)*
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**

2015

The primary areas of focus for Harvest's Upstream 2015 drilling program were as follows:

- Deep Basin – drilled or participated in 7 rig-released horizontal multi-stage fractured wells to develop the liquids-rich Falher and Montney gas formations;
- Red Earth – drilled 6 wells at Loon Lake targeting light oil in the Slave Point formation. All the wells were drilled from one surface location to reduce per well costs. With this approach all surface holes are drilled, followed by the main holes, and then the wells are completed and equipped for production;
- Hay River – drilled 7 producing oil and 2 water injection wells, pursuing slightly heavy (low 20 degree API) gravity oil in the Bluesky formation using multi-leg horizontal oil wells;
- West Central Alberta –participated in 3 wells in the Wilson Creek field with recent efforts targeting the Glauconite formation; and
- Suffield – drilled and abandoned one vertical test well.

Harvest's net undeveloped land additions of 42,988 acres during the year ended December 31, 2015 (2014 – 105,818 acres, 2013 – 50,651 acres) were primarily in our core growth areas.

Please refer to Item 4D "Property, Plant and Equipment – Upstream Material Properties" for discussion of Harvest's drilling activities in 2015 by material properties.

2014

In Red Earth, Harvest was pad drilling 6 wells from one surface location to reduce per well costs. All surface holes were drilled, followed by the main holes, and then the wells were completed and equipped for production. Several surface holes were drilled at Red Earth in the fourth quarter of 2014, but since these wells were not drilled and rig released before December 31, 2014, there were no related well additions in 2014.

The primary areas of focus for Harvest's Upstream drilling program were as follows:

- Deep Basin – participated or drilled horizontal multi-stage fractured wells to develop the liquids-rich Falher and Montney gas formations;
- Red Earth – drilled wells at Loon Lake, Girouxville and Evi targeting light oil in the Slave Point formation;
- Hay River – drilled producing and injection wells, pursuing slightly heavy (low 20 degree API) gravity oil in the Bluesky formation using multi-leg horizontal oil wells;
- West Central Alberta – drilled or participated in wells in several fields with recent efforts targeting the Bluesky, Cardium, Glauconite, and Notikewin formations;
- Cecil – drilled horizontal wells targeting light oil in the Charlie Lake formation;
- SE Saskatchewan – drilled horizontal wells targeting light oil in the Tilston formation;
- Heavy Oil area – drilled horizontal heavy oil wells in the Lloydminster region of Alberta into the Dina, General Petroleum, Lloydminster, McLaren and Sparky formations; and
- Suffield and other areas – drilled light to heavy oil wells in southern Alberta, including Suffield, Enchant and Montgomery.

2013

During 2013, Harvest concentrated 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 were 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.

Decommissioning Liabilities

Harvest's Upstream decommissioning liabilities at December 31, 2015 were $796.6 million (2014 – $752.0 million, 2013 – $709.4 million) for future remediation, abandonment, and reclamation of Harvest's oil and gas properties. The $44.6 million net increase in the liability is mainly a result of the changes in estimated costs and timing from December 31, 2014 to 2015, partially offset by disposals of properties discussed in the "Property Dispositions" section above. The total of the decommissioning liabilities are based on management's best estimate of costs to remediate, reclaim, and abandon 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 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, 2015, Harvest had $149.0 million (2014 – $353.1 million, 2013 – 379.8 million) of goodwill on the balance sheet related to the Upstream segment, a decrease of $204.1 million (2014 - $26.7 million) of which $9.1 million (2014 – $26.7 million) resulted from dispositions of certain oil and gas properties (see the "Property Dispositions" section above) and impairment of $195.0 million was recorded in the fourth quarter of 2015. 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. 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 of Upstream was determined based on its FVLCD.

Market participants generally apply the market multiple enterprise value per barrel of proved and probable reserves ("EV/2P") when estimating the fair value of an oil and gas company. As such, Harvest determined the fair value of its Upstream segment by applying the observed EV/2P multiple of comparable public companies to its proved and probable reserves (Level 2 fair value input). Harvest's proved and probable reserves were estimated by an independent qualified reserves evaluator and are subject to significant judgment. For the year ended December 31, 2015, the EV/2P multiples ranged from $5.90 to $ 10.30 per barrel of proved and probable reserves for a group of comparable companies of similar size and production profile, and Harvest used an average EV/2P multiple of $7.50 per barrel of proved and probable reserves when determining the implied fair value of Harvest's Upstream segment. As at December 31, 2015, the carrying amount exceeded the recoverable amount of the Upstream segment resulting in an impairment of $195 million (2014, 2013 – $nil).

Investments in Joint Arrangements

On April 23, 2014, Harvest entered into the DBP and HKMS joint ventures with KERR, where Harvest contributed selected assets with upside development potential and KERR contributed cash for both infrastructure and development capital. These unique partnerships allow Harvest to grow its core business region while conserving capital. The principal place of operations for both DBP and HKMS is in Canada.

Deep Basin Partnership

DBP was established for the purposes of exploring, developing and producing from certain oil and gas properties in the Deep Basin area in Northwest Alberta. On April 23, 2014, Harvest contributed certain producing and non-producing properties to DBP in exchange for 467,386,000 of common partnership units (82.32% ownership interest), while KERR contributed $100.4 million for 100,368,000 preferred partnership units (17.68% ownership interest). On August 29, 2014, KERR contributed an additional $32.9 million to the DBP for an additional 32,913,506 preferred partnership units increasing KERR's ownership interest to 22.19% and diluting Harvest's ownership interest to 77.81%. On October 1, 2015 Harvest contributed certain gas assets to the DBP in the amount of $57.5 million for partnership units. During the year ended 2015 Harvest also made various cash contributions to the DBP that resulted in increase in its ownership percentage as reflected in the table below.

Amounts contributed by KERR on the formation of the partnership have been spent by the DBP to purchase land, drill and develop partnership properties in the Deep Basin area. As the initial funding from KERR is consumed and additional funds are required to fund the development program, each partner is entitled to participate in and fund the additional work programs, however to the extent only one partner funds, its partnership interest will be increased and the other partner's interest will be diluted proportionately. At December 31, 2015, Harvest received a total of $4.3 million (2014 - $2.3 million, 2013 - $nil) in distributions from the DBP.

The preferred partnership units provide KERR certain preference rights, including a put option right exercisable after 10.5 years, whereby KERR could cause DBP to redeem all its preferred partnership units for consideration equal to its initial contribution plus a minimum after-tax internal rate of return of two percent. If DBP 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 (the "top-up obligation"). This obligation could also arise upon the termination of this arrangement. This top-up obligation is accounted for by Harvest at fair value through profit and loss and is estimated using a probabilistic model of the estimated future cash flows of the DBP. The cash flow forecast is based on management's internal assumptions of the volumes, commodity prices, royalties, operating costs and capital expenditures specific to the DBP. As at December 31, 2015, the fair value of the top-up obligation was estimated as $2.0 million (2014 - $nil, 2013 - $nil), therefore, a top-up obligation was recorded by Harvest. Once KERR achieves the minimum after-tax internal rate of return on its investment, Harvest is entitled to increased return on its investment.

Harvest derives its income or loss from its investment in the DBP based upon Harvest's share in the change of the net assets of the joint venture. Harvest's share of the change in the net assets does not directly correspond to its ownership interest because of contractual preference rights to KERR and changes based on contributions made by either party during the year. For year ended

2015, Harvest recognized a loss of $97.3 million (2014 –$4.7 million, 2013 - $nil) from its investment in the DBP and HKMS joint venture. Harvest's ownership of DBP by quarter was the following:

	As at December 31,	
	2015	2014
Harvest's ownership interest	**81.71%**	77.81%
KERR's ownership interest	**18.29%**	22.19%
Total	**100.00%**	100.00%

Below is an overview of operational and financial highlights of these investments for the year ended December 31, 2015. Unless otherwise noted the following discussion relates to 100% of the joint venture results and not based on Harvest ownership share.

	Year Ended December 31	
	2015	2014 (1)
Natural gas (mcf/d)	**19,135**	6,747
Natural gas liquids (bbl/d)	**936**	394
Light to medium oil (bbl/d)	**1**	2
Total (boe/d)	**4,126**	1,520
Harvest's share(2)	**3,319**	1,183

(1) 2014 year ended period from April 23, 2014 to December 31, 2014

Sales volumes for the year ended December 31, 2015 increased by 2,606 boe/d, as compared to the same periods in 2014. The increase was primarily due to new wells being brought online through the HKMS natural gas processing plant that commenced operations in early 2015 and additional assets contributed on October 1, 2015 by Harvest, partially offset by production curtailments due to third party restrictions.

	Year Ended December 31	
	2015	2014(2)
Revenues	**30.2**	9.9
Operating expenses and Other	**(27.9)**	(3.8)
Depletion, depreciation and amortization	**(43.9)**	(9.0)
Finance costs	**(2.7)**	(1.7)
Impairment	**(59.8)**	-
Net loss(1)	**(104.1)**	(4.6)

(1) Balances represent 100% share of DBP.
(2) 2014 year ended period from April 23, 2014 to December 31, 2014

The higher sales revenues in the year ended 2015 reflect the higher volumes, partially offset by lower commodity prices, and lower royalties compared to the fourth quarter and the period of April 23, 2014 to December 31, 2014.

Operating expenses and other expenses for the year ended 2015 were $18.53/boe, an increase of $8.61/boe from the same period in 2014. The increases from 2014 were mainly due to the requirement to make the minimum monthly capital fee payments to the HK MS Partnership under the Gas Processing Agreement between the DBP and HKMS.

Depletion for the year ended December 31, 2015 was $29.15/boe (2014 – $23.49/boe). The increases from 2014 were mainly due to substantial capital spent combined with an increase in volumes, partially offset by proved reserve additions recognized in the fourth quarter of 2015.

During the fourth quarter of 2015 DBP recognized an impairment loss of $59.8 million (2014 – Nil) against PP&E. At December 31, 2015 the company tested its CGU for impairment primarily as a result of decrease in the outlook of future commodity prices compared to those at December 31, 2014. The recoverable amounts was based on the assets' FVLCD estimated using the net present value of pre-tax cash flows from oil and gas reserves, based on the reserve values estimated by independent reserve evaluators, and the estimated fair value of undeveloped land. The pre-tax discount rate of 11% was used in the test.

	Year Ended December 31	
	2015	2014(2)
Drilling and completion	**64.6**	88.7
Well equipment, pipelines and facilities	**23.4**	17.4
Total (1)	**88.0**	**106.1**

(1) Balances represent 100% share of DBP.
(2) 2014 year ended period from April 23, 2014 to December 31, 2014

During the year ended December 31, 2015 the DBP drilled 7 gross and 6.27 net wells in the Deep Basin (2014 – 9 gross and 9 net wells), targeting the Cadotte, Cardium, Dunvegan, Falher, Halfway and Montney locations. All wells were horizontal, multi-stage fracture stimulated wells targeting liquids rich gas. Production from these wells was processed through the new HKMS gas plant that was completed in early 2015.

HKMS Partnership

HKMS Partnership was formed for the purposes of constructing and operating a gas processing facility, which is 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. For the HKMS Partnership, KERR initially contributed $22.6 million on April 23, 2014 for 22,632,000 partnership units, which represented 34.82% of the outstanding partnership units. On August 29, 2014, KERR contributed an additional $7.4 million to HKMS for an additional 7,421,673 partnership units increasing KERR’s ownership interest to 46.24%. After the initial funding from KERR was consumed and additional funds were required to fund completion of the plant construction and further capital costs, KERR elected not to make additional contributions and Harvest has provided such funding. The remaining 53.76% (34,946,327 partnership units) has been contributed by Harvest as cash was required for the completion of construction of the gas processing facility. As Harvest provides such funding, its partnership interest will be increased and KERR’s interest will be diluted proportionately. On the earlier of 10.5 years after the formation of HKMS or when KERR achieves a specified internal rate of return, Harvest will have the right but not the obligation to purchase all of KERR’s interest in HK MS Partnership for nominal consideration. As at December 31, 2015, $73.6 million (2014 -$26.7 million) of contribution has been made by Harvest to the HKMS partnership and represents a 69.93% ownership interest. Harvest’s ownership of HKMS by quarter was the following:

	As at December 31,	
	2015	2014
Harvest's ownership interest	**69.93%**	47.01%
KERR's ownership interest	**30.07%**	52.99%
Total	**100%**	100%

Below is an overview of operational and financial highlights of these investments for the year ended December 31, 2015. Unless otherwise noted the following discussion relates to 100% of the joint venture results and not based on Harvest ownership share.

	Year Ended December 31	
	2015	2014
Revenues	**19.8**	**-**
Operating expenses and Other	**(1.5)**	**-**
Depreciation and amortization	**(3.1)**	**-**
Finance costs	**(15.0)**	**-**
Net loss(1)	**0.2**	**-**

(1) Balances represent 100% share of HKMS.

The Gas Processing Agreement between the HKMS and DBP ensures that HKMS receives an 18% internal rate of return on capital deployed over the term of the contract. In order to guarantee this return, DBP is required to provide HKMS with a minimum monthly capital fee that is currently $1.9 million a month. This capital fee is accounted for as revenue for HKMS and an operating expense for the DBP. In addition HKMS also generates revenue from charging an operating fee to recover operating expenses incurred. For the year ended December 31, 2015 the partnership generated revenues of $19.8 million (2014 – $nil).

As discussed above, operating expenses of the facility are recovered through charging an operating fee to the producers. For the year ended December 31, 2015 the partnership operating expense was $1.5 million (2014 – $nil).

Depreciation has been calculated on a straight-line basis over a 30 year useful life. Based on the capital expenditures incurred to date, the depreciation on a monthly basis is approximately $0.3 million per month. For the year ended December 31, 2015 the partnership depreciation expense was $3.1 million (2014 – $nil).

Finance costs mainly represent an accounting charge resulting from the Partner's contributions being classified as liabilities, as a result of the Gas Processing Agreement guaranteed returns. The finance costs represent the 18% rate of return on the partner's contributions. For the year ended December 31, 2015 the partnership finance costs was $15.0 million (2014 – $nil).

See note 12 of the December 31, 2015 audited consolidated financial statements under Item 18 of this annual report for discussion of the accounting implications of these joint arrangements.

BLACKGOLD OILSANDS

Operating Results

	Year Ended December 31, 2015
Expenses	
Pre-operating	**14.1**
General and administrative	**3.1**
Depreciation and amortization	**0.5**
Impairment of property, plant and equipment	**491.0**
Operating loss(1)	**(508.7)**

(1) This is an additional GAAP measure; please refer to "Additional GAAP Measures".

As the CPF was substantially completed during the first quarter of 2015, the operating expenses that were previously capitalized to property plant and equipment are now expensed on the income statement. For the year ended December 31, 2015 Harvest recognized an operating loss of $508.7 million (2014 – $nil, 2013 – $nil), mainly due to an impairment expenses of $491.0 million combined with labour, power, maintenance and general and administrative expenses.

During the year ended December 31, 2015, the BlackGold segment recognized impairment expense of $491.0 million against its PP&E respectively (2014 – $nil, 2013 – $nil). The impairment was triggered primarily by a decline in oil prices and delay in the first steam. The recoverable amount was estimated using the assets' value in use ("VIU"), estimated using the net present value of proved, probable and possible reserves discounted at a pre-tax rate of 12% (11% in the third quarter) for proved plus probable reserves and 15% for possible reserves. Please refer to note 9 of the December 31, 2015 consolidated financial statements under Item 18 of this annual report for further discussion.

The impairments discussed above may be reversed, if and when the fair values of the CGU increase in future periods. Any asset impairment that is reversed is recoverable to its original value less any associated DD&A expense. The results of the impairment tests conducted during the year ended December 31, 2015 are sensitive to changes in any of the key management judgments and estimates inherent in the calculations. These judgments and estimates include revisions in reserves or resources, a change in forecast commodity prices, expected royalty rates, required future development expenditures, and expected future production costs all of which could increase or decrease the recoverable amount of the assets.

Capital Asset Additions

	Year Ended December 31		
($ millions)	**2015**	2014	2013
Well equipment, pipelines and facilities	**44.4**	198.8	404.0
Pre-operating costs	**6.8**	32.2	0.6
Drilling and completion	**0.4**	6.3	13.7
Capitalized borrowing costs and other	**14.4**	46.2	26.2
Total BlackGold additions	**66.0**	283.5	444.5

During 2015, Harvest focused on the construction of the CPF and spent $44.4 million (2014 - $198.8 million, 2013 - $404.0 million) on the related well equipment, pipelines and facilities. Capital additions have decreased from the year ended December 31, 2013 through to 2015 as work has been performed at a measured pace due to liquidity and the economic environment.

Oil Sands Project Development

Harvest has been developing its BlackGold oil sands CPF under the engineering, procurement and construction (“EPC”) contract. Initial drilling of 30 steam assisted gravity drainage (“SAGD”) wells (15 well pairs) was completed by the end of 2012 and the majority of the well completion activities were completed by the end of 2014. 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. During the first quarter of 2015 construction had been substantially completed, including the building of the CPF plant site, well pads, and connecting pipelines. Several systems have since been commissioned and others will be performed at a measured pace due to liquidity and the economic environment. The decision to complete commissioning of the CPF and commence steam injection depends on a number of factors including the bitumen price environment.

Harvest has recorded $1,080.4 million of costs on the entire project since acquiring the BlackGold assets in 2010. This $1,080.4 million includes certain Phase 2 pre-investment which is expected to improve the capital efficiency over the project lifecycle. Under the EPC contract, $94.9 million of the EPC costs will be paid in equal installments, without interest, over 10 years. Payments commenced during the second quarter of 2015 with two payments made on April 30, 2015. 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, 2015, Harvest recognized a liability of $62.0 million (2014 - $77.8 million, 2013 - $76.2 million) using a discount rate of 5.5% (2014 - 4.5%, 2013 – 4.5%).

As Harvest uses the unit of production method for depletion and the BlackGold assets currently have no production, no depletion on the BlackGold property, plant and equipment has been recorded. Minor depreciation has been recorded during the twelve months ended December 31, 2015 on administrative assets.

The BlackGold project faces similar cost and schedule pressures as other oil sand projects. 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, 2015 were $50.1 million (2014 - $47.5 million, 2013 - $34.3 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.

<u>DISCONTINUED OPERATIONS</u>

<u>DOWNSTREAM</u>

The Downstream financial and operating results discussed below and elsewhere in the annual report for the year 2014 represents the period from January 1, 2014 to November 13, 2014, as the Downstream segment was disposed of on November 13, 2014.

Harvest recorded an additional loss of $15.5 million related to the disposal of the Downstream segment during the year ended December 31, 2015, which has been included in the net loss from discontinued operations (2014 - $56.6 million). The loss recorded in 2015 primarily relates to certain post-closing working capital adjustments.

Summary of Financial and Operational Results

(in $ millions except where noted)	2014	2013
FINANCIAL		
Refined products sales(1)	3,432.1	4,416.9
Purchased products for processing and resale(1)	3,250.0	4,327.4
Gross margin(2)	182.1	89.5
Expenses		
Operating	107.4	126.4
Power and purchased energy	102.4	106.7
Marketing	6.0	5.4
General and administrative	0.5	0.6
Depreciation and amortization	12.8	82.8
Gain on dispositions of PP&E	(0.2)	(0.2)
Impairment of property, plant and equipment	179.3	458.9
Operating loss(2)	(226.1)	(691.1)
Capital asset additions	27.8	53.2
OPERATING		
Feedstock volume (bbl/d)(3)	86,520	98,081
Yield (% of throughput volume)(4)		
Gasoline and related products	32%	31%
Ultra low sulphur diesel and jet fuel	37%	37%
High sulphur fuel oil	28%	29%
Total	97%	97%
Average refining gross margin (US$/bbl)(5)	4.43	1.07

(1) Refined product sales and purchased products for processing and resale are net of intra-segment sales of $491.1 million in 2014 and $555.4 million in 2013, 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) Barrels per day are calculated using total barrels of crude oil feedstock and vacuum gas oil.
(4) Based on production volumes after adjusting for changes in inventory held for resale.
(5) Average refining gross margin is calculated based on per barrel of feedstock throughput.

Refining Benchmark Prices

	Year Ended December 31	
	2014	2013
WTI crude oil (US$/bbl)	93.00	97.97
Brent crude oil (US$/bbl)	99.48	108.75
Argus sour crude index ("ASCI") (US$/bbl)	92.37	102.02
Brent – WTI differential (US$/bbl)	6.48	10.78
Brent – ASCI differential (US$/bbl)	7.11	6.73
Refined product prices		
RBOB (US$/bbl)	110.70	119.11
Heating Oil (US$/bbl)	117.15	125.76
High Sulphur Fuel Oil (US$/bbl)	84.04	93.15
U.S. / Canadian dollar exchange rate	0.905	0.971

Summary of Gross Margin

	Year Ended December 31					
	2014			2013		
		Volumes			Volumes	
(in $ millions except where noted)		(million bbls)	(US$/bbl)		(million bbls)	(US$/bbl)
Refinery						
Sales						
Gasoline products	1,111.7	9.1	110.69	1,446.00	12.3	113.83
Distillates	1,442.8	11.0	119.08	1,833.20	14.5	122.76
High sulphur fuel oil	633.5	6.8	84.32	759.3	8.3	89.28
Other(1)	126.2	1.1	100.91	249.4	2.2	109.39
Total sales	3,314.2	28.0	107.18	4,287.90	37.3	111.6
Feedstock (2)						
Crude oil	2,885.8	27.0	96.90	3,645.80	33.4	105.9
Vacuum Gas Oil ("VGO")	55.1	0.5	105.05	270.5	2.4	110.81
Total feedstock	2,940.9	27.5	97.04	3,916.30	35.8	106.22
Other(3)	239.0			332.1		
Total feedstock and other costs	3,179.9			4,248.40		
Refinery gross margin(4)	134.3		4.43	39.5		1.07
Marketing						
Sales	609.0			684.4		
Cost of products sold	561.2			634.4		
Marketing gross margin(4)	47.8			50.0		
Total gross margin(4)	182.1			89.5		

(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

2014-2013

The average throughput rate for the year ended December 31, 2014 was 86,520 bbl/d, a 12% decrease from the 98,081 bbl/d in the prior year. The lower daily average throughput rate for 2014 is a consequence of a power outage in January, an unplanned outage in the last week of March, a planned three week outage on the platformer unit for regular maintenance followed by an unplanned ten day outage on the isomax unit.

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					
	2014			2013		
	Refinery	Benchmark(1)	Difference	Refinery	Benchmark(1)	Difference
Gasoline products (US$/bbl)	13.65	11.22 (2)	2.43	7.6	10.36 (2)	(2.76)
Distillates (US$/bbl)	22.04	17.67 (2)	4.37	16.54	17.01 (2)	(0.47)
High Sulphur Fuel Oil (US$/bbl)	(12.72)	(15.44)(3)	2.72	(17.76)	(15.60)(3)	(2.16)

(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. Downstream's crack spreads for gasoline products and distillates in the above tables include the actual cost of renewable identification numbers ("RIN") 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. Our average RINs cost for the 2014 year to date was approximately US$2.00/bbl (2013 - US$2.50/bbl) for RBOB gasoline and US$2.10/bbl (2013 - US$3.00/bbl) for ULSD products.

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

<u>2014-2013</u>

The refinery gross margin for the year ended December 31, 2014 was significantly higher than the $39.5 million as reported in the prior year due to higher realized product margins.

Our crude feedstock differential for the year ended December 31, 2014 is slightly lower than the differentials in 2013. Our realized sour crude differential of US$2.58/bbl for the year ended December 31, 2014 is US$0.27/bbl lower than our sour crude differential of US$2.85/bbl in the prior year. The narrowing realized differential is the result of processing more higher priced light sweet crudes which comprised 26% of our feedstock crude slate this year as compared to 21% in 2013. The improved yields normally associated with processing light sweet crudes (higher yield of the high value light end products and a lower yield of the low value heavy products) have been offset by outages on the refinery units in both years.

Operating Expenses

	Year Ended December 31					
	2014			2013		
($ millions)	Refining	Marketing	Total	Refining	Marketing	Total
Operating cost	88.5	18.9	107.4	104.8	21.6	126.4
Power and purchased energy	102.4	–	102.4	106.7	–	106.7
	190.9	18.9	209.8	211.5	21.6	233.1
($/bbl of feedstock throughput)						
Operating cost	3.23	–	–	2.92	–	–
Power and purchased energy	3.73	–	–	2.98	–	–
	6.96	–	–	5.90	–	–

The refining operating cost per barrel of feedstock throughput increased by 11% for the year ended December 31, 2014 as compared to 2013 mainly as a result of decreased throughput in 2014. Purchased energy, consisting of LSFO and electricity, is required to provide heat and power to refinery operations. The purchased energy cost per barrel of feedstock throughput increased by 25% respectively during the year ended December 31, 2014 from 2013.

Capital Asset Additions

Capital asset additions for the year ended December 31, 2014 totaled $27.8 million (2013 - $53.2 million), which related to various capital projects. The capital additions were lowest in 2014 due to the minimal capital spending prior to the sale of the Downstream segment.

Depreciation and Amortization Expense

	Year Ended December 31	
($ millions)	2014	2013
Refining	10.3	79
Marketing	2.5	3.8
Total depreciation and amortization	12.8	82.8

Depreciation and amortization expense decreased $70.0 million for the year ended December 31, 2014 as compared to 2013. The decrease was primarily due to the $458.9 million impairments of refinery property, plant and equipment which occurred in the fourth quarter of 2013. The process units were amortized over an average useful life of 20 to 35 years and turnaround costs are amortized to the next scheduled turnaround.

Currency Exchange

As Downstream operations' functional currency is denominated in U.S. dollars, the strengthening (weakening) of the U.S. dollar resulted in unrealized currency exchange gains (losses) from its decommissioning liabilities, pension obligations, accounts payable and other balances that are denominated in Canadian dollars. The U.S. dollar also strengthened at December 31, 2014 as compared to December 31, 2013 resulting in an unrealized foreign exchange gain of $21.6 million (2013 - $34.3 million).

The cumulative translation adjustment 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, 2014, Downstream incurred a net cumulative translation loss of $9.9 million (2013 - gain of $7.9 million), reflecting the changes in the Canadian dollar relative to the U.S. dollar on Harvest's net investment in the Downstream segment at December 31, 2014 compared to December 31, 2013.

Disposition of the Downstream Segment and Impairment on PP&E and other

Downstream operations included 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 was located in the Province of Newfoundland and Labrador. On November 13, 2014, Harvest closed the sale of the Downstream segment for net proceeds of approximately $70.5 million subject to post-closing adjustments. The Downstream segment has been classified as discontinued operations as at December 31, 2014.

The purchase and sale agreement to sell the Downstream segment triggered an impairment and onerous contract assessment during the third quarter of 2014. As a result of this assessment an onerous contract provision was recorded in the third quarter of 2014. Downstream recorded a $179.3 million impairment loss for the year ended December 31, 2014 (2013 - $458.9 million) of the Downstream segment relating to the PP&E to reflect a recoverable amount of $nil at December 31, 2014. This amount has been included in the operating loss from discontinued operations. Also see note 8, Discontinued Operations of the December 31, 2015 audited consolidated financial statements under Item 18 of this annual report.

Upon the disposal of the Downstream segment, a $44.1 million cumulative foreign translation adjustment loss was reclassified from accumulated other comprehensive income to the loss on disposal of the Downstream segment. Harvest recognized a loss on disposal of the Downstream segment of $56.6 million during the fourth quarter and year ended December 31, 2014.

As it was no longer probable for Downstream to utilize the deferred tax assets of $92.1 million, it was written down to $nil during the third quarter of 2014. Harvest also completed a strategic tax planning transaction during the third quarter of 2014, which resulted in an increase of deferred tax assets in the amount of $247.6 million. See note 18, Income Taxes of the December 31, 2014 audited consolidated financial statements under Item 18 of this annual report.

CORPORATE

Cash Flow Risk Management

The Corporation 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, 2014. There were no risk management contracts outstanding at December 31, 2015.

2014

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

Contract Quantity	Type of Contract	Term	Contract Price	Fair Value
5,400 GJs/day	AECO swap	Jan – Dec 2015	$3.65/GJ	$1.9

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 2015	$47.75/MWh	($1.2)

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

	Year Ended December 31															
($ millions)	**2015**						2014					2013				
Realized (gains) recognized in:	**Power**	**Crude Oil**	**Currency**	**Natural Gas**	**Top-up Obligation**	**Total**	Power	Crude Oil	Currency	Natural Gas	Total	Power	Crude Oil	Currency	Natural Gas	Total
Revenues	**—**	**(12.5)**	**—**	**(4.5)**	**—**	**(17.0)**	—	(10.7)	—	7.7	(3.0)	—	3.3	—	(7.2)	(3.9)
Derivative (gains) losses	**4.2**	**—**	**0.2**	**—**	**—**	**4.4**	1.6	—	(0.2)	—	1.4	(3.1)	(0.4)	(1.4)	—	(4.9)
Unrealized (gains) recognized in:					**—**											
OCI, before tax	**—**	**(12.5)**	**—**	**(2.6)**	**—**	**(15.1)**	—	(10.6)	—	5.9	(4.7)	—	3.3	—	(5.7)	(2.4)
Derivative (gains) losses	**(1.2)**	**—**	**—**	**—**	**2.0**	**0.8**	0.7	—	—	—	0.7	0.5	—	—	—	0.5

Financing Costs

	Year Ended December 31		
($ millions)	**2015**	2014	2013
Credit facility	**24.5**	25.0	20.3
Convertible debentures	**—**	—	14.9
6⅞% senior notes	**46.9**	40.3	37.4
2⅛% senior notes(1)	**22.8**	19.6	11.7
Related party loans	**30.5**	20.2	8.1
Amortization of deferred finance charges and other	**2.0**	1.6	1.4
Interest and other financing charges(2)	**126.7**	106.7	93.8
Accretion of decommission and environmental remediation liabilities	**—**	22.0	21.8
Gain on redemption of convertible debentures	**—**	—	(3.6)
Less: capitalized interest	**—**	(33.4)	(19.8)
Total finance costs(2)	**126.7**	95.3	92.2

(1) Includes guarantee fee to KNOC.

(2) Excludes discontinued operations of the Downstream segment.

The finance costs on the credit facility have declined from the year ended December 31, 2015 to 2014, mainly due to lower effective interest rate, partially offset by the impact of a greater amount of drawn amounts during 2015. Interest expense on

Harvest's credit facility increased in 2014 due to the higher average amount of loan principal outstanding as compared to 2013. See note 13 and 21 of the December 31, 2015 audited consolidated financial statements under Item 18 of this annual report.

The finance costs on the 2⅛% senior notes and 6⅞% senior notes have increased from 2013 to 2015 due to changes in foreign exchange as the notes are U.S. dollar denominated.

The finance costs on related party loans has increased from 2013 to 2015 due to the additional borrowings in made and because of the weakening Canadian dollar from 2013 to 2015. See discussion in the "Related Party Transaction" section of this annual report.

Capitalized interest relates to amounts borrowed to fund the capital expenditures of BlackGold. The decrease in capitalized interest for the year ended December 31, 2015 is due to the BlackGold Central processing facility being substantially completed in the first quarter of 2015 and all direct and indirect borrowing cost during the remainder of 2015 were expensed. During the year ended December 31, 2014, interest expense of $33.4 million was capitalized to BlackGold. In 2013, $19.8 million was capitalized to BlackGold. The increase in capitalized interest for the year ended December 31, 2014 from 2013 is mainly due to the increase in our long-term borrowings attributable to BlackGold.

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

	Year Ended December 31		
($ millions)	**2015**	2014	2013
Realized losses on foreign exchange[(1)]	**2.1**	1.5	3.5
Unrealized losses on foreign exchange[(1)]	**308.4**	124.9	75.2
	310.5	126.4	78.7

(1) Excludes discontinued operations of the Downstream segment.

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 6⅞% and 2⅛% senior notes, the ANKOR and KNOC related party loans and on any U.S. dollar denominated monetary assets or liabilities. At December 31, 2015, the Canadian dollar had weakened as compared to the US dollar as at December 31 2014 resulting in an unrealized foreign exchange loss of $308.4 million (2014 – $124.9 million loss, 2013 – $75.2 million loss). Harvest recognized a realized foreign exchange loss of $2.1 million for the year ended December 31, 2015 (2014 – $1.5 million loss, 2013 – $3.5 million loss) as a result of the settlement of U.S. dollar denominated transactions.

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 ended December 31, 2015 Harvest recorded a current income tax expense of $5.1 million (2014 - $nil, 2013 - $nil). The current income tax expense relates to an assessment from a prior period Canada Revenue Agency audit adjustment.

For the year ended December 31, 2015 Harvest recorded deferred income tax recoveries from its Upstream operations of $336.9 million (2014 – $324.9 million, 2013 – $39.4 million). The current year deferred income tax recovery relates primarily to impairment charges taken during the year reducing the book basis of Harvests assets relative to their tax basis as well as the Alberta corporate tax rate increasing from 10 per cent to 12 per cent effective July 1, 2015. The prior year recovery is mainly due to the recognition of $247.6 million previously unrecognized deferred tax assets in the Downstream Segment. See the "Disposition of the Downstream Segment and Impairment Loss" section of this annual report for further discussion.

Harvest's deferred income tax asset will fluctuate during each accounting period to reflect changes in the temporary differences between the book value and tax basis of assets and liabilities. Currently, the principal sources of temporary differences relate to the Company's property, plant and equipment, decommissioning liabilities and the unclaimed tax pools. For further discussion, see note 19 of the audited consolidated financial statements for the year ended December 31, 2015 under Item 18 of this annual report.

B. Liquidity and Capital Resources

LIQUIDITY

Cash Flow Analysis

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

Cash flows for continuing and discontinued operations are presented on a combined basis in the consolidated financial statements. Cash flow used in operating activities for the year ended December, 2015 was $35.4 million (2014 – cash flows from operating activities $482.9 million, 2013 – $200.6 million cash flows from operating activities). The decrease for the year ended December 31, 2015 is mainly a result of the decreased revenue and working capital partly offset by decrease in operating and G&A expenses when compared to the prior year. The increase from 2013 to 2014 is mainly a result of the decrease in cash deficiency from discontinued operations and the increase in the change in non-cash working capital.

Cash contribution from Harvest's Upstream operations for the year ended December 31, 2015 was $154.3 million (2014 – $485.4 million, 2013 – $581.9 million). The decrease in Upstream's cash contribution for 2015 as compared to 2014 is mainly due to the decrease in average realized prices and lower sales volumes, partially offset by lower expenses. The decrease from 2013 to 2014 was mainly due to lower sales volumes, partially offset by higher realized prices than 2013.

Harvest funded capital expenditures for the year ended December 31, 2015 of $265.8 million (2014 – $718.2 million, 2013 – $758.1 million, including the Hunt acquisition) property dispositions and borrowings under both the credit facility and the US$171 million KNOC subordinated loan.

Harvest's net drawings from the credit facility was $304.4 million during the year ended December 31, 2015 (2014 – $169.4 million net repayment, 2013 – $293.8 million net drawing).

Liquidity Analysis

Harvest had a working capital deficiency of $1,070.5 million as at December 31, 2015, as compared to a $300.5 million deficiency at December 31, 2014, mainly due to the classification of the credit facility as current due to the covenant violation at year end. As a result of obtaining a covenant waiver subsequent to year end, the credit facility will be reclassified as long term in the first quarter to 2016. After adjusting for the current classification of credit facility, the adjusted net working capital deficiency as at December 31, 2015 was $146.7 million. As at December 31, 2015, we had $76.2 million undrawn under our credit facility and in our view the working capital is net sufficient to meet the Company's present short term needs. 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, managing the collection and payment of account receivables and account payables respectively and using the proceeds from possible sale of assets, as required.

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 that were externally imposed under the Company's credit facility and the senior notes. 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.

As noted above, the current year negative cash flow from operations was primarily due to low commodity price environment. In response to the low commodity price environment, Harvest plans to constrain its capital expenditures in 2016, focusing on capital maintenance and regulatory activities. Harvest also continues to postpone first steam for the BlackGold project in response to the unfavourable heavy oil prices and will continually assess the commodity price environment to determine when to complete commissioning of the CPF and first steam injection. Furthermore, we plan to sell assets if necessary to meet our operating and capital requirements.

Harvest is a significant subsidiary for KNOC in terms of production and reserves. KNOC has directly or indirectly invested and provided financial support to Harvest since 2009 and as at the date of preparation of this annual report, it is the Company's expectation that such support will continue for at least next twelve months so that Harvest is able to continue as a going concern. In addition, Harvest plans to refinance its long term debt(s) as they become due. 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, 2015 and 2014:

(in $ millions except where noted)	**December 31, 2015**	December 31, 2014
Credit facility(1)	**926.6**	620.7
6⅞% senior notes (US$500 million)(1)(2)	**692.0**	580.1
2⅛% senior notes (US$630 million)(1)(2)	**871.9**	730.9
Related party loans (US$290 million and CAD$200 million)(2)(3)	**601.4**	397.2
	3,091.9	2,328.9
Shareholder's equity (deficit)		
386,078,649 common shares issued	**(275.3)**	1,534.8
	2,816.6	3,863.7
Financial Ratios(4) (5)		
Senior debt to annualized EBITDA	**—**	1.37
Annualized EBITDA to annualized interest expense	**—**	4.30
Senior debt to total capitalization	**—**	16%
Total debt to total capitalization	**79%**	49%

(1) Excludes capitalized financing fees
(2) Face value converted at the period end exchange rate
(3) As at December 31, 2014, related party loans comprised of US$170 million from ANKOR and CAD$200 million from KNOC (see note 25 of the December 31, 2015 audited financial statements under Item 18 of this annual report)
(4) Calculated based on Harvest's credit facility covenant requirements (see note 13 of the December 31, 2015 annual consolidated financial statements under Item 18).
(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, 2015, 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 allocated among any one or more party of (1), (2) and (3) below :

1. 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;
2. Contribution basis: to the extent of proceeds received by Harvest after March 15, 2015 from the issuance of equity or intercompany subordinated debt; and
3. Stipulated amount basis: on the basis of an aggregate amount of Distributions not to exceed $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.

Credit Facility

On April 22, 2015, Harvest amended its $1 billion syndicated revolving credit facility and replaced it with a $940 million revolving credit facility that matures on April 30, 2017, with a syndicate of eight financial institutions. On July 15, 2015 Harvest secured a $60 million commitment from a new lender to increase the borrowing capacity of the new facility to $1 billion. The facility is secured by KNOC's guarantee (up to $1.0 billion) and by a first floating charge over all of the assets of Harvest and its material subsidiaries. A guarantee fee of 0.37% per annum of the principal balance is payable to KNOC semi-annually.

Under the amended credit facility, applicable interest and fees will be based on a margin pricing grid based on the credit ratings of KNOC. The financial covenants under the previous credit facility were deleted and replaced with a new covenant: Total Debt to Capitalization ratio of 70% or less. At December 31, 2015, Harvest was in violation of the debt covenant and the carrying value of the credit facility, $923.8 million, was reclassified from long-term debt to a current liability.

At December 31, 2015, Harvest had $73.4 million (2014 - $379.3 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.

Subsequent to December 31, 2015, Harvest's syndicate banks consented to a waiver of this covenant for the duration of the term of the credit facility. Please see Item 10C "Material Contracts" for further details.

6⅞% Senior Notes

Harvest had $692.0 million (2014 - $580.1 million) of principal amount of US$500 million its 6⅞% Senior Notes outstanding at December 31, 2015. The 6⅞% Senior Notes are unsecured with interest payable semi-annually on April 1 and October 1 and mature on October 1, 2017. The 6⅞% 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 6⅞% Senior Notes are redeemable at a redemption price equal to the greater of 100% of the principal amount of the 6⅞% 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, 2015. At December 31, 2015, Harvest was in compliance with all covenants under the senior notes.

2⅛% Senior Notes

Harvest had $871.9 million (2014 - $730.9 million) of principal amount of US$630 million its 2⅛% Senior Notes outstanding at December 31, 2015. Interest on the 2⅛% senior notes is paid semi-annually on May 14 and November 14 of each year and are due on May 14, 2018. The 2⅛% 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 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, 2015, Harvest has drawn the full $200 million available under the loan agreement.

On April 2, 2015, Harvest entered into a US$171 million loan agreement with KNOC, repayable within one year from the date of the first drawing, which was on April 10, 2015. The interest rate on drawn loan was 3.42% per annum. As at December 31, 2015, the carrying value of this loan was $170.2 million including $166.1 million (US$120 million) principal and $4.1 million interest accrual. Interest expense was $3.8 million for the year ended December 31, 2015. On December 31, 2015 KNOC approved an extension in the maturity of the loan to December 31, 2017 and the interest rate was increased to 5.91% per annum.

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.

Please see "Liquidity Analysis" section above for subsequent events relating to Harvest's capital resources. For Harvest's treasury policies, see Item 11 "Quantitative and Qualitative Disclosures about Market Risks".

C. Research and Development

Not applicable.

D. Trend Information

Production from our oil and gas properties is the primary determinant for the volume of sales during the year. There are a number of trends that have been developing in the oil and gas industry during the past several years that appear to be shaping the near future of the business.

The first trend is the volatility of commodity prices. Prices for crude oil and natural gas have continued to be volatile since the end of 2014. The surplus supply in the world oil market has led to a steady drop in price since mid-2014. The surplus continues, and producers, especially in North America have substantially reduced exploration and drilling programs. The surplus is exacerbated by certain oil producing nations who are reluctant to reduce market share in respect to lower prices. North America accelerated the construction of infrastructure (pipelines and rail networks) to move rising supply from the centre of the continent to the southwest of Texas to refineries located on the American coast of the Gulf of Mexico and the east coast of the United States, displacing crude oil imports into refineries along the U.S. Gulf coast and the U.S. is now exporting crude oil, which is reducing the Brent to WTI differential.

Natural gas is a commodity influenced by factors within North America. A tight supply demand balance for natural gas causes significant volatility in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Natural gas production has continued near record levels in spite of a reduction in drilling activity. Natural gas storage levels, which in 2014 were in deficit position as measured on a year-over-year basis, are now in a year-over-year surplus. Changes to any of these or other factors create price volatility. Crude oil is also influenced by the world economy, Organization of the Petroleum Exporting Countries' ("OPEC") ability to adjust supply to world demand and weather. Political events also trigger large fluctuations in price levels. Petroleum prices are expected to remain volatile for at least the near term as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and ongoing geopolitical concerns.

The impact on the oil and gas industry from commodity price volatility is significant. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. As prices continue to hover near multi-year lows, cash flows across the industry are severely challenged. Companies are responding by dramatically cutting costs and deferring capital spending. However, bankruptcies are on the rise and could escalate if low prices persist. With decreased demand, the prices charged by the various service suppliers also decline. World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. Material increases in the value of the Canadian dollar may negatively impact production revenues from Canadian producers. Such increases may also negatively impact the future value of such entities' reserves as determined by independent evaluators. Harvest continues to work with third party 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.

A second trend within the Canadian oil and gas industry is the "renewal" of private oil and gas companies looking to take advantage of low prices to buy oil and gas assets at distressed prices. These companies often have experienced management teams from previous industry organizations that have disappeared as a part of the ongoing industry consolidation. Many are able to raise capital and recruit well qualified personnel. To the extent that this trend continues, we will have to compete with these companies and others for assets and to attract qualified personnel.

A third trend is the continued growth in the development of shale crude oil and natural gas formations using long reach horizontal wells with multiple staged simulated fractures. These shale developments generally involve the drilling of very deep wells with very long horizontal "legs" from well pads which allow for multiple wells to be drilled from one location. These developments are very expensive compared to shallow, vertical well developments that were historically used in the industry. If pricing for both crude oil and natural gas continues to be "soft" throughout 2016 and into 2017, it will be very challenging for smaller oil and gas companies to access debt or equity capital to fund development of these very expensive plays. This could lead to the consolidation of smaller oil and gas companies, acquisitions by larger oil and gas companies, or an increase in outright bankruptcies of smaller oil and gas companies.

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. Past performance should not be relied on as an indicator of future performance. Please refer to Item 3D "Risk Factors" for the risks associated with Harvest.

E. Off-Balance Sheet Arrangements

See "Investments in Joint Arrangements" section in this annual report and note 12, "Investment in Joint Ventures" in the December 31, 2015 audited consolidated financial statements under Item 18.

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, 2015, Harvest has the following significant contractual commitments:

	Payments Due by Period				
	1 year	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Debt repayments(1)	—	3,089.0	—	—	3,089.0
Debt interest payments(1) (2)	81.9	191.1	—	—	273.0
Purchase commitments(3)	12.5	21.0	19.0	47.9	100.4
Operating leases	8.2	15.6	14.5	34.7	73.0
Firm processing commitments	19.8	35.6	29.0	70.3	154.7
Firm transportation agreements	18.5	59.9	43.8	59.6	181.8
Employee benefits(4)	4.9	4.8	—	—	9.7
Decommissioning and environmental liabilities(5)	42.2	93.2	44.3	1,258.9	1,438.6
Total	188.0	3,510.2	150.6	1,471.4	5,320.2

(1) Assumes constant foreign exchange rate.
(2) Assumes interest rates as at December 31, 2015 will be applicable to future interest payments.
(3) Relates to drilling and BlackGold oil sands project commitment.
(4) Relates to the long-term incentive plan payments.
(5) 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, 2015 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, profit & loss 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.
Cheol Woong Choi(7) Seoul, South Korea	Director since November 2014	Mr. Choi joined KNOC in 2003 and is currently Senior Manager, Accounting Team for KNOC. Prior thereto, he was Finance Director, KNOC Kazakhstan Group from 2008 to 2012.
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. 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. 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 2011 and PGNX Capital Corp. from 2008 to 2014.
Dae-Jung Hong Seoul, South Korea	Director since April 2016	Mr. Hong was appointed Director of Harvest in April 2016 and is currently Vice President of Finance Management at KNOC. Mr. Hong has a Bachelor of Business Administration from Dong-A University.
Chang-Seok Jeong(1) Seoul, South Korea	Former Director and Chairman of the Board	Mr. Jeong has been Executive Vice President of Production Group at KNOC since January 2012 and Chairman of Dana Petroleum Plc. since 2013. 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 at KNOC. Mr. Jeong joined KNOC in 1986. Mr. Jeong was a Harvest's director since January 2012 and was appointed Chairman of the Board in August 2013. Effective April 15, 2016, Mr. Jeong resigned as Director and Chairman of the Board.

Name and Jurisdiction of Residence	Position with Harvest Operations	Principal Occupation(s) and Other Relevant Experiences
Richard Kines Alberta, Canada	Director since May 2013	Mr. Kines currently consults in senior financial executive roles. He has over 36 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.
Seungkook Lee Seoul, South Korea	Director since April 2016	Mr. Lee was appointed Chairman of Harvest in April 2016 and is currently Executive Vice President of the E&P Group at KNOC. Mr. Lee obtained both a Bachelor and Master of Petroleum Engineering from Hanyang University.
Kyungluck Sohn (2) Alberta, Canada	Former President & CEO and Director	Mr. Sohn was appointed President and Chief Executive Officer of Harvest Operations Corp. in July 2014. Mr. Sohn was the Vice President, Finance Management Department at KNOC and was the Chief Financial Officer of Harvest from February 16, 2010 to January 13, 2012. Prior thereto, Mr. Sohn served as a Vice President of KNOC's Finance Management department in 2009. Mr. Sohn was President and Chief Executive Officer, and Director of Harvest from July 2014 to February 2016.
Piljong Sung (3) Alberta, Canada	Interim President & Chief Executive Officer since February 2016, appointed Director of the Corporation effective April 2016 and Chief Strategy Officer & Corporate Secretary since August 2013	Mr. Sung was appointed Interim President and Chief Executive Officer in February 2016 and concurrently is Chief Strategy Officer & Corporate Secretary of Harvest. Prior thereto, he was a Senior Manager of Exploration & Production Auditing Team from 2007 to 2013 at KNOC. Effective April 2016, Mr. Sung was appointed Director of the Corporation.
John Wearing (4) Alberta, Canada	Former Chief Operating Officer	Mr. Wearing was appointed Chief Operating Officer of Harvest in April 2014. Mr. Wearing has been with Harvest since 2011. Prior thereto, he most recently held the position of Director, Corporate Partnerships. Mr. Wearing has over 30 years of experience in the oil and gas industry and prior to joining Harvest was Acting CEO of Sulfur Recovery Engineering Inc. and the VP, Operations at CTI Resources among other management level engineering roles. Mr. Wearing was Chief Operating Officer of Harvest from April 2014 to February 2016.
Sungki Lee Alberta, Canada	Director and Chief Financial Officer since July 2014	Mr. Lee is currently the Chief Financial Officer and Director of Harvest. He has worked for KNOC since 1993 and has held positions including Senior Manager, Asset Optimization Department, Senior Manager, Business Development Department, Manager, E&P Planning Department, and Manager, Vietnam Office.

Name and Jurisdiction of Residence	Position with Harvest Operations	Principal Occupation(s) and Other Relevant Experiences
Patrick BH An [(5)] Alberta, Canada	Former Vice President, BlackGold from 2011 to July 2014 and Deputy Chief Operating Officer from July 2014 to December 2015	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. Effective December 2015, Mr. An has been reassigned within KNOC.
Taeheon Jang [(6)] Alberta, Canada	Deputy Chief Operating Officer since October 2015 and Vice President, BlackGold since November 2015	Mr. Jang joined Harvest in February 2014. He has worked for KNOC for the past 19 years and has held positions including Vice President, Global Research & Technology Centre, Senior Manager, Petroleum Engineering Department, Project Manager, New Venture Team and Business Development Director, Caspian Branch Office. Mr. Jang was appointed Deputy Chief Operating Officer in October 2015 and Vice President, BlackGold in November 2015.
Jon Lowes Alberta, Canada	Vice President, Land since February 2015	Mr. Lowes has over 35 years of oil and gas experience. He joined Harvest in June 2010 and was appointed Vice President, Land in February 2015. Mr. Lowes has lease administration, contracts, surface, A & D, and area landman experience and most recently was area landman for Harvest's Deep Basin area.
Phillip Reist [(4)] Alberta, Canada	Former Vice President, Controller	Mr. Reist was Controller of Harvest Operations from February 2006 to March 2007 and Vice President, Controller from March 2007 to February 2016.
Grant Ukrainetz Alberta, Canada	Vice President, Treasurer from February 2013 to February 2016 and Vice President, Finance since March 2016	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. Mr. Ukrainetz was Vice President, Treasurer from February 2013 until appointed Vice President, Finance in March 2016.
Erik van Noort [(4)] Alberta, Canada	Former Vice President, Technical Services	Mr. van Noort joined Harvest as an Area Manager in 2009 and was appointed as VP Technical Services from February 2015 to February 2016. Prior to joining Harvest, Mr. van Noort held various positions in facilities engineering, project management and marketing at Imperial Oil.

Name and Jurisdiction of Residence	Position with Harvest Operations	Principal Occupation(s) and Other Relevant Experiences
Doug Walker Alberta, Canada	Vice President, Engineering from November 2012 to February 2015 and Vice President, Operations and Development in February 2015. Appointed Vice President, Exploitation in March 2016	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 was Vice President, Engineering of Harvest from November 2012 to February 2015 and appointed Vice President, Operations and Development in February 2015. Mr. Walker was appointed Vice President, Exploitation in March 2016. 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) Effective April 2016, Mr. Jeong resigned as Director and Chairman of the Board of Directors.
(2) Effective February 2016, Mr. Kyungluck Sohn resigned as President & CEO and Director.
(3) Effective February 2016, Mr. Piljong Sung was appointed Interim President & CEO and effective April 2016 appointed as a Director of the Corporation.
(4) Effective February 2016, these individuals were no longer with Harvest.
(5) Effective December 2015, Mr. Patrick An was reassigned within KNOC.
(6) Effective October 2015, Mr. Taeheon Jang was appointed Deputy COO and effective November 2015 was appointed Vice President, BlackGold.
(7) Effective April 2016, Mr. Choi resign as Director of the Corporation

As at December 31, 2015, none of the directors and executive officers of Harvest and their associates and affiliates, directly or indirectly, beneficially owned, controlled or directed any of the outstanding shares of Harvest. 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 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 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	Compensation and Corporate Governance Committee
Allan Buchignani	✓	Chair	
Randall Henderson	Chair		✓
Chang-Seok Jeong (2)			Chair
Richard Kines	✓	✓	
Kyungluck Sohn (1)		✓	
Cheol Woong Choi(3)			✓
Seungkook Lee			Chair
Piljong Sung		✓	
Dae-Jung Hong			✓

(1) Effective February 2016, Mr. Kyungluck Sohn resigned as President & CEO and Director of Harvest.
(2) Effective April 2016, Mr. Chang-Seok Jeong resigned as Chair of the Compensation and Corporate Governance Committee.
(3) Effective April 2016, Mr. Cheol Woong Choi resigned as a Director of the Corporation

B. Compensation

COMPENSATION COMMITTEE AND CORPORATE GOVERNANCE COMMITTEE

At December 31, 2015, the Compensation and Corporate Governance Committee was comprised of Chang-Seok Jeong, Cheol Woong Choi 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 the 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 Board changes to improve Harvest's ability to recruit, retain and motivate employees;
- establish the goals and objectives of the CEO and annually review the performance of the CEO relative to the corporate goals and objectives;
- annually review and approve the CEO's recommendations of the overall compensation and other conditions of employment of Harvest's officers and employees, satisfy itself that the overall compensation is in accordance with the business plans of Harvest and with generally accepted compensation levels with comparable companies. The CCGC may recommend approval to the Board based on the CCGC's discretion; and
- 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.

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 the "CEO and CFO Compensation" section herein. The incentive programs (short-term and long-term) are available to all permanent employees of Harvest, 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. 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.

Executive 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 other Harvest 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 1^{st}. 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 2015, Harvest assessed the following primary performance metrics as part of the corporate performance review: Upstream production, EBITDA, operating cost on a per boe basis, reserves through drilling, and Upstream safety (loss time injury frequency). 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.

CEO and CFO Compensation

Harvest's human resources include secondees assigned by KNOC, including the Chief Executive Officer and Chief Financial Officer. These individuals do not participate in Harvest's short and long-term incentive plans nor do they receive salaries based on Harvest's salary structure. Pursuant to an agreement with KNOC, Harvest will compensate these employees with base salaries, annual bonus and benefits. Base salary is differentiated based on an annual performance assessment performed by KNOC senior management. The annual bonus is determined in accordance with individual performance and KNOC corporate performance assessed by the Korean Government. Benefits are provided based on KNOC's Personnel Policy. Harvest complies with all withholding, remittance and reporting requirements in Canada, in respect of any remuneration paid to the seconded employees.

COMPENSATION SUMMARY

The following table sets forth for the year ended December 31, 2015 information concerning the compensation paid to Harvest's executive officers and senior management.

Name and Principal Position	Year	Non-Equity Incentive Plan Compensation ($)				
		Salary ($)	Annual Incentive Plans[1]	Long-term Incentive Plans	All Other Compensation[2]	Total Compensation ($)
Kyungluck Sohn	2015	130,669	2,967	Nil	276,483	410,119
Chief Executive Officer [3][4]	2014	46,537	Nil	Nil	128,841	175,378
	2013	Nil	Nil	Nil	Nil	Nil
Sungki Lee	2015	92,432	Nil	Nil	313,962[5]	406,394
Chief Financial Officer[3][5]	2014	31,117	Nil	Nil	109,520	140,637
	2013	Nil	Nil	Nil	Nil	Nil
John Wearing	2015	305,370	Nil	155,379	40,977	501,726
Chief Operating Officer	2014	256,667	145,000	65,064	41,814	508,545
	2013	Nil	Nil	Nil	Nil	Nil
Doug Walker	2015	246,241	Nil	86,847	31,445	364,533
VP, Exploitation	2014	233,500	62,580	77,292	37,433	400,805
	2013	216,000	56,000	68,676	36,632	377,308
Phil Reist	2015	239,731	Nil	91,875	31,335	362,941
VP, Controller	2014	246,330	61,583	107,333	36,594	451,840
	2013	232,366	59,750	104,309	35,232	431,657

(1) The annual incentive plan amounts were paid shortly after the end of the fiscal year.
(2) Includes benefits such as living, vehicle and housing allowances, the payment of income taxes, contributions to a savings plan and other benefits.
(3) During 2014 Messrs. Sohn and Lee were directors of Harvest, but did not receive compensation for their services as directors.
(4) Mr. Sohn received a perquisite relating to the payment of income taxes in the amount of $231,580 in 2015, which comprised 84% of the total perquisites earned by Mr. Sohn in the year.
(5) Mr. Lee received a perquisite relating to the payment of income taxes in the amount of $196,665 in 2015, which comprised 63% of the total perquisite earned by Mr. Lee in the year.

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 or $1,500 for each committee meeting they chaired. If an independent director attended two meetings on the same date, the independent director received $500 for the second meeting. 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, 2015. The non-independent directors received no compensation for carrying out their duties as directors.

Name	Fees Earned ($)
Allan Buchignani	62,500
Randall Henderson	60,500
Richard Kines	60,000

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. Directors do not have service contracts with the company providing for benefits upon termination.

AUDIT COMMITTEE

At December 31, 2015 the members of the Audit Committee were Randall Henderson, Allan Buchignani and Richard Kines.

Name (Director Since)	Principal Occupation & Biography
Randall Henderson (May 2013) Other Canadian Public Board of Director Memberships Cortex Business Solutions Inc.	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 committee of Cortex Business Solutions Inc. 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) Other Canadian Public Board of Director Memberships N/A	Mr. Buchignani is an accomplished executive with extensive experience in operations, strategic planning, profit & loss management and team building. Currently, he acts 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. 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) Other Canadian Public Board of Director Memberships N/A	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, 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 (the “Committee”) is a committee of the board of directors (the "Board") of Harvest Operations Corp. (“HOC”) to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management’s reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information. The primary objectives of the 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 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 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 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 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 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 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 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 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 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 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 Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member report to the Committee at the next scheduled meeting such pre–approval and the member comply with such other procedures as may be established by the 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 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 Committee shall review risk management policies and procedures of Harvest (i.e. hedging, litigation and insurance).

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

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

12. The Committee shall review the 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 Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the members present the Chair for purposes of the meeting.

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

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

5. The Committee shall meet with the external auditor(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 Committee consider appropriate.

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

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

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

9. Following each meeting, the Committee will report to the Board. Upon request, copies of the materials of such 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 Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board upon request.

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

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

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 Committee Chair.

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

D. Employees

Harvest is focusing on reducing corporate and functional costs in response to the current economic situation and the changes in the Company's asset portfolio. Harvest has reduced its total workforce by 27% in 2015, compared to 2014. The Company reduced its workforce by a total of approximately 34% from January 2015 to the end of March 2016 as a result of further staff reductions occurred during the first quarter of 2016.

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***			

2015	249	116	37	Nil	402
2014	339	146	65	Nil	550
2013	356	153	21	449	979

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, 2015 (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.

B. Related Party Transactions

Other than as disclosed in Notes 12, 13(a), 13(c) and 25 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 2015 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

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these or other matters or amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity.

There were no penalties or sanctions imposed against Harvest or any subsidiary of Harvest by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2015 or any other penalties or sanctions imposed by a court or regulatory body against Harvest or any subsidiary of Harvest that would likely be considered important to a reasonable investor in making an investment decision. No settlement agreements were entered into by Harvest or any subsidiary of Harvest with a court relating to securities legislation or with a securities regulatory authority during the year ended December 31, 2015.

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, 2015.

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 1206582 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.

<u>DIRECTORS</u>

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 profits and 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

2⅛% SENIOR NOTES

The following is a summary of the material attributes and characteristics of the 2⅛% Senior Notes:

The 2⅛% Senior Notes were issued on May 14, 2013 and mature on May 14, 2018. Interest on the 2⅛% Senior Notes is paid semi-annually in arrears on May 14 and November 14 of each year. The 2⅛% 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 2⅛% 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 2⅛% Senior Notes will have the right to require the Corporation to redeem all or any part of such holder's 2⅛% Senior Notes at a redemption price equal to 100% of the principal amount thereof plus accrued and unpaid interest. The 2⅛% Senior Notes is listed on the Singapore Exchange.

6⅞% 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 6⅞% 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 $1 billion revolving credit facility that matures on April 30, 2017, with a syndicate of nine financial institutions. The Credit Facility is secured by KNOC's guarantee (up to $1.0 billion) and by a first floating charge over all of the assets of Harvest

Harvest pays a floating interest rate based on a margin pricing grid based on the credit ratings of KNOC over all of the assets of Harvest and its material subsidiaries. See "Credit Ratings" in this AIF for details. As at December 31, 2015, $926.6 million was drawn on the Credit Facility plus $7.3 million of letters of credit.

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

(a) A requirement to ensure Harvest and its material subsidiaries' tangible assets of at least 60% of consolidated tangible assets;

(b) A requirement to provide cash collateral for the excess, if any, of month end net mark to market hedge liabilities less $100 million, or for month end cash management obligations less $75 million;

(c) A limitation on the payment of distributions to shareholders except for permitted distributions. The basis for permitted distributions include allowed aggregate distributions for the most recent fiscal quarters (including the amount of the proposed distribution) in amounts less than EBITDA minus capital expenditures, cash interest and cash taxes paid during the most recent four fiscal quarters by Harvest and its restricted subsidiaries. As well as there is a provision for other allowed distributions to the extent of proceeds received by Harvest after March 15, 2015 from the issuance of equity or intercompany subordinated debt; and for additional cumulative distributions of $100,000,000; and

(d) Financial compliance covenant is as follows (compliance is certified quarterly for the relevant quarter or the fiscal year, as applicable): Total Debt to Capitalization(1) of 70% or less.

(1) The "Total Debt to Capitalization" covenant was amended on April 22, 2015. For the purposes of calculating this covenant, "Capitalization" will include total debt, related party loans and shareholder's equity. On February 5, 2016, Harvest's syndicate banks consented to waive the Total Debt to Capitalization covenant for the duration of the term of the Credit Facility.

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, 1500, 700 – 2nd Street SW, Calgary, Alberta, Canada T2P 2W1. 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, 2015 can be found in Note 16 of the Corporation's December 31, 2015 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, 2015 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, 2015, 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, 2015. 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, 2015.

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, 2015 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 2015.

ITEM 16C. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The aggregate fees billed by Harvest's external auditors, KPMG LLP ("KPMG") in the last two fiscal years for audit services are as follows:

For the year ended December 31	**2015**	2014
Audit Fees(1)	**$460,000**	$775,000
Audit-Related Fees(2)	**165,000**	679,000
Tax Fees(3)	**28,658**	82,405
All Other Fees(4)	**—**	230,300
Total	**$653,658**	$1,766,705

(1) Audit Fee consists of fees for the audit of our annual consolidated financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) Represents the aggregate fees billed for assurance and related services by Harvest's auditors that are related to the performance of audit or review of Harvest's financial statements and are not included under "Audit Fees" and are primarily composed of services related to Harvest's interim financial statements and services for equity investment stand-alone audits. For 2014, the fees included audit services related to the carve-out financial statements of our Downstream segment and audit of certain property statements.

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

(4) Represents sell-side due diligence engagements related to the sale of our Downstream segment for 2014.

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

Not applicable.

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[2]
2.1	6⅞% Senior Notes Indenture, dated October 4, 2010[1]
2.2	2⅛% Senior Notes Fiscal Agency Agreement, dated May 14, 2013[3]
4.1	Amended and Restated Credit Agreement (Credit Facility) dated April 15, 2014[4]
4.2	Second Amended and Restated Credit Agreement dated April 22, 2015[5]
4.3	First Amending Agreement dated July 15, 2015[6]
4.4	Second Amended Agreement dated February 5, 2016[7]
4.5	6⅞% Senior Notes Indenture, dated October 4, 2010[1]
4.6	2⅛% Senior Notes Fiscal Agency Agreement, dated May 14, 2013[3]
4.7	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

---

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

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

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

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

(5) Incorporated by reference to Form 6-K filed on April 23, 2015

(6) Incorporated by reference to Form 6-K filed on July 17, 2015

(7) Incorporated by reference to Form 6-K filed on March 14, 2016

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/ Sungki Lee
Sungki Lee
Chief Financial Officer

Dated: April 28, 2016

INDEX

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 11, 2016. 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, 2015.

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 interim President and 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, 2015, 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 by our auditors, KPMG 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)

Piljong Sung
Interim President and Chief Executive Officer

(Signed)

Sungki Lee
Chief Financial Officer

Calgary, Alberta
March 11, 2016

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholder and Directors of Harvest Operations Corp.

We have audited the accompanying consolidated financial statements of Harvest Operations Corp., which comprise the consolidated statements of financial position as at December 31, 2015 and December 31, 2014, the consolidated statements of comprehensive loss, changes in shareholder's equity (deficiency) and cash flows for each of the years in the three-year period ended December 31, 2015, 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 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.

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 company'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 audits 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 Corp. as at December 31, 2015 and December 31, 2014, and its consolidated financial performance and its consolidated cash flows for each of the years in the three-year period ended December 31, 2015 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

"signed" KPMG LLP

Chartered Professional Accountants

March 11, 2016
Calgary, Canada

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at *(millions of Canadian dollars)*	Notes	**December 31, 2015**	December 31, 2014
Assets			
Current assets			
Accounts receivable	16	**$ 57.9**	$ 89.8
Prepaid expenses and other		**11.6**	16.5
Derivative contracts	16	**—**	1.9
		69.5	108.2
Non-current assets			
Deferred income tax asset	19	**711.5**	382.5
Exploration and evaluation assets	11	**33.0**	62.1
Property, plant and equipment	9	**2,845.6**	4,109.9
Investments in joint ventures	12	**119.5**	75.8
Goodwill	10	**149.0**	353.1
		3,858.6	4,983.4
Total assets		**$ 3,928.1**	$ 5,091.6
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	16	**166.8**	370.2
Taxes payable	19	**$ 3.7**	$ —
Current portion of provisions	17	**45.7**	37.3
Credit facility	13, 16, 25	**923.8**	—
Derivative contracts	16	**—**	1.2
		1,140.0	408.7
Non-current liabilities			
Long-term debt	13, 16	**1,554.6**	1,916.8
Related party loans	16, 25	**629.9**	396.5
Long-term liability	16, 18	**67.7**	61.5
Non-current provisions	17	**811.2**	773.3
		3,063.4	3,148.1
Total liabilities		**$ 4,203.4**	$ 3,556.8
Shareholder’s equity (deficiency)			
Shareholder's capital		**3,860.8**	3,860.8
Contributed surplus	25	**10.5**	10.3
Deficit		**(4,146.6)**	(2,337.7)
Accumulated other comprehensive income	24	**—**	1.4
Total shareholder's equity (deficiency)		**(275.3)**	1,534.8
Total liabilities and shareholder's equity (deficiency)		**$ 3,928.1**	$ 5,091.6

Commitments *[Note 26]*
Subsequent Events *[Note 13]*

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

(millions of Canadian dollars)	Notes	For the years ended December 31, 2015	2014	2013
Petroleum and natural gas sales		**$ 510.3**	$ 1,046.0	$ 1,101.7
Royalties		**(48.7)**	(149.7)	(153.9)
Loss from joint ventures	12	**(97.3)**	(4.7)	—
Revenues and other income		**364.3**	891.6	947.8
Expenses				
Operating	20	**265.6**	330.5	345.6
Transportation and marketing		**5.2**	17.5	22.6
General and administrative	20	**60.8**	64.8	68.1
Depletion, depreciation and amortization	9	**418.6**	435.2	530.0
Exploration and evaluation	11	**27.5**	10.2	12.3
Losses (gains) on disposition of assets	9	**1.7**	(47.5)	(33.9)
Finance costs	21	**138.1**	95.3	92.2
Derivative contract losses (gains)	16	**5.2**	2.1	(4.4)
Foreign exchange losses	22	**310.5**	126.4	78.7
Impairment	9, 10	**1,256.3**	267.6	24.1
Loss from continuing operations before income tax		**(2,125.2)**	(410.5)	(187.5)
Current income tax expense	19	**5.1**	—	—
Deferred income tax recovery	19	**(336.9)**	(324.9)	(39.4)
Net loss from continuing operations		**(1,793.4)**	(85.6)	(148.1)
Net loss from discontinued operations	8	**(15.5)**	(354.6)	(633.8)
Net loss		**$ (1,808.9)**	$ (440.2)	$ (781.9)
Other comprehensive loss ("OCL")				
Items that may be reclassified to net income				
Gains (losses) on designated cash flow hedges, net of tax	16, 24	**(1.4)**	1.3	(1.1)
Gains (losses) on foreign currency translation		**—**	(9.9)	7.9
Reclassification of cumulative foreign currency translation on disposal of subsidiary	24	**—**	44.1	—
Items that will not be reclassified to net income				
Actuarial gains (losses), net of tax	24	**—**	(5.7)	18.1
Comprehensive loss		**$ (1,810.3)**	$ (410.4)	$ (757.0)

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

CONSOLIDATED STATEMENTS OF CHANGES IN Shareholder's EQUITY (DEFICIENCY)

(millions of Canadian dollars)	Notes	Shareholder's Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income (Loss) ("AOCI")	Total Shareholder's Equity (Deficiency)
Balance at December 31, 2014		$ 3,860.8	$ 10.3	$ (2,337.7)	$ 1.4	$ 1,534.8
Loss on derivatives designated as cash flow hedges, net of tax	24	—	—		(1.4)	(1.4)
Shareholder loan	25	—	0.2	—	—	0.2
Net loss		—	—	(1,808.9)	—	(1,808.9)
Balance at December 31, 2015		**$ 3,860.8**	**$ 10.5**	**$ (4,146.6)**	**$ —**	**$ (275.3)**
Balance at December 31, 2013		$ 3,860.8	$ 4.3	$ (1,893.2)	$ (32.7)	$ 1,939.2
Gains on derivatives designated as cash flow hedges, net of tax	24	—	—	—	1.3	1.3
Losses on foreign currency translation	24	—	—	—	(9.9)	(9.9)
Reclassification of cumulative foreign currency translation losses on disposal of subsidiary	24	—	—	—	44.1	44.1
Actuarial losses, net of tax	24	—	—	—	(5.7)	(5.7)
Shareholder loan	25	—	6.0	—	—	6.0
Transfer of cumulative actuarial losses to deficit	24	—	—	(4.3)	4.3	—
Net loss		—	—	(440.2)	—	(440.2)
Balance at December 31, 2014		$ 3,860.8	$ 10.3	$ (2,337.7)	$ 1.4	$ 1,534.8
Balance at December 31, 2012		$ 3,860.8	$ —	$ (1,111.3)	$ (57.6)	$ 2,691.9
Losses on derivatives designated as cash flow hedges, net of tax	24	—	—	—	(1.1)	(1.1)
Gains on foreign currency translation	24	—	—	—	7.9	7.9
Actuarial gains, net of tax	24	—	—	—	18.1	18.1
Shareholder loan	25	—	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

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

		For the years ended December 31		
(millions of Canadian dollars)	Notes	**2015**	2014	2013
Cash provided by (used in)				
Operating Activities				
Net loss		**$ (1,808.9)**	$ (440.2)	$ (781.9)
Items not requiring cash				
Loss from joint ventures	12	**97.3**	4.7	—
Depletion, depreciation and amortization	8, 9	**418.6**	448.0	612.8
Non-cash finance costs	8, 17, 21	**54.7**	27.1	24.8
Unrealized losses on derivative contracts	16	**0.8**	0.7	0.5
Unrealized losses on foreign exchange	8, 22	**308.3**	103.3	40.8
Impairment of exploration and evaluation assets	11	**27.5**	9.4	11.5
Losses (gains) on disposition of assets	8, 9	**1.7**	(47.7)	(34.1)
Loss on disposition of Downstream Subsidiary	8	**15.5**	56.6	—
Gain on redemption of convertible debentures		**—**	—	(3.6)
Deferred income tax recovery	8, 19	**(336.9)**	(232.8)	(64.2)
Impairment	8, 9, 10	**1,256.3**	446.9	483.0
Other non-cash items		**11.5**	8.7	(0.1)
Realized foreign exchange loss on senior unsecured credit facility		**—**	—	1.3
Settlement of decommissioning and environmental remediation liabilities	17	**(15.6)**	(14.0)	(19.6)
Change in non-cash working capital	23	**(66.2)**	112.2	(70.6)
Cash from (used in) operating activities		**$ (35.4)**	$ 482.9	$ 200.6
Financing Activities				
Credit facility (repayment) borrowings, net	13	**304.4**	(169.4)	293.8
Borrowing on senior unsecured credit facility		**—**	—	395.4
Repayment of senior unsecured credit facility		**—**	—	(396.7)
Repayment of promissory note		**—**	(12.3)	(11.9)
Borrowings from related party loans	25	**148.5**	120.0	80.0
Issuance of senior notes, net of issuance costs	13	**—**	—	634.4
Redemption of convertible debentures	13	**—**	—	(627.2)
Cash from (used in) financing activities		**$ 452.9**	$ (61.7)	$ 367.8
Investing Activities				
Additions to property, plant and equipment	8, 9	**(229.7)**	(695.9)	(741.4)
Additions to exploration and evaluation assets	11	**(1.2)**	(22.3)	(16.7)
Property dispositions, net of acquisitions	9	**41.2**	237.4	160.5
Net cash inflow from disposition of Downstream subsidiary	8	**—**	37.9	—
Corporate acquisition, net of cash acquired	7	**(34.9)**	—	—
Investment in joint ventures	12	**(93.0)**	(26.7)	—
Distributions received from joint ventures	12	**9.6**	2.3	—
Change in non-cash working capital	23	**(109.5)**	47.1	21.6
Cash used in investing activities		**$ (417.5)**	$ (420.2)	$ (576.0)
Change in cash		**—**	1.0	(7.6)
Effect of exchange rate changes on cash		**—**	(1.0)	—
Cash, at beginning of the period		**—**	—	7.6
Cash at end of the period		**$ —**	$ —	$ —
Interest paid		**$ 75.5**	$ 82.1	$ 78.4

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2015, 2014 and 2013
(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

1. Nature of Operations and Structure of the Company

Harvest Operations Corp. ("Harvest", "HOC" 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.

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 1500, 700 – 2nd Street SW, Calgary, Alberta, Canada T2P 2W1.

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").

These consolidated financial statements were approved and authorized for issue by the Board of Directors on March 11, 2016.

On November 13, 2014, Harvest completed the sale of its wholly-owned subsidiary North Atlantic Refining Limited ("North Atlantic" or "Downstream"). Results of Downstream have been presented as discontinued operations and the comparative consolidated statements of comprehensive loss have been adjusted to show the discontinued operation separately from continuing operations (also see note 8 – Discontinued Operations).

Basis of Measurement
The consolidated financial statements have been prepared on the historical cost basis except for 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. Changed in Accounting Policy

(a) New and amended accounting standards adopted

There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2015.

(b) New standards and interpretation issued but not yet adopted
On May 28, 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", which specifies how and when to recognize revenue as well as requiring entities to provide users of financial statements with more disclosure. The standard supersedes IAS 18 "Revenue", IAS 11 "Construction Contracts", and related interpretations. IFRS 15 will be effective for annual periods beginning on or after January 1, 2018. Application of the standard is mandatory and early adoption is permitted. Harvest is currently evaluating the impact of adopting IFRS 15 on its consolidated financial statements.

On July 24, 2014, the IASB issued IFRS 9 "Financial Instruments" to replace IAS 39 "Financial Instruments: Recognition and Measurement". IFRS 9 includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for calculating impairment on financial assets, and the new general hedge accounting. No changes were introduced for the classification and measurement of financial liabilities, except for the recognition of changes in own credit risk in other comprehensive income for liabilities designated at fair value through profit or loss. IFRS 9 is effective for years beginning on or after January 1, 2018. Harvest is currently evaluating the impact of adopting IFRS 9 on its consolidated financial statements.

In January 2016, the IASB issued IFRS 16 "Leases" to replace IAS 17 "Leases". IFRS 16 requires lessees to recognize most leases on the statement of financial position using a single recognition and measurement model. IFRS 16 will be effective for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15. IFRS 16 will be applied by Harvest on January 1, 2019. Harvest is currently evaluating the impact on its consolidated financial statements.

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 material 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(1)	Petroleum refining and marketing	Canada	100

(1) Sold on November 13, 2014 (see note 8 – Discontinued Operations)

(b) Interests in Joint Arrangements

A joint arrangement is an arrangement in which two or more parties have joint control established by a contractual agreement. Joint control requires unanimous consent for decisions regarding the relevant activities of the arrangement. A joint arrangement is either a joint operation, whereby the parties have rights to the assets and obligations for the liabilities, or a joint venture, whereby the parties have rights to the net assets.

Interests in joint operations are recognized in the consolidated financial statements by including Harvest's share of assets, liabilities, revenues and expenses of the arrangement.

Interests in joint ventures are accounted for using the equity method of accounting. Under the equity method of accounting, interests in joint ventures are initially recognized at cost, with the carrying value subsequently increased or decreased to reflect the Company's proportionate share of the profit or loss of the investee after the date of acquisition. Distributions received from an investee reduce the carrying value of the Company's investment. When necessary, adjustments are made to investee financial statements to align accounting policies of investees with those applied by the Company in its consolidated financial statements.

The carrying values of Harvest's equity accounted investments are reviewed at each reporting date to determine whether any indicators of impairment are present. If an indicator of impairment is identified, the recoverable amount of the investment is estimated. If the carrying value of the investment exceeds the estimated recoverable amount, an impairment charge is recognized.

Unrealized gains resulting from transactions with joint ventures are eliminated, to the extent of the Company's interest in the joint venture. For sales of products or services from the Company to its joint ventures, unrealized gains are eliminated against the carrying value of the investment.

(c) Revenue Recognition

Revenues associated with the sale of crude oil, natural gas, natural gas liquids and refined products are recognized when significant risk and rewards of ownership have been transferred, which is considered to occur when title passes to customers and payment has either been received or collection is reasonably certain. Revenues for retail services related to Downstream operations were recorded when the services were provided. Revenues are measured at the fair value of the consideration received or receivable.

(d) 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 impaired. 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 impaired.

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 adjusts prospectively, if appropriate.

(ii) Downstream

PP&E related to the refining assets were recorded at cost. General maintenance and repair costs were expensed as incurred. Major replacements and capital maintenance projects such as turnaround costs were capitalized. Improvements that increase or prolong the service life or capacity of an asset were capitalized.

Depreciation

When significant parts of an item of PP&E have different useful lives, they were accounted for as separate items (major components). Depreciation of recorded cost less the residual value was 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 dispose ("FVLCD") 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 FVLCD, discounted cash flows, future developments, and recent market transactions are taken into account, if available. These calculations are corroborated by valuation multiples or other available fair value indicators. Inputs are those that an independent market participant would consider appropriate.

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 the consolidated statements of comprehensive loss.

(e) Capitalized Interest

Interest on major development projects is capitalized until the project is complete, ready for its intended use, or if development is suspended 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.

(f) Assets Held for Sale and Discontinued Operations

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.

Non-current assets and disposal groups are classified and presented as discontinued operations if the assets or disposal groups are disposed of or classified as held for sale and:

- the assets or disposal groups are a major line of business or geographical area of operations;
- the assets or disposal groups are part of a single coordinated plan to dispose of a separate major line of business or geographical area of operations; or
- the assets or disposal groups are a subsidiary acquired solely for the purpose of resale.

The assets or disposal groups that meet these criteria are measured at the lower of the carrying amount and FVLCD, 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. Comparative period consolidated statements of financial positions are not restated.

The results of discontinued operations are shown separately in the consolidated statements of comprehensive loss, and comparative figures are restated.

(g) 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 indicate possible 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, unless the Company determines there is a better method of allocating the goodwill on disposition.

(h) 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 consolidated statements of comprehensive loss 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 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 using a risk-free rate.

(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.

(i) 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.

(j) Post-Employment Benefits

Prior to its disposal, Harvest's Downstream operations maintained 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 was actuarially determined by an independent actuary 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 included the current service costs and the net interest expense on the net obligation. Net interest expense was calculated by applying the discount rate to the net defined benefit asset or liability. Prior to the disposal, Harvest recognized the benefit plan expenses under operating expenses in the consolidated statements of comprehensive loss. Harvest did not have any past service costs arising from plan amendments, curtailment or restructuring.

Pension plan assets were 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 were recognized in other comprehensive income immediately, and were not reclassified to the consolidated statements of comprehensive loss in subsequent periods.

(k) 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 the consolidated statements of comprehensive loss in the period in which they arise.

Harvest's Downstream operations' functional currency was the U.S. dollar, while Harvest's presentation currency is the Canadian dollar. Therefore, the Downstream operations' assets and liabilities were translated at the period-end exchange rates, while revenues and expenses were translated using monthly average rates. Up until the disposal of Downstream, translation gains and losses relating to the foreign operations were included in accumulated other comprehensive income as a separate component of shareholder's equity. Upon disposal, the cumulative foreign currency translation differences were reclassified to the consolidated statements of comprehensive loss.

(l) 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 the rights to receive cash flows from the assets have expired or when the Company has transferred substantially all risks and rewards of ownership.

Financial assets, financial liabilities and derivatives are measured at fair value on initial recognition. Measurement in subsequent periods depends on the financial instrument's classification, as described below.

- Fair value through profit or loss
  Financial assets and liabilities classified as held-for-trading or designated as at fair value through profit or loss are initially recognized and subsequently measured at fair value with changes in those fair values charged immediately to earnings.

- Held-to-maturity investments, loans and receivables and other financial liabilities
  Held-to-maturity investments, loans and receivables, and other financial liabilities are initially recognized at fair value, net of directly attributable transaction costs, and are subsequently measured at amortized cost using the effective interest method.

- Available-for-sale financial assets
  Non-derivative financial assets may be designated as available for sale so long as they are not classified in another category above. Available-for-sale financial assets are initially recognized at fair value, net of directly attributable transaction costs, and are subsequently measured at fair value with changes in fair value recognized in OCI, net of tax. Transaction costs related to the purchase of available-for-sale assets are recognized in the statements of income. Amounts recognized in OCI for available-for-sale financial assets are charged to earnings when the asset is derecognized or when there is a significant or prolonged decrease in the value of the asset.

Financial assets and liabilities are offset and the net amount is reported on 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.

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 executory contracts.

(m) 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 the consolidated statements of comprehensive loss, except for the effective portion of cash flow hedges, which is recognized in other comprehensive loss.

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 items 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 loss, while any ineffective portion is recognized immediately in the consolidated statements of comprehensive loss. Amounts recognized in other comprehensive loss are transferred to the consolidated statements 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 loss 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 loss is transferred to the consolidated statements of comprehensive loss. 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 loss remain in other comprehensive loss until the forecast transaction affects the consolidated statements of comprehensive loss.

(n) 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.

(o) Fair Value Measurement

Harvest measures derivatives at fair value at each balance sheet date and, for the purposes of business combinations and impairment testing, uses FVLCD to determine the fair value of some of its non-financial assets.

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 consolidated 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. Significant Accounting Judgments, Estimates and Assumptions

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. Harvest has identified the following areas where significant estimates and judgments are required. Further information on each of these areas and how they impact various accounting policies are described below and also in relevant notes to the consolidated financial statements. Changes in estimates are accounted for prospectively.

(a) ***Joint arrangements (note 4(b) and 12)***

Judgment is required to determine whether or not 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.

In addition, judgment is required in determining whether joint arrangement structured through a separate vehicle is a joint operation or joint venture and involves determining whether the legal form and contractual arrangements give the Company direct rights to the assets and obligations for the liabilities. Other facts and circumstances are also assessed by management, including but not limited to, the Company's rights to the economic benefits of assets and its involvement and responsibility for settling liabilities associated with the arrangement. This often requires significant judgment. A different conclusion about both joint control and whether the arrangement is a joint venture or joint operation may materially impact the accounting.

On April 23, 2014, Harvest entered into two joint arrangements with KERR Canada Co. Ltd. ("KERR"): Deep Basin Partnership ("DBP") and HK MS Partnership ("HKMS") (also see note 12). Unanimous consent must be obtained from the shareholders for decisions about relevant activities that impact the returns on investment. Such activities include but are not limited to the approval of the overall capital program and budget. Based on management's assessment, Harvest concluded that both joint arrangements are joint ventures as neither KERR nor Harvest has a direct interest in the underlying assets or liabilities. These joint ventures have been recognized using the equity method of accounting. However, based on the terms of the agreement, which provide for differing proportions of earnings based on ownership percentages that are not representative of the economic substance, Harvest cannot simply apply its percentage ownership to pick up the net income from these joint ventures. Therefore, Harvest applies a hypothetical liquidation at book value ("HLBV") method to calculate its equity share of net income for each reporting period. HLBV takes a balance sheet approach in calculating the earnings Harvest should recognize based on the change in Harvest's economic interest in the net assets in the partnerships under the provisions of the joint venture agreements in a liquidation scenario.

(b) ***Reserves (note 4(d), 9 and 10)***

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.

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.

As the economic assumptions used may change, such changes may impact the reported financial position and results, which include E&E, PP&E, goodwill, DD&A, provisions for decommissioning liabilities and deferred tax assets.

On an annual basis, the Company engages qualified, independent reserves evaluators 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 ("UOP") calculation and the matching of capitalized costs with the benefit of production. The calculation of the UOP rate of DD&A will be impacted to the extent that actual production in the future is different from current forecasted production based on total proved reserves or future development cost estimate changes.

(c) Impairment of long-lived assets (note 4(d), 9 and 10)

Long-lived assets (goodwill and PP&E) 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. The determination of whether such indicators exist requires significant judgment.

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 and directly impact the timing and amount of impairment. These assumptions may change as new information become available. If, after E&E expenditure is capitalized, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalized amount is written off in the consolidated statements of comprehensive loss in the period when the new information becomes available.

The recoverable amounts of CGUs and individual assets are determined based on the higher of VIU calculations and estimated FVLCD. To determine the recoverable amounts under VIU, Harvest uses reserve estimates for both the Upstream and BlackGold operating segments. The estimates of reserves, future commodity prices, discount rates, operating expenses and future development costs require significant judgments. FVLCD is determined using judgments, see note 5(f) below for further discussion.

(d) ***Provisions (note 4(h) and 17)***

In the determination of decommissioning liability provision, 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. The provisions at the reporting date represents management's best estimate of the present value of the future decommissioning costs required.

(e) Income taxes (note 4(i) and 19)

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 (which are impacted by production and sales volumes, oil and natural gas prices, reserves, operating costs, capital expenditures, general and administrative expenses and finance costs) and the judgment about 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.

(f) Fair value measurements (note 4(d), 4(o), 9, 10 and 16)

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.

6. Segment Information

Harvest's operating segments are determined based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by Harvest's chief operating decision makers. The Company's reportable segments are:

- Upstream Operations, which consists of exploration, development, production and subsequent sale of petroleum, natural gas and natural gas liquids in western Canada.
- BlackGold Oil Sands, which is an oil sands project located near Conklin, Alberta. Phase 1 of the project is designed to produce 10,000 barrels of bitumen per day. The project is currently in the commissioning phase.

Harvest's Downstream segment was sold during 2014 and has been classified as discontinued operations (see note 8).

	Year Ended December 31								
	Upstream			BlackGold			Total		
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Petroleum and natural gas sales	**$ 510.3**	$ 1,046.0	$ 1,101.7	**$ —**	$ —	$ —	**$ 510.3**	$ 1046.0	$ 1,101.7
Royalties	**(48.7)**	(149.7)	(153.9)	**—**	—	—	**(48.7)**	(149.7)	(153.9)
Loss from joint ventures	**(97.3)**	(4.7)	—	**—**	—	—	**(97.3)**	(4.7)	—
Revenues and other income	**364.3**	891.6	947.8	**—**	—	—	**364.3**	891.6	947.8
Expenses									
Operating	**251.5**	330.5	345.6	**14.1**	—	—	**265.6**	330.5	345.6
Transportation and marketing	**5.2**	17.5	22.6	**—**	—	—	**5.2**	17.5	22.6
General and administrative	**57.7**	64.8	68.1	**3.1**	—	—	**60.8**	64.8	68.1
Depletion, depreciation and amortization	**418.1**	435.2	530.0	**0.5**	—	—	**418.6**	435.2	530.0
Exploration and evaluation	**27.5**	10.2	12.3	**—**	—	—	**27.5**	10.2	12.3
Losses (gains) on disposition of assets	**1.7**	(47.5)	(33.9)	**—**	—	—	**1.7**	(47.5)	(33.9)
Derivative contract losses (gains)	**5.2**	2.1	(4.4)	**—**	—	—	**5.2**	2.1	(4.4)
Impairment	**765.3**	267.6	24.1	**491.0**	—	—	**1,256.3**	267.6	24.1
Operating loss	**$ (1,167.9)**	$ (188.8)	$ (16.6)	**$ (508.7)**	$ —	$ —	**$ (1,676.6)**	$ (188.8)	$ (16.6)
Finance costs							**138.1**	95.3	92.2
Foreign exchange loss							**310.5**	126.4	78.7
Current income tax expense							**5.1**	—	—
Deferred income tax recovery							**(336.9)**	(324.9)	(39.4)
Net loss from continuing operations							**(1,793.4)**	(85.6)	(148.1)
Net loss from discontinued operations							**(15.5)**	(354.6)	(633.8)
Net loss							**$ (1,808.9)**	$ (440.2)	$ (781.9)

	Year ended December 31								
	Upstream			BlackGold			Total		
Capital Additions	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Additions to PPE	**$ 145.3**	$ 386.2	$ 305.6	**$ 66.0**	$ 283.5	$ 444.5	**$ 211.3**	$ 669.7	$ 750.1
Additions to E&E	**1.2**	22.3	16.7	**—**	—	—	**1.2**	22.3	16.7
Corporate acquisition (note 7)	**51.8**	—	—	**—**	—	—	**51.8**	—	—
PP&E & E&E dispositions, net of acquisitions	**(130.5)**	(301.1)	(155.6)	**—**	0.2	0.7	**(130.5)**	(300.9)	(154.9)
Net capital additions	**$ 67.8**	$ 107.4	$ 166.7	**$ 66.0**	$ 283.7	$ 445.2	**$ 133.8**	$ 391.1	$ 611.9

	Total Assets	Investments in Joint Ventures	PP&E	E&E	Goodwill
December 31, 2015					
Upstream	**$ 2,917.9**	**$ 119.5**	**$ 1,835.0**	**$ 33.0**	**$ 149.0**
BlackGold	**1,010.2**	**—**	**1,010.6**	**—**	**—**
Total	**$ 3,928.1**	**$ 119.5**	**$ 2,845.6**	**$ 33.0**	**$ 149.0**
December 31, 2014					
Upstream	$ 3,656.8	$ 75.8	$ 2,675.3	$ 62.1	$ 353.1
BlackGold	1,434.8	—	1,434.6	—	—
Total	$ 5,091.6	$ 75.8	$ 4,109.9	$ 62.1	$ 353.1

7. Business Combination

On February 27, 2015, Harvest acquired all of the issued and outstanding common shares of Hunt Oil Company of Canada, Inc. ("Hunt"). Hunt was a private oil and gas company with operations immediately offsetting Harvest's lands and production in the Deep Basin area of Alberta.

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:

Consideration		
Cash	$	37.1
		37.1
Fair value of net assets acquired		
Cash	$	2.2
Accounts receivable		0.6
Prepaid expenses		0.2
Property, plant and equipment		45.1
Exploration and evaluation assets		6.7
Accounts payable and accrued liabilities		(6.1)
Decommissioning liability		(3.2)
Deferred income tax liability		(8.4)
	$	37.1

The final review of the fair value of the purchase price allocation was completed at December 31, 2015.

These consolidated financial statements incorporate the results of operations of Hunt from February 27, 2015. For the year ended December 31, 2015, the assets acquired contributed $2.6 million of revenues and $1.4 million to revenues less operating and transportation expenses. If the acquisition had been completed on the first day of 2015, Harvest's revenues for the year ended December 31, 2015 would have been $0.5 million higher and revenues less operating and transportation expenses would have been $0.3 million higher.

On October 1, 2015, the property, plant & equipment and exploration and evaluation assets were contributed to the Deep Basin Partnership (see note 12 – Investment in Joint Ventures and note 9 – PP&E).

8. Discontinued Operations

Downstream operations included 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 was located in the Province of Newfoundland and Labrador. On November 13, 2014, Harvest closed the sale of its wholly owned Downstream segment for net proceeds of approximately $70.5 million subject to post-closing adjustments. The Downstream segment was classified as discontinued operations as at December 31, 2014. Results of the Downstream segment are presented as discontinued operations for the current and prior periods.

The purchase and sale agreement to sell the Downstream segment triggered an impairment assessment during the third quarter of 2014. As a result of this assessment, Downstream recorded an impairment loss of $179.3 million in its refinery CGU relating to the PP&E to reflect a recoverable amount of $nil at December 31, 2014. This amount was included in the operating loss from discontinued operations for the year ended December 31, 2014. The recoverable amount was based on the asset's FVLCD. The FVLCD was determined in accordance with the terms of the purchase and sale agreement, which is level 3 of the fair value hierarchy.

As it was no longer probable for Downstream to utilize deferred tax assets of $92.1 million, it was written down to $nil as at December 31, 2014. Harvest completed a strategic tax planning transaction during the third quarter of 2014, which resulted in an increase of deferred tax assets in the amount of $247.6 million. Harvest also realized a capital loss of $1.6 billion ($796 million taxable capital loss) on the sale of the Downstream segment, of which none has been recognized in the deferred tax asset. See note 18 - Income Taxes.

Harvest recorded an additional loss of $15.5 million related to the disposal of the Downstream segment during the year ended December 31, 2015, which has been included in the net loss from discontinued operations (2014 - $56.6 million).

	Year Ended December 31,		
	2015	2014	2013
Refined products sales	**$ —**	$ 3,432.1	$ 4,416.9
Expenses			
Purchased products for resale and processing	—	3,250.0	4,327.4
Operating	—	209.8	233.1
Transportation and marketing	—	6.0	5.4
General and administrative	—	0.5	0.6
Depletion, depreciation and amortization	—	12.8	82.8
Gains on disposition of assets	—	(0.2)	(0.2)
Impairment and other charges	—	179.3	458.9
Operating loss from discontinued operations	**$ —**	$ (226.1)	$ (691.1)
Finance costs	—	1.5	2.0
Foreign exchange gains [(1)]	—	(21.7)	(34.5)
Loss before income tax from discontinued operations	**$ —**	$ (205.9)	$ (658.6)
Income tax expense	—	92.1	(24.8)
Net loss from discontinued operations	**$ —**	$ (298.0)	$ (633.8)
Loss on disposal of the Downstream subsidiary[(2)]	**15.5**	56.6	—
Net income from discontinued operations	**$ (15.5)**	$ (354.6)	$ (633.8)

(1) The unrealized foreign exchange gain was $21.6 million for the year ended December 31, 2014 (2013 - $34.3 million).
(2) Relates to a post-closing adjustment for working capital during the year ended December 31, 2015. Loss on disposal includes the reclassification of cumulative foreign currency translation loss from AOCI of $44.1 million during the year ended December 31, 2014.

The following table summarizes the components of the discontinued operations cash flows:

	Year Ended December 31, 2014		
	2015	2014	2013
Cash flow used in operating activities	**$ —**	$ (60.0)	$ (177.4)
Cash flow from financing activities	—	129.1	226.8
Cash flow used in investing activities	—	(35.5)	(56.3)
Effect of exchange rate changes on cash	—	(1.0)	—
Total cash inflow (outflow)	**$ —**	$ 32.6	$ (6.9)

Net cash inflow from the disposal of Downstream subsidiary for the year ended December 31, 2014 was $37.9 million, calculated based on the net cash consideration received of $70.5 million less Downstream's total ending cash balance of $32.6 million.

9. Property, Plant and Equipment ("PP&E")

	Upstream		BlackGold		Total	
Cost:						
As at December 31, 2013[1]	$	5,272.3	$	1,138.8	$	6,411.1
Additions		386.2		283.5		669.7
Property acquisitions		3.1		0.2		3.3
Disposals		(500.2)		—		(500.2)
Change in decommissioning liabilities		116.6		12.1		128.7
Transfer from E&E		7.2		—		7.2
As at December 31, 2014	$	5,285.2	$	1,434.6	$	6,719.8
Additions		145.3		66.0		211.3
Corporate acquisition (note 7)		45.1		—		45.1
Disposals, net of property acquisitions		(212.5)		—		(212.5)
Change in decommissioning liabilities		78.7		1.5		80.2
As at December 31, 2015	**$**	**5,341.8**	**$**	**1,502.1**	**$**	**6,843.9**
Accumulated depletion, depreciation, amortization and impairment losses:						
As at December 31, 2013[1]	$	2,106.1	$	—	$	2,106.1
Depreciation, depletion and amortization		435.2		—		435.2
Disposals		(199.0)		—		(199.0)
Impairment		267.6		—		267.6
As at December 31, 2014	$	2,609.9	$	—	$	2,609.9
Depreciation, depletion and amortization		418.1		0.5		418.6
Disposals		(91.5)		—		(91.5)
Impairment		570.3		491.0		1,061.3
As at December 31, 2015	**$**	**3,506.8**	**$**	**491.5**	**$**	**3,998.3**
Net Book Value:						
As at December 31, 2015	**$**	**1,835.0**	**$**	**1,010.6**	$	**2,845.6**
As at December 31, 2014	$	2,675.3	$	1,434.6	$	4,109.9

(1) The total carrying amount of property, plant and equipment excludes the Downstream segment, which has been discontinued.

General and administrative costs directly attributable to PP&E addition activities of $12.3 million have been capitalized during the year ended December 31, 2015 (2014 – $23.4 million; 2013 – $19.6 million). Borrowing costs relating to the development of BlackGold assets have been capitalized within PP&E during the year ended December 31, 2015 in the amount of $9.7 million (2014 – $33.4 million; 2013 – $19.8 million), at a weighted average interest rate of 4.4% (2014 – 4.7%; 2013 – 4.8%). PP&E additions also include non-cash additions relating to the BlackGold deferred payment of $0.8 million (December 31, 2014 – $1.6 million) (see note 18).

At December 31, 2015, the BlackGold oil sands assets of $1.0 billion (December 31, 2014 – $1.4 billion) were excluded from the asset base subject to depreciation, depletion and amortization. In early 2015, the BlackGold oil sands central processing facility was mechanically completed, however, no depletion expense was incurred for the year ended December 31, 2015 as Harvest uses the unit-of-production method and the BlackGold assets currently have no production. During the year ended December 31, 2015, the BlackGold segment recognized impairment expense of $491.0 million (2014, 2013 - $nil) against its PP&E in the BlackGold cash generating unit. Impairment was triggered by a decline in commodity prices and a delay in the project startup date. The recoverable amounts were estimated at the assets' VIU, which is classified as a level 3 fair value measurement, based on the net present value of pre-tax cash flows from proved, probable and possible reserves estimated by an independent reserve evaluator.

CGU	December 31, 2015 Impairment Expense	Recoverable Amount	Pre-Tax Discount Rate(1)	Impairment Sensitivity: 200 bps increase in discount rate	Impairment Sensitivity: 10% decrease in forward commodity prices
BlackGold	$ 491.0	$ 959.1	12%	$ 210.0	$ 269.0

(1) A pre-tax discount rate of 12% was used for proved and probable reserves at December 31, 2015 and a pre-tax discount rate of 15% was used for possible reserves to calculate the recoverable amount.

During the year ended December 31, 2015, Upstream recorded an impairment expense of $570.3 million. Of this total, $560.2 million related to Upstream CGU impairment and all CGUs except for two out of sixteen were impaired during the year ended December 31, 2015. Upstream impairment was triggered by lower forecasted commodity prices, underperforming assets and increased estimated capital costs in the Bellshill area. The recoverable amounts for respective CGUs were estimated at their FVLCD, which is classified as a level 3 fair value measurement, based on the net present value of pre-tax cash flows from proved plus probable oil and gas reserves estimated by an independent reserve evaluator and the estimated fair value of undeveloped land. A discount rate in the range of 11% - 16.5% was used to determine the recoverable amount of $965.8 million for the CGUs impaired during the year. A 200 basis point increase in the discount rate would result in an additional $60 million of impairment for oil CGUs and $8 million increase in gas CGUs. A 10% decrease in forward commodity prices would result in additional impairment of $193 million for oil CGUs and $32 million for gas CGUs.

The following forecast commodity prices were used for impairment as at December 31, 2015:

Year	WTI Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	WCS Crude Oil ($Cdn/bbl)	AECO Gas ($Cdn/Mmbtu)	US$/Cdn$ Exchange Rate
2016	44.67	55.89	44.64	2.57	0.7350
2017	55.20	66.47	54.52	3.14	0.7667
2018	63.47	73.21	60.32	3.47	0.8017
2019	71.00	81.35	67.42	3.80	0.8167
2020	74.77	84.57	70.47	3.99	0.8333
2021	78.24	87.88	73.50	4.13	0.8417
2022	81.75	92.01	77.25	4.30	0.8417
2023	85.37	96.24	80.95	4.48	0.8417
2024	87.32	98.17	83.09	4.60	0.8417
2025	88.90	99.94	84.56	4.70	0.8417
Thereafter(1)	+1.8%/year	+1.8%/year	+1.8%/year	+1.8%/year	0.8417

(1) Represents the average escalation percentage in each year after 2025 to the end of reserve life

During the year ended December 31, 2014, $131.8 million was impaired in the North Alberta Light Oil CGU, $100.8 million in the East Saskatchewan Light Oil CGU and $35.0 million in the South Alberta Gas CGU, for a total of $267.6 million. During the year ended December 31, 2013 $24.1 million was impaired in the South Alberta Gas CGU.

The remainder of the Upstream impairment of $10.1 million related to assets held for sale. The sale of certain Upstream oil and gas assets in the Willesden Green area closed on February 1, 2016. As such, these assets have been classified as assets held for sale at December 31, 2015. As a result of this classification, the assets were tested for impairment and written down to its recoverable amount of $nil.

On May 1, 2015 Harvest closed the disposition of certain non-core oil and gas assets in Eastern Alberta for the total of $28.4 million in net proceeds. In addition, Harvest disposed of certain gas assets to the Deep Basin Partnership in the amount of $57.4 million for partnership units (see note 7 – Business Combination and note 12 – Investment in Joint Ventures) for a net loss of $2.0 million. Together with other insignificant dispositions of Upstream assets, Harvest recognized a net loss on disposition of assets of $1.7 million for the year ended December 31, 2015 (2014 – $47.5 million net gain; 2013 – $33.9 million net gain) relating to the de-recognition of PP&E, E&E, goodwill and decommissioning and environmental liabilities.

10. Goodwill

As at December 31, 2013	$	379.8
Disposals		(26.7)
As at December 31, 2014	$	353.1
Disposals		(9.1)
Impairment		(195.0)
As at December 31, 2015	**$**	**149.0**

Goodwill 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 of the Upstream segment is determined based on its FVLCD.

Market participants generally apply the market multiple enterprise value per barrel of proved and probable reserves ("EV/2P") when estimating the fair value of an oil and gas company. As such, Harvest determined the fair value of its Upstream segment by applying the observed EV/2P multiple of comparable public companies to its proved and probable reserves (Level 2 fair value input). Harvest's proved and probable reserves were estimated by an independent qualified reserves evaluator and are subject to significant judgment.

At December 31, 2015, the EV/2P multiples ranged from $5.90 to $10.30 per barrel of proved and probable reserves for a group of comparable companies of similar size, operating metrics and production profile. Harvest used an average EV/2P multiple of $7.50 per barrel of proved and probable reserves when determining the implied fair value of Harvest's Upstream segment. As at December 31, 2015, the carrying value exceeded the recoverable amount by $195.0 million; as such, goodwill impairment was recorded (2014 and 2013 – $nil).

11. Exploration and Evaluation Assets ("E&E")

As at December 31, 2013	$	59.4
Additions		22.3
Property acquisitions		3.1
Disposition		(6.1)
Impairment		(9.4)
Transfer to property, plant and equipment		(7.2)
As at December 31, 2014	$	62.1
Additions		1.2
Corporate acquisition (note 7)		6.7
Dispositions, net of acquisitions		(9.5)
Impairment		(27.5)
As at December 31, 2015	**$**	**33.0**

The Company determined certain E&E costs to be unsuccessful and not recoverable, which were expensed as follows, together with pre-licensing expenses. Impaired E&E costs were deemed not to be technically feasible and commercially viable.

	Year ended December 31		
	2015	2014	2013
Pre-licensing costs	**$ —**	$ 0.8	$ 0.8
Impairment	**27.5**	9.4	11.5
E&E expense	**$ 27.5**	$ 10.2	$ 12.3

12. Investment in Joint Ventures

On April 23, 2014, Harvest entered into the DBP and HKMS joint ventures with KERR. The principal place of operations for both DBP and HKMS is in Canada. DBP was established for the purposes of exploring, developing and producing from oil and gas properties in the Deep Basin area in Northwest Alberta.

Amounts contributed by KERR have been spent by the DBP to purchase land, drill and develop partnership properties in the Deep Basin area. As the initial funding from KERR is consumed and additional funds are required to fund the development program, each partner is entitled to participate in and fund the additional work programs, however to the extent only one partner funds, its partnership interest will be increased and the other partner's interest will be diluted proportionately. Harvest will be obligated to fund the balance of the program to the extent of its share of partnership distributions received.

The preferred partnership units issued to KERR at inception provides certain preference rights, including a put option right exercisable after 10.5 years, whereby KERR could cause DBP to redeem all its preferred partnership units for consideration equal to its initial contribution plus a specified internal rate of return. If DBP 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 (the "top-up obligation"). This top-up obligation is accounted for by Harvest at fair value through profit and loss and is estimated using a probabilistic model of the estimated future cash flows of the DBP (level 3 fair value inputs). The cash flow forecast is based on management's internal assumptions of the volumes, commodity prices (see note 7 – PP&E for pricing at December 31, 2015), royalties, operating costs and capital expenditures specific to the DBP. As at December 31, 2015, the fair value of the top-up obligation was estimated as $2.0 million (December 31, 2014 - $nil), using discount rate of 29%. This top-up obligation has been included in the derivative contract losses in the statement of comprehensive loss and in the long-term liability at December 31, 2015 (see note 18 – Long-Term Liability). Once KERR achieves the minimum after-tax internal rate of return on its investment, Harvest is entitled to increased return on its investment.

HKMS was formed for the purposes of constructing and operating a gas processing facility, which is now 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. On the earlier of 10.5 years after the formation of HKMS or when KERR achieves a specified internal rate of return, Harvest will have the right but not the obligation to purchase all of KERR's interest in HK MS Partnership for nominal consideration.

The following tables show the balance and the movement in the investments in joint ventures account during the period:

	December 31, 2015			December 31, 2014		
		Investment	**Ownership interest**		Investment	Ownership interest
Deep Basin Partnership ("DBP")	**$**	**50.5**	**81.17%**	$	49.2	77.81%
HK MS Partnership ("HKMS")		**69.0**	**69.93%**		26.6	47.01%
Investments in joint ventures	**$**	**119.5**		$	75.8	

		DBP		HKMS
Balance as at December 31, 2013	$	—	$	—
Initial investment on April 23, 2014		54.9		—
Additional investments		—		26.7
Share of losses		(4.6)		(0.1)
Distributions		(2.3)		—
Dilution gain recognized on disposal of assets		1.2		—
Balance as at December 31, 2014	$	49.2	$	26.6
Additional investments		107.2		43.2
Share of income (losses)		(104.2)		6.9
Distributions		(1.9)		(7.7)
Dilution gain recognized on disposal of assets		0.2		—
Balance as at December 31, 2015	**$**	**50.5**	**$**	**69.0**

The initial investment of $54.9 million in DBP represents the net book value of the assets Harvest contributed to the partnership. As KERR's ownership interest in DBP is considered a liability and not an equity interest, Harvest's initial unrecognized dilution gain on the transaction of approximately $91.5 million will be recognized over 10.5 years based on

KERR's interest being converted to equity as distributions are made to KERR during the term. For the year ended December 31, 2015, Harvest recognized a dilution gain of $0.2 million (2014 - $1.2 million).

The following tables summarize the financial information of the DBP and HKMS joint ventures:

	December 31, 2015		December 31, 2014	
	DBP	HKMS	DBP	HKMS
Cash and cash equivalents	**$ 0.1**	**$ 0.1**	$ 1.7	$ —
Other current assets	**22.1**	**13.3**	51.7	0.6
Total current assets	**$ 22.2**	**$ 13.4**	$ 53.4	$ 0.6
Non-current assets	**212.8**	**102.6**	170.7	79.0
Total assets[(1)]	**$ 235.0**	**$ 116.0**	$ 224.1	$ 79.6
Current liabilities	**$ 48.9**	**$ 1.8**	$ 46.4	$ 13.6
Non-current financial liabilities	**131.1**	**109.2**	125.5	61.4
Other non-current liabilities	**6.0**	**4.8**	4.2	4.7
Total liabilities[(1)]	**$ 186.0**	**$ 115.8**	$ 176.1	$ 79.7
Net assets (liabilities) [(1)]	**$ 49.0**	**$ 0.2**	$ 48.0	$ (0.1)

(1) Balances represent 100% share of DBP and HKMS

	Year Ended December 31			
	2015		2014[(2)]	
	DBP	HKMS	DBP	HKMS
Revenues	**$ 30.2**	$ **19.8**	$ 9.9	$ —
Impairment	**(61.5)**	**—**	—	—
Depletion, depreciation and amortization	**(43.9)**	**(3.1)**	(9.0)	—
Operating expenses and other	**(26.3)**	**(1.5)**	(3.8)	(0.1)
Finance costs	**(2.7)**	**(15.0)**	(1.7)	—
Net income (loss)[(1)]	**$ (104.2)**	$ **0.2**	$ (4.6)	$ (0.1)

(1) Balances represent 100% share of DBP and HKMS
(2) For the period from April 23, 2014 to December 31, 2014

The following table summarizes 100% of DBP's contractual obligations and estimated commitments as at December 31, 2015:

	Payments Due by Period				
	1 year	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Preferred distribution liability payments	$ 2.2	$ —	$ —	$ 131.1	$ 133.3
Firm processing commitment	22.8	45.5	45.5	75.8	189.6
Decommissioning and environmental liabilities[(1)]	—	0.2	0.2	13.4	13.8
Total	$ 25.0	$ 45.7	$ 45.7	$ 220.3	$ 336.7

(1) Represents the undiscounted obligation by period.

The following table summarizes 100% of HKMS's contractual obligations and estimated commitments as at December 31, 2015:

	Payments Due by Period				
	1 year	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Decommissioning and environmental liabilities[(1)]	$ —	$ —	$ —	$ 13.7	$ 13.7
Total	$ —	$ —	$ —	$ 13.7	$ 13.7

(1) Represents the undiscounted obligation by period.

Related party transactions

<u>Deep Basin Partnership</u>
As the operator of the DBP assets, Harvest has collected revenues and paid expenses on behalf of DBP. In addition, as managing partner, Harvest charges DBP for marketing fees and general and administrative expenses. For the year ended December 31, 2015, Harvest charged DBP a marketing fee of $0.3 million (2014 - $0.1 million) and general and administrative expenses of $0.9 million (2014 - $1.1 million). As at December 31, 2015, $14.1 million remains outstanding to DBP (December 31, 2014 - $3.8 million).

A cash call payable of $nil is also outstanding to DBP as at December 31, 2015 relating to the estimated drilling and completion costs to be incurred on behalf of the DBP (December 31, 2014 - $44.4 million).

On October 1, 2015, Harvest contributed certain gas assets to DBP in the amount of $57.4 million. The resulting loss of $2.0 million has been included in loss on disposition of assets in the consolidated statements of comprehensive loss (see note 7 – Business Combination and note 9 – PP&E).

<u>HK MS Partnership</u>
As the managing partner, Harvest incurs expenditures relating to the construction of the midstream facility on behalf of HKMS. In addition, Harvest also charged HKMS general and administrative expenses of $0.1 million (2014 - $nil). As at December 31, 2015, the balance of $1.1 million remains outstanding to HKMS (December 31, 2014 - $0.6 million).

13. Long-Term Debt

		December 31, 2015		December 31, 2014
Credit facility	**$**	**—**	$	617.6
6⅞% senior notes due 2017 (US$500 million)		**685.7**		572.0
2⅛% senior notes due 2018 (US$630 million)		**868.9**		727.2
Long-term debt outstanding	**$**	**1,554.6**	$	1,916.8

a) Credit Facility

On April 22, 2015, Harvest amended its $1 billion syndicated revolving credit facility and replaced it with a $940 million revolving credit facility that matures on April 30, 2017, with a syndicate of eight financial institutions. On July 15, 2015 Harvest secured a $60 million commitment from a new lender to increase the borrowing capacity of the new facility to $1 billion. The facility is secured by KNOC's guarantee (up to $1.0 billion) and by a first floating charge over all of the assets of Harvest and its material subsidiaries. A guarantee fee of 0.37% per annum of the principal balance is payable to KNOC semi-annually. Also see note 25 - Related Party Transactions.

Under the amended credit facility, applicable interest and fees will be based on a margin pricing grid based on the credit ratings of KNOC. The financial covenants under the previous credit facility were deleted and replaced with a new covenant: Total Debt to Capitalization ratio of 70% or less. At December 31, 2015, Harvest was in violation of the debt covenant and the carrying value of the credit facility, $923.8 million, was classified as a current liability. Subsequent to December 31, 2015, Harvest's syndicate banks consented to a waiver of this covenant effective until April 30, 2017.

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 the Company's discretion. At December 31, 2015, Harvest had $926.6 million drawn under the credit facility (December 31, 2014 - $620.7 million). The carrying value of the credit facility includes $2.8 million of deferred financial fees at December 31, 2015 (December 31, 2014 - $3.1 million). For the year ended December 31, 2015, interest charges on the credit facility borrowings aggregated to $17.6 million (2014 - $23.6 million; 2013 - $20.3 million), reflecting an effective interest rate of 2.0% (2014 – 3.4%; 2013 – 3.0%).

b) 6⅞% Senior Notes

On October 4, 2010, Harvest issued US$500 million of 6⅞% 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 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, 2015.

c) 2⅛% Senior Notes

On May 14, 2013, Harvest issued US$630 million senior unsecured notes due May 14, 2018 with a coupon rate of 2⅛% for net proceeds of US$626.1 million. Interest on the 2⅛% 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 (see note 25 - 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 was included in "finance costs" in the consolidated statements of comprehensive loss (see note 21).

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

As at December 31, 2015 and 2014, there are 386,078,649 of common shares outstanding.

15. Capital Structure

Harvest considers its capital structure to be its credit facility, long term debt, related party loans, and shareholder's equity.

		December 31, 2015		December 31, 2014
Credit facility(1)	**$**	**926.6**	$	620.7
6⅞% senior notes (US$500 million)(1)(2)		**692.0**		580.1
2⅛% senior notes (US$630 million)(1)(2)		**871.9**		730.9
Related party loans (US$290 million and CAD$200 million)(3)		**601.4**		397.2
	$	**3,091.9**	$	2,328.9
Shareholder's equity (deficiency)		**(275.3)**		1,534.8
	$	**2,816.6**	$	3,863.7

(1) Excludes capitalized financing fees.
(2) Face value converted at the period end exchange rate.

(3) As at December 31, 2014, related party loans comprised of US$170 million from ANKOR and CAD$200 million from KNOC (see note 25 – Related Party Transactions).

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.

The Company's capital structure and liquidity needs are met through cash generated from operations, proceeds from asset dispositions, joint arrangements, borrowings under the credit facility, related party loans, long-term debt issuances and capital injections by KNOC.

Harvest evaluates its capital structure using the same financial covenants as the ones externally imposed under the Company's debt commitments. Harvest was not in compliance with its debt covenant under the credit facility at December 31, 2015, however subsequent to December 31, 2015 the financial covenant was waived. See note 13 – Long-Term Debt.

16. Financial Instruments

a) Fair Values

Financial instruments of Harvest consist of accounts receivable, accounts payable and accrued liabilities, borrowings under the credit facility, derivative contracts, senior notes, related party loans and long term liability. Cash and derivative 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 following hierarchy based on the amount of observable inputs used to value the instrument:

Level 1: quoted (unadjusted) prices in active markets for identical assets or liabilities. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: other techniques for which all inputs which have a significant effect on the recorded fair value are observable, either directly or indirectly.

Level 3: techniques which use inputs that have a significant effect on the recorded fair value that are not based on observable market data.

All financial instruments are level 2, except for the 2⅛% senior notes, which are level 1 and $2.0 million of the long-term liability, which is level 3. Also see note 18 – Long-Term Liability. During the year ended December 31, 2015, there were no transfers among Levels 1, 2 and 3.

	December 31, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Loans and Receivables Measured at Cost				
Accounts receivable	$ 57.9	$ 57.9	$ 89.8	$ 89.8
Held for Trading				
Fair value of derivative contracts	—	—	1.9	1.9
Total Financial Assets	**$ 57.9**	**$ 57.9**	**$ 91.7**	**$ 91.7**
Financial Liabilities				
Held for Trading				
Fair value of derivative contracts	$ —	$ —	$ 1.2	$ 1.2
Long-term liability	2.0	2.0	—	—
Measured at Amortized Cost				
Accounts payable and accrued liabilities	166.8	166.8	370.2	370.2
Credit facility	923.8	926.6	617.6	620.7
6⅞% senior notes	685.7	494.2	572.0	561.9
2⅛% senior notes	868.9	870.5	727.2	727.2
Related party loans	629.9	384.3	396.5	367.9
Long-term liability	54.5	29.0	61.5	47.6
Total Financial Liabilities	**$ 3,331.6**	**$ 2,873.4**	**$ 2,746.2**	**$ 2,696.7**

Non-derivative financial instruments
Due to the short term maturities of accounts receivable and accounts payable and accrued liabilities, their carrying values approximate their fair values.

The credit facility bears a floating market rate, thus, the fair value approximates the carrying value (excluding deferred financing charges). The carrying value of the credit facility includes $2.8 million of deferred financing charges at December 31, 2015 (December 31, 2014 – $3.1 million).

The fair value of the 2⅛% senior notes was based on the quoted market price of the notes on the Singapore Exchange as at December 31, 2015 (Level 1 fair value input), which includes the benefit of the guarantee offered by KNOC. The fair value of the 6⅞% senior notes was estimated based on the period end trading price of the notes on the secondary market (Level 2 fair value input), using a discount rate of 29%.

The fair values of the related party loans and long-term liability measured at amortized cost are estimated by discounting the future interest and principal payments using the current market interest rates of instruments with similar terms. At December 31, 2015, the rate used in determining the fair values of the related party loans and long-term liability was 29% (December 31, 2014 – 8.5% for related party loans and 9.5% for the long-term liability).

Derivative financial instruments

Harvest enters into derivative contracts with various counterparties, principally financial institutions with investment grade credit ratings. The fair values of the derivative contracts are determined based on the quoted forward prices of similar transactions observable in active markets. The fair values of the derivative 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, however there were no derivative contracts outstanding as at December 31, 2015.

	December 31, 2014			
	Assets		Liability	
Natural gas swap	$	1.9	$	—
Power swap		—		(1.2)
	$	1.9	$	(1.2)

b) Financial Assets and Financial Liabilities Subject to Offsetting

The following table presents the recognized financial instruments that are offset, or subject to enforceable master netting arrangements or other similar agreements but not offset, as at December 31, 2015 and 2014, 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				
	Gross assets (liabilities)	**Gross assets (liabilities) offset**	**Net amount presented**	**Related financial instruments that are not offset**	**Net**
December 31, 2015					
Financial assets					
Account receivable[i]	$ 0.3	$ (0.3)	$ —	$ —	$ —
	$ 0.3	$ (0.3)	$ —	$ —	$ —
Financial Liabilities					
Account payable and accrued liabilities[i]	$ (0.3)	$ 0.3	$ —	$ —	$ —
	$ (0.3)	$ 0.3	$ —	$ —	$ —
December 31, 2014					
Financial assets					
Account receivable[i]	$ 2.2	$ (2.1)	$ 0.1	$ —	$ 0.1
Derivative contracts[ii]	1.9	—	1.9	(0.8)	1.1
	$ 4.1	$ (2.1)	$ 2.0	$ (0.8)	$ 1.2
Financial Liabilities					
Account payable and accrued liabilities[i]	$ (2.1)	$ 2.1	$ —	$ —	$ —
Derivative contracts[ii]	(1.2)	—	(1.2)	0.8	(0.4)
	$ (3.3)	$ 2.1	$ (1.2)	$ 0.8	$ (0.4)

i. Various master netting agreements with counterparties that allow net settlement of payments in the normal course of business.

ii. 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 settled for 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) Derivative 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. When the hedged item is settled, the related effective portion of the realized gains and losses is removed from AOCI and included in petroleum and natural gas sales (see note 24). The ineffective portion of the unrealized and realized gains and losses are recorded in the consolidated statements of comprehensive loss.

Derivative contracts (gains) losses recorded in the consolidated statements of comprehensive loss 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								
	2015			2014			2013		
	Realized losses	**Unrealized (gains) losses**	**Total**	Realized (gains) losses	Unrealized losses	Total	Realized gains	Unrealized losses	Total
Power	$ **4.2**	$ **(1.2)**	$ **3.0**	$ 1.6	$ 0.7	$ 2.3	$ (3.1)	$ 0.5	$ (2.6)
Crude Oil	**—**	**—**	**—**	—	—	—	(0.4)	—	(0.4)
Currency	**0.2**	**—**	**0.2**	(0.2)	—	(0.2)	(1.4)	—	(1.4)
Top-up obligation (note 12)	**—**	**2.0**	**2.0**	—	—	—	—	—	—
	$ **4.4**	$ **0.8**	$ **5.2**	$ 1.4	$ 0.7	$ 2.1	$ (4.9)	$ 0.5	$ (4.4)

Harvest did not have any derivative contracts outstanding at December 31, 2015.

(ii) Credit Risk

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.

Derivative Contract Counterparties

Harvest is exposed to credit risk from the counterparties to its derivative 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.

Harvest's maximum exposure to credit risk relating to the above classes of financial assets at December 31, 2015 and 2014 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, 2015					
		Overdue AR				
	Current	< 30 days	> 30 days, ≤ 60 days	> 60 days, ≤ 90 days	> 90 days[(2)]	Total
Accounts receivable[(1)]	$ 45.7	$ 0.5	$ 9.4	$ —	$ 2.3	**$ 57.9**

(1) Net of payables subject to master netting arrangements or other similar agreements. See note 16(b).
(2) Net of $1.3 million of allowance for doubtful accounts.

	December 31, 2014					
		Overdue AR				
	Current	< 30 days	> 30 days, ≤ 60 days	> 60 days, ≤ 90 days	> 90 days[(2)]	Total
Accounts receivable[(1)]	$ 86.2	$ 0.8	$ 0.4	$ 0.1	$ 2.3	$ 89.8

(1) Net of payables subject to master netting arrangements or other similar agreements. See note 17(b).
(2) Net of $1.6 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, related party loans and 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 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.

The following tables provide an analysis of Harvest's financial liability maturities based on the remaining terms of the liabilities including the related interest charges as at December 31, 2015 and 2014:

	December 31, 2015				
	<1 year	>1 year ≤3 years	>3 years ≤5 years	>5 years	Total
Accounts payable and accrued liabilities[(1)]	$ 166.8	$ —	$ —	$ —	$ 166.8
Credit facility and interest	15.8	929.0	—	—	944.8
6⅞% senior notes and interest	47.6	739.6	—	—	787.2
2⅛% senior notes and interest	18.5	909.0	—	—	927.5
Related party loans and interest	—	702.5	—	—	702.5
Long-term liability	14.4	23.8	19.0	47.9	105.1
Total	**$ 263.1**	**$ 3,303.9**	**$ 19.0**	**$ 47.9**	**$ 3,633.9**

(1) Net of receivables subject to master netting arrangements or other similar agreements. See note 16(b).

	December 31, 2014				
	<1 year	>1 year ≤3 years	>3 years ≤5 years	>5 years	Total
Accounts payable and accrued liabilities[1]	$ 370.2	$ —	$ —	$ —	$ 370.2
Credit facility and interest	19.1	646.2	—	—	665.3
6⅞% senior notes and interest	40.0	659.8	—	—	699.8
2⅛% senior notes and interest	15.5	31.1	738.6	—	785.2
Related party loans and interest	—	225.4	258.3	—	483.7
Long-term liability	—	21.7	19.0	38.1	78.8
Derivative contracts liability	1.2	—	—	—	1.2
Total	**$ 446.0**	**$ 1,584.2**	**$ 1,015.9**	**$ 38.1**	**$ 3,084.2**

(1) Net of receivables subject to master netting 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 based on KNOC's credit rating. Harvest's 6⅞% and 2⅛% 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, 2015 increased or decreased by approximately 25 basis points with all other variables held constant, pre-tax loss for the year would change by $2.3 million (2014 - $1.6 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 6⅞% and 2⅛% senior notes, related party loans from ANKOR and US$171 million loan from KNOC (US$120 million drawn at December 31, 2015) and LIBOR based loans are denominated in U.S. dollars, collectively US$1.4 billion (2014 - US$1.3 billion). 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.

If the U.S. dollar strengthened or weakened by 10% relative to the Canadian dollar, the impact on pre-tax loss and other comprehensive loss due to the translation of financial instruments held at December 31 would be as follows:

	December 31, 2015		December 31, 2014	
	(Increase) decrease in loss before tax[(1)]	**(Increase) decrease in OCL before tax [(1)]**	(Increase) decrease in loss before tax[(1)]	(Increase) decrease in OCL before tax [(1)]
10% strengthening in U.S. dollar relative to Canadian dollar	**$ (198.9)**	**$ —**	$ (133.1)	$ —
10% weakening in U.S. dollar relative to Canadian dollar	**$ 198.9**	**$ —**	$ 133.1	$ —

(1) The sensitivity to net loss and other comprehensive loss 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 derivative 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. Harvest had no derivative contracts in place at December 31, 2015.

17. Provisions

	Upstream	BlackGold	Total
Decommissioning liabilities at December 31, 2013	$ 709.4	$ 34.3	$ 743.7
Liabilities incurred	8.0	4.2	12.2
Settled during the period	(13.8)	—	(13.8)
Revisions (change in discount rate, estimated timing and costs)	108.6	7.9	116.5
Disposals	(80.9)	—	(80.9)
Accretion	20.7	1.1	21.8
Decommissioning liabilities at December 31, 2014	$ 752.0	$ 47.5	$ 799.5
Environmental remediation at December 31, 2014	7.6	—	7.6
Other provisions at December 31, 2014	3.5	—	3.5
Less current portion	(37.3)	—	(37.3)
Balance at December 31, 2014	$ 725.8	$ 47.5	$ 773.3
Decommissioning liabilities at December 31, 2014	$ 752.0	$ 47.5	$ 799.5
Liabilities incurred	2.3	0.7	3.0
Corporate acquisition	3.2	—	3.2
Settled during the period	(15.6)	—	(15.6)
Revisions (change in estimated timing and costs)	76.4	0.8	77.2
Disposals	(38.9)	—	(38.9)
Accretion	17.2	1.1	18.3
Decommissioning liabilities at December 31, 2015	$ 796.6	$ 50.1	$ 846.7
Environmental remediation at December 31, 2015	6.7	—	6.7
Other provisions at December 31, 2015	3.5	—	3.5
Less current portion	(45.7)	—	(45.7)
Balance at December 31, 2015	**$ 761.1**	**$ 50.1**	**$ 811.2**

Harvest estimates the total undiscounted amount of cash flows required to settle its decommissioning and environmental remediation liabilities to be approximately $1.4 billion at December 31, 2015 (December 31, 2014 – $1.4 billion), which will be incurred between 2016 and 2075. A risk-free discount rate of 2.3% (December 31, 2014 – 2.3%) and inflation rate of

1.7% (December 31, 2014 – 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

Under the BlackGold oil sands engineering, procurement and construction ("EPC") contract, $94.9 million of EPC costs are to be paid in equal installments, without interest, over 10 years commencing on the completion of the EPC work. The first two installments were paid on April 30, 2015. As at December 31, 2015, a liability of $62.0 million (December 31, 2014 – $77.8 million) remains outstanding using a discount rate of 5.5% (December 31, 2014 – 4.5%), of which $9.5 million (December 31, 2014 - $19.0 million) is payable within a year and has been included with accounts payable and accrued liabilities.

Also included in long-term liability and other is an accrual related to Harvest's long term incentive program of $1.9 million (December 31, 2014 – $2.7 million) as well as deferred credits of $11.4 million (December 31, 2014 – $nil).

At December 31, 2015, $2.0 million (December 31, 2014 - $nil) was included in the long-term liability relating to the top-up obligation to KERR (see note 12 – Investment in Joint Ventures).

19. Income Taxes

Income tax recovery recognized in net loss from continuing operations:

	Year Ended December 31		
	2015	2014	2013
Current income tax expense	**$ 5.1**	$ —	$ —
Deferred income tax ("DIT") recovery	**(336.9)**	(324.9)	(39.4)
Income tax recovery from continuing operations	**$ (331.8)**	$ (324.9)	$ (39.4)

The income tax recovery, for continuing operations, 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		
	2015	2014	2013
Loss before income tax from continuing operations	**$ (2,125.2)**	$ (410.5)	$ (187.5)
Combined Canadian federal and provincial statutory income tax rate	**26.96%**	27.51%	27.69%
Computed income tax recovery at statutory rates	**$ (572.9)**	$ (112.9)	$ (51.9)
Increased expense (recovery) resulting from the following:			
Difference between current and expected tax rates	**(28.8)**	10.2	4.8
Foreign exchange impact not recognized in income	**41.5**	18.7	8.0
Amended returns and pool balances	**33.9**	0.5	(1.7)
Recognition of previously unrecognized temporary difference (see note 8)	—	(247.6)	—
Unrecognized temporary differences	**133.4**	—	—
Non-deductible goodwill impairment	**52.6**	—	—
Non-deductible expenses (recoveries)	**8.4**	2.0	(1.1)
Other	**0.1**	4.2	2.5
Income tax recovery	**$ (331.8)**	$ (324.9)	$ (39.4)

The tax rate is comprised of the Federal and Provincial statutory tax rates for the Company and its subsidiaries for the years ended December 31, 2015 and 2014. The net change in the combined federal and provincial tax rate is due largely to a decrease in the provincial rate from the sale of the Downstream segment which operated in a province with a 14% tax rate. This was partially offset due to the Government of Alberta increase in the corporate income tax rate from 10% to 12% effective July 1, 2015. The increase to the Alberta tax rate resulted in an additional deferred income tax recovery of $28.8 million, which was recorded in the second quarter of 2015.

Movements in the DIT asset (liability) are as follows:

	PP&E	Decommissioning liabilities	Non-capital tax losses	Other	Total deferred asset (liability)
At December 31, 2013	$ (294.6)	$ 192.4	$ 248.2	$ 2.8	$ 148.8
Recognized in profit or loss	295.1	14.9	(2.5)	17.4	324.9
Recognized in other comprehensive loss	—	—	—	0.9	0.9
Recognized in discontinued operations	(51.0)	(3.3)	(37.0)	(0.8)	(92.1)
At December 31, 2014	$ (50.5)	$ 204.0	$ 208.7	$ 20.3	$ 382.5
Recognized in profit or loss	351.3	27.3	(21.1)	(20.6)	336.9
Recognized in purchase price adjustment (note 7)	(9.3)	0.9	—	—	(8.4)
Recognized in other comprehensive loss	—	—	—	0.5	0.5
At December 31, 2015	**$ 291.5**	**$ 232.2**	**$ 187.6**	**$ 0.2**	**$ 711.5**

As at December 31, 2015, Harvest had approximately $987 million (December 31, 2014 - $811 million) of carry-forward tax losses and approximately $4.0 billion (December 31, 2014 - $4.2 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. 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. A deferred tax asset related to the carry-forward tax losses has been recorded as Harvest expects that future taxable profits, through a combination of future operating results and other tax planning opportunities will be sufficient to utilize the deferred tax asset. As at December 31, 2015 Harvest has not recognized approximately $242 million (December 31, 2014 - $nil) of temporary difference arising from foreign exchange, $253 million (December 31, 2014 - $nil) of non-capital losses and $796 million (December 31, 2014 - $796 million) of capital losses.

As at December 31, 2014, Harvest had a contingent liability relating to an unsettled dispute with the Canada Revenue Agency. During the year with respect to this item, Harvest has recorded a current income tax expense in the amount of $5.3 million in the consolidated statement of comprehensive loss.

20. Operating and General and Administrative ("G&A") Expenses

	Year Ended December 31		
Operating expenses	**2015**	2014	2013
Power and purchased energy	**$ 49.1**	$ 67.6	$ 89.1
Well servicing	**19.6**	39.6	49.9
Repairs and maintenance	**40.7**	53.3	51.7
Lease rentals and property taxes	**34.5**	38.8	37.3
Salaries and benefits	**32.4**	30.9	31.8
Professional and consultation fees	**14.0**	14.2	15.3
Chemicals	**17.8**	19.9	18.7
Processing fees	**30.0**	38.2	36.8
Trucking	**7.4**	13.7	13.9
Other	**20.1**	14.3	1.1
	$ 265.6	$ 330.5	$ 345.6

General and administrative expenses	Year Ended December 31 2015	2014	2013
Salaries and benefits	**$ 51.3**	$ 64.5	$ 60.2
Professional and consultation fees	**7.2**	10.3	13.9
Other	**11.8**	14.0	14.4
G&A capitalized and recovery	**(9.5)**	(24.0)	(20.4)
	$ 60.8	$ 64.8	$ 68.1

21. Finance Costs

	Year ended December 31 2015	2014	2013
Interest and other financing charges	**$ 126.7**	$ 106.7	$ 93.8
Accretion of decommissioning and environmental remediation liabilities	**21.1**	22.0	21.8
Gain on redemption of convertible debentures	—	—	(3.6)
Less: interest capitalized	**(9.7)**	(33.4)	(19.8)
	$ 138.1	$ 95.3	$ 92.2

22. Foreign Exchange

	Year ended December 31 2015	2014	2013
Realized losses on foreign exchange	$ **2.2**	$ 1.5	$ 3.5
Unrealized losses on foreign exchange	**308.3**	124.9	75.2
	$ **310.5**	$ 126.4	$ 78.7

23. Supplemental Cash Flow Information

	Year ended December 31 2015	2014	2013
Source (use) of cash:			
Accounts receivable	**$ 32.5**	$ 44.2	$ 6.7
Prepaid expenses, long-term deposit and other	**5.1**	(46.5)	35.3
Accounts payable and accrued liabilities	**(205.8)**	173.2	(114.7)
Net changes in non-cash working capital	**(168.2)**	170.9	(72.7)
Changes relating to operating activities	**(66.2)**	112.2	(70.6)
Changes relating to investing activities	**(109.5)**	47.1	21.6
Post-closing adjustments related to discontinued operations (note 8)	**15.5**	—	—
Reclass of long-term liability to accounts payable	**(7.6)**	11.4	—
Reclass of accounts payable to promissory note	**—**	—	(24.2)
Add: Other non-cash changes	**(0.4)**	0.2	0.5
	$ (168.2)	$ 170.9	$ (72.7)

24. Accumulated Other Comprehensive Income ("AOCI")

	Foreign Currency Translation Adjustment	Designated Cash Flow Hedges, Net of Tax	Actuarial Loss, Net of Tax	Total
Balance at December 31, 2013	$ (34.2)	$ 0.1	$ 1.4	$ (32.7)
Reclassification to net loss of gains on cash flow hedges	—	(2.1)	—	(2.1)
Gains on derivatives designated as cash flow hedges, net of tax	—	3.4	—	3.4
Actuarial loss, net of tax	—	—	(5.7)	(5.7)
Transfer of cumulative actuarial loss to deficit	—	—	4.3	4.3
Losses on foreign currency translation	(9.9)	—	—	(9.9)
Reclassification of cumulative foreign currency translation to loss from discontinued operations	44.1	—	—	44.1
Balance at December 31, 2014	$ —	$ 1.4	$ —	$ 1.4
Reclassification to net loss of gains on cash flow hedges	—	(12.4)	—	(12.4)
Gains on derivatives designated as cash flow hedges, net of tax	—	11.0	—	11.0
Balance at December 31, 2015	**$ —**	**$ —**	**$ —**	**$ —**

The following table summarizes the impacts of the cash flow hedges on the OCL:

	Year ended December 31, 2015					
	After-tax			Pre-tax		
	2015	2014	2013	**2015**	2014	2013
Gains reclassified from OCL to revenues	**$ (12.4)**	$ (2.1)	$ (2.8)	**$ (17.0)**	$ (3.0)	$ (3.9)
Gains recognized in OCL	**11.0**	3.4	1.7	**15.1**	4.7	2.4
Total	**$ (1.4)**	$ 1.3	$ (1.1)	**$ (1.9)**	$ 1.7	$ (1.5)

25. Related Party Transactions

a) *Related party loans*

On April 2, 2015, Harvest entered into an US$171 million loan agreement with KNOC, repayable within a year from the date of the first drawing which was on April 10, 2015, at an interest rate of 3.42% per annum. As at December 31, 2015, the carrying value of this loan was $170.2 million including $166.1 million (US$120 million) principal and $4.1 million interest accrual. Interest expense was $3.8 million for the year ended December 31, 2015. During the fourth quarter of 2015, the maturity date was extended to December 31, 2017 and the interest rate was increased to 5.91% per annum effective December 31, 2015. See note 15 – Capital Structure.

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 at December 31, 2015, Harvest had drawn $200 million from the loan agreement (December 31, 2014 - $200 million). The loan amount was recorded at fair value on initial recognition by discounting the future cash payments at the rate of 7% which is considered the market rate applicable to the liability. As at December 31, 2015, the carrying value of the KNOC loan was $193.2 million (December 31, 2014 - $191.2 million). The difference between the fair value and the loan amount was recognized in contributed surplus. As at December 31, 2015, $10.5 million (December 31, 2014 - $10.3 million) has been recognized in contributed surplus. For the year ended December 31, 2015, interest expense of $13.7 million was recorded (2014 - $11.5 million; 2013 - $nil) and $16.7 million of interest payable remained outstanding as at December 31, 2015 (December 31, 2014 - $4.9 million).

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, 2015, Harvest's related party loan from ANKOR included $235.3 million (December 31, 2014 - $197.2 million) of principal and $14.6 million (December 31, 2014 - $3.1 million) of accrued interest. Interest expense was $10.0 million for the year ended December 31, 2015 (2014 - $8.7 million; 2013 - $8.1 million).

The related party loans are unsecured and the loan agreements contain no restrictive covenants.

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		
	2015	2014	2013
Short-term benefits	**$ 4.1**	$ 5.2	$ 5.1
Other long-term benefits	**0.6**	0.7	0.7
Termination and other	**0.5**	0.2	—
	$ 5.2	$ 6.1	$ 5.8

c) *Other Related Party Transactions*

	Year ended December 31,			Balance Outstanding: Accounts receivable as at December 31,	Accounts receivable as at December 31,	Accounts payable as at December 31,	Accounts payable as at December 31,
	2015	2014	2013	**2015**	2014	**2015**	2014
Revenues							
KNOC[(1)]	**$ —**	$ 1.7	4.1	**$ —**	$ —	**$ —**	$ —
G&A Expenses							
KNOC[(2)]	**$ (5.6)**	$ (3.7)	$ (3.5)	**$ —**	$ 0.5	**$ 0.8**	$ 3.7
Finance costs							
KNOC[(3)]	**$ 7.5**	$ 4.0	$ 2.8	**$ —**	$ —	**$ 3.5**	$ 2.7

(1) Global Technology and Research Centre ("GTRC") was used as a training and research facility for KNOC. In 2014 and 2013, the amount is related to a geological study performed by the GTRC on behalf of KNOC. The GTRC was closed at the end of 2015.

(2) Amounts relate to the reimbursement from KNOC for general and administrative expenses incurred by the GTRC. Also included is Harvest's reimbursement to KNOC for secondee salaries paid by KNOC on behalf of Harvest.

(3) Charges from KNOC for the irrevocable and unconditional guarantee they provided on Harvest's 2⅛% senior notes and the senior unsecured credit facility. A guarantee fee of 52 basis points per annum is charged by KNOC on the 2⅛% senior notes and 37 basis points per annum on the credit facility (see note 13 – Long Term Debt).

26. Commitments

The following is a summary of Harvest's estimated commitments as at December 31, 2015:

	Payments Due by Period				
	1 year	2-3 years	4-5 years	After 5 years	Total
Purchase commitments(1)	$ 12.5	$ 21.0	$ 19.0	$ 47.9	$ 100.4
Operating leases	8.2	15.6	14.5	34.7	73.0
Firm processing commitments	19.8	35.6	29.0	70.3	154.7
Firm transportation agreements	18.5	59.9	43.8	59.6	181.8
Employee benefits(2)	4.9	4.8	—	—	9.7
Total	$ 63.9	$ 136.9	$ 106.3	$ 212.5	$ 519.6

(1) Relates to BlackGold oil sands project commitment and revised estimated capital costs for the Bellshill area.
(2) Relates to the long-term incentive plan payments.
(3) See note 16(c) – Financial Instruments for Harvest's long-term debt and related party loan obligations.

27. Supplemental Guarantor Condensed Financial Information

Harvest Breeze Trust No. 1, Harvest Breeze Trust No. 2, Breeze Resources Partnership, Hay River Partnership, and 1496965 Alberta Ltd. (collectively "guarantor subsidiaries") fully and unconditionally guarantees the credit facility and 6⅞% senior notes issued by Harvest. Each of the guarantor subsidiaries is 100% owned by HOC. Prior to the disposal of North Atlantic Refining Limited on November 13, 2014, North Atlantic was also considered a guarantor subsidiary of 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 or material 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 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, 2015

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Assets					
Current assets					
Accounts receivable	$ 57.8	$ 0.1	$ —	$ —	$ 57.9
Prepaid expenses and other	11.6	—	—	—	11.6
Due from affiliates	202.4	142.9	0.3	(345.6)	—
	$ 271.8	$ 143.0	$ 0.3	$ (345.6)	$ 69.5
Non-current assets					
Deferred income tax asset	$ 668.7	$ 42.2	$ 0.6	$ —	$ 711.5
Exploration & evaluation assets	27.7	5.3	—	—	33.0
Property, plant and equipment	2,717.6	126.6	1.4	—	2,845.6
Investment in subsidiaries	(71.6)	—	—	71.6	—
Investment in joint ventures	119.5	—	—	—	119.5
Goodwill	149.0	—	—	—	149.0
Total assets	$ 3,882.7	$ 317.1	$ 2.3	$ (274.0)	$ 3,928.1
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	$ 165.2	$ 1.3	$ 0.3	$ —	$ 166.8
Taxes payable	3.7	—	—	—	3.7
Credit facility	923.8	—	—	—	923.8
Current portion of provisions	45.7	—	—	—	45.7
Due to affiliates	140.7	199.7	5.3	(345.7)	—
	$ 1,279.1	$ 201.0	$ 5.6	$ (345.7)	$ 1,140.0
Non-current liabilities					
Long-term debt	$ 1,554.6	$ —	$ —	$ —	$ 1,554.6
Related party loans	629.9	—	—	—	629.9
Long-term liability	67.7	—	—	—	67.7
Non-current provisions	626.7	184.5	—	—	811.2
Intercompany loan	—	—	0.8	(0.8)	—
Total liabilities	$ 4,158.0	$ 385.5	$ 6.4	$ (346.5)	$ 4,203.4
Shareholder's equity	(275.3)	(68.4)	(4.1)	72.5	(275.3)
Total liabilities and shareholder's equity	$ 3,882.7	$ 317.1	$ 2.3	$ (274.0)	$ 3,928.1

CONDENSED STATEMENTS OF COMPREHENSIVE LOSS
For the year ended December 31, 2015

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Petroleum and natural gas sales	$ 415.1	$ 95.2	$ —	$ —	$ 510.3
Royalties	(36.4)	(12.3)	—	—	(48.7)
Loss from joint ventures	(97.3)	—	—	—	(97.3)
Earnings from equity accounted subsidiaries	(7.3)	—	—	7.3	—
Revenues and other income	274.1	82.9	—	7.3	364.3
Expenses					
Operating	224.4	40.8	0.4	—	265.6
Transportation and marketing	5.9	(0.7)	—	—	5.2
General and administrative	49.9	10.9	—	—	60.8
Depletion, depreciation and amortization	337.4	81.2	—	—	418.6
Exploration and evaluation	23.8	3.7	—	—	27.5
Loss (gain) on disposition of assets	20.2	(18.5)	—	—	1.7
Finance costs	135.6	2.5	—	—	138.1
Derivative contracts losses	5.2	—	—	—	5.2
Foreign exchange losses	310.5	—	—	—	310.5
Impairment	1,184.5	71.8	—	—	1,256.3
Loss from continuing operations before income tax	(2,023.3)	(108.8)	(0.4)	7.3	(2,125.2)
Current income tax expense	5.1				5.1
Deferred income tax recovery	(234.8)	(101.9)	(0.2)	—	(336.9)
Net loss from continuing operations	(1,793.6)	(6.9)	(0.2)	7.3	(1,793.4)
Net loss from discontinued operations	(15.5)	—	—	—	(15.5)
Net loss	$ (1,809.1)	$ (6.9)	$ (0.2)	$ 7.3	$ (1,808.9)
Other comprehensive loss					
Loss on designated cash flow hedges, net of tax	(1.4)	—	—	—	(1.4)
Comprehensive loss	$ (1,810.5)	$ (6.9)	$ (0.2)	$ 7.3	$ (1,810.3)

CONDENSED STATEMENT OF CASH FLOWS
For the year ended December 31, 2015

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Cash provided by (used in) operating activities	$ 183.4	$ (218.8)	$ —	$ —	$ (35.4)
Cash proved by (used in) financing activities	452.9	(49.1)	—	49.1	452.9
Cash provided by (used in) investing activities	(636.3)	267.9	—	(49.1)	(417.5)
Change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents, beginning of year	—	—	—	—	—
Cash and cash equivalents, end of year	$ —	$ —	$ —	$ —	$ —

CONDENSED STATEMENT OF FINANCIAL POSITION
As at December 31, 2014

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Assets					
Current assets					
Accounts receivable	$ 78.7	$ 11.1	$ —	$ —	$ 89.8
Prepaid expenses and other	16.5	—	—	—	16.5
Derivative contracts	1.9	—	—	—	1.9
Due from affiliates	412.0	94.2	0.3	(506.5)	—
	$ 509.1	$ 105.3	$ 0.3	$ (506.5)	$ 108.2
Non-current assets					
Deferred income tax asset	$ 441.7	$ (59.7)	$ 0.5	$ —	$ 382.5
Exploration & evaluation assets	51.4	10.7	—	—	62.1
Property, plant and equipment	3,567.8	540.8	1.3	—	4,109.9
Investment in subsidiaries	(15.3)	—	—	15.3	—
Investment in joint ventures	75.8	—	—	—	75.8
Goodwill	353.1	—	—	—	353.1
Total assets	$ 4,983.6	$ 597.1	$ 2.1	$ (491.2)	$ 5,091.6
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	$ 359.3	$ 10.6	$ 0.3	$ —	$ 370.2
Current portion of provisions	37.3	—	—	—	37.3
Derivative contracts	1.2	—	—	—	1.2
Due to affiliates	91.9	409.8	4.8	(506.5)	—
	$ 489.7	$ 420.4	$ 5.1	$ (506.5)	$ 408.7
Non-current liabilities					
Long-term debt	$ 1,916.8	$ —	$ —	$ —	$ 1,916.8
Related party loans	396.5	—	—	—	396.5
Long-term liability	61.5	—	—	—	61.5
Non-current provisions	584.3	189.0	—	—	773.3
Intercompany loan	—	—	0.8	(0.8)	—
Total liabilities	$ 3,448.8	$ 609.4	$ 5.9	$ (507.3)	$ 3,556.8
Shareholder's equity	1,534.8	(12.3)	(3.8)	16.1	1,534.8
Total liabilities and shareholder's equity	$ 4,983.6	$ 597.1	$ 2.1	$ (491.2)	$ 5,091.6

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the year ended December 31, 2014

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Petroleum and natural gas sales	$ 817.3	$ 228.7	$ —	$ —	$ 1,046.0
Royalties	(114.4)	(35.3)	—	—	(149.7)
Loss from joint ventures	(4.7)	—	—	—	(4.7)
Earnings from equity accounted subsidiaries	(6.1)	—	—	6.1	—
Revenues and other income	692.1	193.4	—	6.1	891.6
Expenses					
Operating	271.1	58.9	0.5	—	330.5
Transportation and marketing	13.8	3.7	—	—	17.5
General and administrative	51.6	13.2	—	—	64.8
Depletion, depreciation and amortization	342.6	92.6	—	—	435.2
Exploration and evaluation	9.6	0.6	—	—	10.2
Gains on disposition of assets	(29.4)	(18.1)	—	—	(47.5)
Finance costs	90.6	4.7	—	—	95.3
Derivative contracts losses	2.1	—	—	—	2.1
Foreign exchange losses	126.4	—	—	—	126.4
Impairment	252.6	15.0	—	—	267.6
Income (loss) from continuing operations before income tax	(438.9)	22.8	(0.5)	6.1	(410.5)
Income tax (recovery) expense	(353.3)	28.5	(0.1)	—	(324.9)
Net loss from continuing operations	(85.6)	(5.7)	(0.4)	6.1	(85.6)
Net loss from discontinued operations	(354.6)	(298.0)	(0.2)	298.2	(354.6)
Net loss	$ (440.2)	$ (303.7)	$ (0.6)	$ 304.3	$ (440.2)
Other comprehensive income (loss)					
Gains on designated cash flow hedges, net of tax	1.3	—	—	—	1.3
Losses on foreign currency translation	—	(9.9)	—	—	(9.9)
Reclassification of cumulative foreign currency translation on disposal of subsidiary	44.1	—	—	—	44.1
Actuarial loss, net of tax	—	(5.7)	—	—	(5.7)
Share of equity accounted comprehensive loss	(15.6)	—	—	15.6	—
Comprehensive loss	$ (410.4)	$ (319.3)	$ (0.6)	$ 319.9	$ (410.4)

CONDENSED STATEMENT OF CASH FLOWS
For the year ended December 31, 2014

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Cash provided by operating activities	$ 371.0	$ 110.2	$ 1.7	$ —	$ 482.9
Cash proved by (used in) financing activities	(41.0)	(135.5)	2.0	112.8	(61.7)
Cash provided by (used in) investing activities	(330.0)	55.2	—	(145.4)	(420.2)
Change in cash and cash equivalents	—	29.9	3.7	(32.6)	1.0
Effect of exchange rate changes on cash	—	(1.0)	—	—	(1.0)
Cash and cash equivalents, beginning of year	—	—	—	—	—
Cash disposed of on sale of Downstream subsidiary	—	(28.9)	(3.7)	32.6	—
Cash and cash equivalents, end of year	$ —	$ —	$ —	$ —	$ —

CONDENSED STATEMENT OF FINANCIAL POSITION
As at December 31, 2013

	Issuer HOC	Guarantor Subsidiaries	Non Guarantor Subsidiaries	Eliminations	Consolidated Totals
Assets					
Current assets					
Accounts receivable	$ 95.2	$ 71.6	$ 2.1	$ —	$ 168.9
Prepaid expenses and other	15.8	48.3	1.6	—	65.7
Derivative 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 and other	5.0	0.6	—	—	5.6
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
Promissory note	—	12.3	—	—	12.3
Current portion of provisions	39.1	—	—	—	39.1
Derivative 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 loans	259.6	—	—	—	259.6
Long term liability	69.5	—	—	—	69.5
Non-current 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 and natural gas sales	$ 852.3	$ 249.4	$ —	$ —	$ 1,101.7
Royalties	(112.9)	(41.0)	—	—	(153.9)
Earnings from equity accounted subsidiaries	22.2	—	—	(22.2)	—
Revenues and other income	761.6	208.4	—	(22.2)	947.8
Expenses					
Operating	279.9	65.4	0.3	—	345.6
Transportation and marketing	22.5	0.1	—	—	22.6
General and administrative	54.7	13.4	—	—	68.1
Depletion, depreciation and amortization	425.3	104.7	—	—	530.0
Exploration and evaluation	11.0	1.3	—	—	12.3
Gains on disposition of assets	(34.0)	0.1	—	—	(33.9)
Finance costs	87.3	4.9	—	—	92.2
Derivative contracts gains	(4.4)	—	—	—	(4.4)
Foreign exchange losses	78.7	—	—	—	78.7
Impairment	13.6	10.5	—	—	24.1
Income (loss) from continuing operations before income tax	(173.0)	8.0	(0.3)	(22.2)	(187.5)
Income tax recovery	(24.8)	(14.5)	(0.1)	—	(39.4)
Net income (loss) from continuing operations	(148.2)	22.5	(0.2)	(22.2)	(148.1)
Net loss from discontinued operations	(633.8)	(634.9)	(1.7)	636.6	(633.8)
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 comprehensive loss	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	$ —	$ —	$ —	$ —	$ —

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, 2015 and 2014 and for the years ended December 31, 2015, 2014 and 2013 in accordance with 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.

Harvest's investment in Deep Basin Partnership ("DBP") is accounted for using the equity method of accounting. Information is first provided in respect of Harvest and its wholly owned subsidiaries, which are consolidated for financial reporting purposes (under the heading "Consolidated Entities") and then in respect of DBP (under the heading "Equity Investment"). All information with respect to DBP reflects Harvest's 81.71% as at December 31, 2015 and 77.8% equity interest in DBP as at December 31, 2014.

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, 2015 and 2014, and changes thereto for the years ended December 31, 2015, 2014 and 2013 are shown in the following table. Note that all Harvest's proved reserves are located within Canada. Proved reserves as of December 31, 2015 and 2014 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.

	Consolidated Entities					Equity Investment			Consolidated Entities and Equity Investment
	Crude Oil	NGLs	Bitumen	Natural Gas	Total	NGLs	Natural Gas	Total	Total
	(MMbbls)	(MMbbls)	(MMbbls)	(Bcf)	(MMBOE)	(MMbbls)	(Bcf)	(MMBOE)	(MMBOE)
January 1, 2013	79.1	9.5	84.9	212.7	208.8	—	—	—	208.8
Revisions of previous estimates (including infill drilling & improved recovery)	(3.8)	0.8	3.2	54.2	9.1	—	—	—	9.1
Purchase of reserves in place	0.4	—	—	0.9	0.6	—	—	—	0.6
Sale of reserves in place	(4.3)	(0.3)	—	(13.2)	(6.8)	—	—	—	(6.8)
Discoveries and extensions	5.4	0.5	—	10.3	7.6	—	—	—	7.6
Production	(8.8)	(1.7)	—	(38.3)	(16.8)	—	—	—	(16.8)
December 31, 2013	**68.1**	**8.8**	**88.1**	**226.6**	**202.5**	**—**	**—**	**—**	**202.5**
Revisions of previous estimates (including infill drilling & improved recovery)	—	0.9	(3.7)	30.8	2.5	—	(1.0)	(0.3)	2.2
Purchase of reserves in place	—	—	—	1.2	0.2	0.7	13.4	2.9	3.1
Sale of reserves in place	(7.2)	(0.8)	—	(20.5)	(11.4)	—	—	—	(11.4)
Discoveries and extensions	1.6	1.1	—	35.3	8.6	1.7	19.6	5.0	13.6
Production	(7.9)	(1.4)	—	(33.0)	(14.7)	(0.1)	(1.1)	(0.2)	(14.9)
December 31, 2014	**54.6**	**8.6**	**84.4**	**240.4**	**187.7**	**2.3**	**30.9**	**7.4**	**195.1**
Revisions of previous estimates (including infill drilling & improved recovery)	(17.7)	(2.8)	(84.4)	(81.9)	(118.6)	(1.0)	(9.4)	(2.5)	(121.1)
Purchase of reserves in place	—	—	—	1.5	0.3	0.2	4.4	0.9	1.2
Sale of reserves in place	(1.3)	(0.1)	—	(5.1)	(2.3)	—	—	—	(2.3)
Discoveries and extensions	0.2	0.6	—	15.8	3.4	0.7	8.3	2.1	5.5
Production	(6.6)	(1.2)	—	(35.6)	(13.7)	(0.3)	(5.3)	(1.2)	(14.9)
December 31, 2015	**29.2**	**5.1**	**—**	**135.1**	**56.8**	**1.9**	**28.9**	**6.7**	**63.5**
Proved Developed									
December 31, 2013	60.8	6.5	—	174.2	96.2	—	—	—	96.2
December 31, 2014	47.4	5.9	—	169.8	81.7	1.0	17.9	3.9	85.6
December 31, 2015	**27.8**	**3.1**	**—**	**118.3**	**50.6**	**1.3**	**24.9**	**5.5**	56.1
Proved Undeveloped									
December 31, 2013	7.3	2.3	88.1	52.4	106.3	—	—	—	106.3
December 31, 2014	7.2	2.7	84.4	70.6	106.0	1.3	13.0	3.5	109.5
December 31, 2015	**1.4**	**1.9**	**—**	**16.8**	**6.2**	**0.5**	**4.0**	**1.2**	**7.4**

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;
- rather Future prices and costs 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.

	Consolidated Entities		**Equity Investment**	
(millions of Canadian dollars)	**December 31, 2015**	December 31, 2014	**December 31, 2015**	December 31, 2014
Future cash inflows	**2,176.3**	12,697.0	**186.5**	389.6
Less future:				
Production costs	**(1,317.8)**	(6,286.5)	**(100.9)**	(128.2)
Development costs	**(112.0)**	(1,314.1)	**(22.5)**	(65.9)
Decommissioning costs	**(948.3)**	(913.9)	**(6.6)**	(4.0)
Income taxes	**—**	—	**(0.5)**	(14.5)
Future net cash flows	**(201.8)**	4,182.5	**56.0**	177.0
Less 10% annual discount	**453.3**	(1,954.9)	**(11.8)**	(67.4)
Standardized measure of discounted future net cash flows	**251.5**	2,227.6	**44.2**	109.6

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:

	Consolidated Entities			Equity Investment	
(millions of Canadian dollars)	**December 31, 2015**	December 31, 2014	December 31, 2013	**December 31, 2015**	December 31, 2014
Future discounted net cash flow, beginning of year	**2,227.6**	2,015.8	2,085.7	**109.6**	—
Sales & transfers of oil and gas produced, net of production costs	**(210.1)**	(565.7)	(602.2)	**(14.7)**	(5.7)
Net change in sales & transfer prices and production costs related to future production	**(2,046.3)**	732.1	165.4	**(86.2)**	14.3
Development costs incurred during the period	**195.6**	620.2	725.7	**72.1**	88.6
Change in future development costs	**348.1**	(540.3)	(510.5)	**(89.8)**	(132.0)
Change due to extensions and discoveries	**25.2**	138.2	141.5	**13.9**	77.2
Accretion of discount	**222.8**	202.5	210.6	**11.5**	4.2
Sales of reserves in place	**(4.5)**	(225.7)	(120.8)	**—**	—
Purchase of reserves in place	**1.7**	3.5	16.0	**6.0**	41.7
Net change in income taxes	**—**	9.4	10.3	**5.5**	(6.0)
Changes due to revisions in timing of future net cash flow and other changes	**(508.6)**	(162.4)	(105.9)	**16.3**	27.3
Future discounted net cash flow, end of year	**251.5**	2,227.6	2,015.8	**44.2**	109.6
Net change for the year	**(1,976.1)**	211.8	(69.9)	**(65.4)**	109.6

Table IV: Results of Operations

For the years ended December 31,

	Consolidated Entities			Equity Investment	
(millions of Canadian dollars)	**2015**	2014	2013	**2015**	2014
Petroleum and natural gas revenues, net of royalties	**461.6**	891.6	947.8	**24.7**	7.7
Less:					
Production costs	**251.5**	330.5	345.6	**19.2**	2.0
Exploration expense	**27.5**	10.2	12.3	**1.4**	—
Depletion, depreciation and amortization (1)	**413.0**	432.1	527.7	**35.9**	7.0
Accretion of decommissioning liability	**18.3**	21.8	21.6	**0.1**	—
Impairment on oil and gas properties	**1,256.3**	267.6	24.1	**48.9**	—
Other (transportation and marketing)	**5.2**	17.5	22.6	**1.4**	0.1
Income tax expense (recovery) (2)	**(224.9)**	(16.8)	13.3	**—**	0.2
Results of operations (excluding corporate overhead and interest costs)	**(1,285.3)**	(171.3)	(19.4)	**(82.2)**	(1.6)

(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 (recovery) for the period.

Table V: Capitalized Costs

(millions of Canadian dollars)	Consolidated Entities December 31, 2015	December 31, 2014	December 31, 2013	Equity Investment December 31, 2015	December 31, 2014
Proved oil and gas properties [1]	**6,806.9**	6,678.5	6,383.4	**255.4**	137.2
Unproven oil & gas properties included in:					
Property, plant and equipment [2]	**—**	10.3	12.8	**4.9**	1.0
Exploration and evaluation assets	**33.0**	62.1	59.4	**5.7**	1.6
Total unproved oil and gas properties	**33.0**	72.4	72.2	**10.6**	2.6
Total capital cost	**6,839.9**	6,750.9	6,455.6	**266.0**	139.8
Accumulated depreciation, depletion and amortization ("DD&A") [3] and impairment on oil and gas properties	**(3,981.3)**	(2,598.1)	(2,097.7)	**(92.2)**	(7.0)
Net capitalized costs	**2,858.6**	4,152.8	4,357.9	**173.8**	132.8

(1) Consolidated entities' proved oil and gas properties exclude $37.0 million of corporate assets as at December 31, 2015 (December 31, 2014 - $31.0 million).

(2) Costs related to incomplete wells as at year end. As at December 31, 2015, Harvest's consolidated entities were in the process of drilling a total of nil gross wells (December 31, 2013 – 4 gross wells) and Harvest's equity investment was in the process of drilling 2 gross wells (December 31, 2014 – 1 gross well).

(3) Consolidated entities' accumulated DD&A excludes accumulated depreciation on corporate assets of $17.0 million as at December 31, 2015 (December 31, 2014 - $11.8 million).

Table VI: Costs Incurred

For the years ended December 31,

(millions of Canadian dollars)	Consolidated Entities 2015	2014	2013	Equity Investment 2015	2014
Property acquisition [1]					
Proved property	**45.1**	3.3	13.7	**41.5**	5.2
Unproved property	**6.7**	3.1	—	**5.5**	—
Total property acquisition costs	**51.8**	6.4	13.7	**47.0**	5.2
Exploration costs	**1.2**	22.3	16.7	**—**	—
Development costs [2]	**285.5**	782.3	790.7	**73.6**	89.9
Total costs incurred [3]	**338.5**	811.0	821.1	**120.5**	95.1

(1) Consolidated entities' property acquisition costs include business and property acquisitions and exclude proceeds received from dispositions of $99.3 million for the year ended December 31, 2015 (2014 - $243.0 million; 2013 - $173.9 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) Consolidated entities' total costs incurred exclude costs related to corporate assets of $6.0 million for the year ended December 31, 2015 (2014 - $16.1 million; 2013 - $4.7 million).

EXHIBIT 12.1

CERTIFICATIONS

I, Piljong Sung, 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 28, 2016

/s/ Piljong Sung
Piljong Sung
Interim President & Chief Executive Officer

EXHIBIT 12.2

CERTIFICATIONS

I, Sungki Lee, 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 28, 2016

/s/ Sungki Lee
Sungki Lee
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, 2015 (the "Report") as filed with the Securities and Exchange Commission on the date hereof, I, Piljong Sung, 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 28, 2016

/s/ Piljong Sung
Piljong Sung
Interim 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, 2015 (the "Report") as filed with the Securities and Exchange Commission on the date hereof, I, Sungki Lee, 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:

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 28, 2016

/s/ Sungki Lee
Sungki Lee
Chief Financial Officer

GLJ PETROLEUM CONSULTANTS

LETTER OF CONSENT

Mr. Wallace Catsirelis
Harvest Operations Corp.
1500, 700 - 2nd Street SW
Calgary, Alberta T2P 2W1

We hereby consent to the use of our name and the inclusion of our report dated February 12, 2016 evaluating the petroleum and natural gas reserves of Harvest Operations Corp. (the "Corporation") as of December 31, 2015, in the Annual Report on Form 20-F for the year ended December 31, 2015 (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 J. Hladyshevsky, P. Eng.
Vice President

MJH/jem

Dated: April 28, 2016
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" or “Harvest”) 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, 2015. The completion date of our report is February 12, 2016.

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.

	Net Reserves Attributable to Harvest Operations Corp.					
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	25,735	113,959	2,955	-	47,683	
Developed non-producing	2,090	4,250	161	-	2,960	
Undeveloped	1,397	16,820	1,953	-	6,153	
Total Proved	29,222	135,028	5,069	-	56,796	100%
Probable Reserves						
Developed	10,168	37,949	844	-	17,337	
Undeveloped	3,691	15,164	1,105	-	7,323	
Total Probable	13,858	53,113	1,949	-	24,660	100%

	Net Reserves Attributable to Harvest’s 81.71% Ownership in Deep Basin Partnership					
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	0.6	24,888	1,310	-	5,458	
Developed non-producing	-	-	-	-	-	
Undeveloped	-	3,952	570	-	1,228	
Total Proved	0.6	28,840	1,879	-	6,687	100%
Probable Reserves						
Developed	0.2	8,725	443	-	1,897	
Undeveloped	-	1,841	198	-	505	
Total Probable	0.2	10,566	641	-	2,402	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)	0.7877
NYMEX WTI ($US/bbl)	50.16
Light, Sweet Crude Oil at Edmonton ($C/bbl)	58.88
Bow River Crude Oil at Hardisty ($C/bbl)	46.58
Henry Hub NYMEX ($US/MMbtu)	2.58
AECO/NIT Spot ($C/MMbtu)	2.68
Edmonton Propane ($C/bbl)	7.03
Edmonton Butane ($C/bbl)	38.21

Average Realized Prices of Harvest Operations Corp.	
Light/Medium Oil ($/bbl)	49.59
Heavy Oil ($/bbl)	42.69
Natural Gas ($/Mcf)	2.62
Natural Gas Liquids ($/bbl)	29.36
Bitumen ($/bbl)	-

Average Realized Prices of Harvest's Equity Investment in Deep Basin Partnership	
Light/Medium Oil ($/bbl)	50.14
Natural Gas ($/Mcf)	2.69
Natural Gas Liquids ($/bbl)	38.08

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, 2016

Myron Hladyshevsky

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, 2015.

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-six 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

Myron Hladyshevsky