FORM 51-101F1
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

For the year ended December 31, 2013

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DEFINITIONS

In this Statement of Reserves Data and Other Oil and Gas Information, the following terms shall have the meanings set forth below, unless otherwise indicated. Certain terms are defined in National Instrument 51-101 ("NI 51-101") and the Canadian Securities Administrators ("CSA") Staff Notice 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA Staff Notice 51-324.

"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 $1.0 billion revolving credit facility, as amended, provided by a syndicate of lenders to Harvest as more fully described in the *"General Description of Capital Structure"* section in the Annual Information Form for the year ended December 31, 2013.

"Development Costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the reserves. More specifically, development costs including applicable operating costs of support equipment and facilities and other costs of development activities are costs incurred to:

a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

b) drill, complete and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and process plants, and central utility and waste disposal systems; and

d) provide improved recovery systems.

"Development Well" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"Exploration Costs" means costs incurred in identifying areas that may warrant examination, and in examining specific areas, that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometime referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies and salaries and other expenses of geologists, geophysical crew and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

b) costs of carrying and retaining unproved properties, such as lease rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records;

c) cry hole contributions and bottom hole contributions;

d) costs of drilling and equipping exploratory wells; and

e) costs of drilling exploratory type stratigraphic test wells.

"Exploratory Well" means a well that is not a developmental well, a service well or a stratigraphic test well.

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

"Forecast Prices and Costs" means future prices and costs that are:

a) generally accepted as being a reasonable outlook on the future and consistent with past experience and future trends,

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

"GAAP" means Generally Accepted Accounting Principles.

"GLJ" means GLJ Petroleum Consultants Ltd., independent oil and natural gas reserves evaluators of Calgary, Alberta.

"Gross" means:

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

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

(c) in relation to properties, the total area of properties in which Harvest has an interest.

"Harvest" means Harvest Operations Corp.

"Independent Qualified Reserves Evaluator" means GLJ, who evaluated the crude oil, natural gas liquids and natural gas reserves of Harvest as at December 31, 2013 in accordance with the standards contained in the COGE Handbook and the reserve definitions and other requirements contained in NI 51-101.

"KNOC" means Korea National Oil Corporation.

"McDaniel" means McDaniel & Associates Consultants Ltd., independent oil and natural gas reserves evaluators of Calgary, Alberta.

"Net" means:

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

(b) in relation to wells, the number of wells obtained by aggregating Harvest's Working Interest in each of its gross wells; and

(c) in relation to Harvest's interest in a property, the total area in which Harvest has an interest multiplied by the Working Interest owned by Harvest.

"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 one of them.

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and

- specified economic conditions.

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

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

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

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

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

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

   Developed Non-Producing Reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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

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

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

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

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

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

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

"Service Well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes; gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

"Stratigraphic test well" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration.

Stratigraphic test wells are classified as

a) "exploratory type", if not drilled into a proved property; or

b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"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 document, 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
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
Bcf	Billion cubic feet
EOR	Enhanced oil recovery
GJ	Gigajoule
H_2S	Hydrogen sulfide gas
mcf	Thousand cubic feet
MMbbls	Million barrels
MMboe	Million barrels of oil equivalent
MMcf	Million cubic feet
NGLs	Natural gas liquids
SAGD	Steam-assisted gravity drainage is an enhanced oil recovery technology for producing heavy crude oil and bitumen
WTI	West Texas Intermediate, the reference price in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
$ millions	Millions 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

ADVISORY

This Statement contains non-GAAP measures and forward-looking information about our current expectations, estimates and projections. Readers are cautioned that this Statement should be read in conjunction with the "Non-GAAP Measures" and "Special Note Regarding Forward-Looking Information" sections at the end of this Statement.

All dollar amounts set forth in this statement are in Canadian dollars, except where otherwise noted.

DATE OF STATEMENT

This Statement of Reserves Data and Other Oil and Gas Information (the "Statement") of Harvest is dated February 12, 2014. The effective date of the reserves and future net revenue information provided is December 31, 2013, unless otherwise indicated. The information contained herein was prepared on March 28, 2014.

DISCLOSURE OF RESERVES DATA

Harvest retained an Independent Qualified Reserves Evaluator to evaluate and prepare reports on 100% of Harvest's crude oil and natural gas reserves as of December 31, 2013. Harvest's reserves were evaluated by GLJ. All of Harvest's reserves were evaluated using the price and cost assumptions of GLJ as at January 1, 2014. Possible reserves were not evaluated, with the exception of contingent resources on the BlackGold oil sands project.

The reserves data and associated tables contained in this report summarize the reserves of crude oil, natural gas liquids and natural gas and the net present values of future net revenues associated with Harvest's reserves as evaluated in the report prepared by GLJ (the "Reserves Report"), based on forecast price assumptions presented in accordance with the standards contained in the COGE Handbook and the reserves definitions and other requirements contained in NI 51-101.

The tables presented herein summarize the data contained in the Reserves Report and as a result may contain slight rounding differences although they are substantively the same as the data in the Reserves Report. Totals may not add due to rounding.

All of Harvest's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan. This Statement is based on evaluations prepared by GLJ contained in their report dated February 12, 2014 with an effective date of December 31, 2013.

The future net revenue numbers presented throughout this Statement, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value of the reserves. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

There is no assurance that the forecast price and cost assumptions will be attained and variances could be material.

The following tables detail the aggregate gross and net reserves of the Corporation, at December 31, 2013, using forecast prices and costs as well the aggregate net present value ("NPV") of future net revenue attributable to the reserves estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20% (as noted in the introduction).

Summary of Oil & Gas Reserves
As of December 31, 2013
Forecast Prices and Costs

	Light and Medium Oil		Heavy Oil		Bitumen	
Reserves Category	Gross (MMbbls)	Net (MMbbls)	Gross (MMbbls)	Net (MMbbls)	Gross (MMbbls)	Net (MMbbls)
Proved						
Developed Producing	27.7	24.5	36.3	33.0	0.0	0.0
Developed Non-Producing	1.7	1.4	1.0	0.8	0.0	0.0
Undeveloped	1.7	1.5	7.2	5.8	96.0	85.0
Total Proved	**31.1**	**27.4**	**44.4**	**39.6**	**96.0**	**85.0**
Probable	14.3	12.5	20.3	17.6	163.4	131.9
Total Proved + Probable	**45.4**	**39.9**	**64.8**	**57.2**	**259.5**	**216.9**

	Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (Bcf)	Net (Bcf)	Gross (MMbbls)	Net (MMbbls)	Gross (MMboe)	Net (MMboe)
Proved						
Developed Producing	198.6	179.5	8.8	6.3	106.0	93.7
Developed Non-Producing	13.9	12.5	0.6	0.5	5.6	4.8
Undeveloped	73.1	64.8	3.3	2.7	120.4	105.8
Total Proved	**285.6**	**256.8**	**12.7**	**9.5**	**231.9**	**204.3**
Probable	139.5	123.9	9.9	7.4	231.2	190.0
Total Proved + Probable	**425.1**	**380.7**	**22.7**	**16.9**	**463.2**	**394.3**

Summary of Net Present Values of Future Net Revenue
As of December 31, 2013
Forecast Prices and Costs

Reserves Category	Before Income Taxes - Discounted at %/Year ($millions) 0%	5%	10%	15%	20%	NPV 10%/boe ($/boe)[1]
Proved						
Developed Producing	3,118	2,461	2,044	1,757	1,547	21.81
Developed Non-Producing	185	121	89	71	58	18.63
Undeveloped	2,243	1,208	737	481	325	6.97
Total Proved	5,546	3,790	2,870	2,309	1,930	14.05
Probable	5,785	2,668	1,423	839	530	7.49
Total Proved + Probable	11,331	6,458	4,293	3,148	2,460	10.89

(1) Unit values are based upon net reserves volumes.

Summary of Net Present Values of Future Net Revenue
As of December 31, 2013
Forecast Prices and Costs

Reserves Category	After Income Taxes Discounted at %/Year ($ millions) 0%	5%	10%	15%	20%
Proved					
Developed Producing	2,947	2,348	1,967	1,703	1,508
Developed Non-Producing	144	93	69	55	46
Undeveloped	1,935	1,058	648	421	280
Total Proved	5,026	3,499	2,684	2,179	1,834
Probable	4,314	1,943	1,006	571	343
Total Proved + Probable	9,340	5,442	3,691	2,750	2,177

The following tables provide (i) a breakdown of various elements of undiscounted future net revenue attributable to proved reserves and proved plus probable reserves of the Corporation, and (ii) the future net revenue by production group in each reserves category:

Total Future Net Revenue (undiscounted)
As of December 31, 2013
Forecast Prices and Costs ($ millions)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved	15,954	1,975	6,335	1,928	170	5,546	521	5,026
Proved + Probable	33,828	5,200	11,653	5,391	253	11,331	1,992	9,340

Future Net Revenue by Production Group
As of December 31, 2013
Forecast Prices and Costs

Reserves Category	Production Group	Before Income Taxes (discounted at 10%/year) $ millions	Unit Value[3]
Proved Reserves	**Conventional Reserves**		
	Light and Medium Crude Oil[1]	745	$25.38/bbl
	Heavy Crude Oil[1]	965	$22.86/bbl
	Associated and Non-Associated Natural Gas[2]	597	$2.11/mcf
	Non-Conventional Reserves		
	Bitumen	558	$6.56/bbl
	Coal bed methane	7	$1.75/mcf
	Total	**2,870**	**$14.05/boe**
Proved + Probable Reserves	**Conventional Reserves**		
	Light and Medium Crude Oil[1]	935	$21.85/bbl
	Heavy Crude Oil[1]	1,321	$21.60/bbl
	Associated and Non-Associated Natural Gas[2]	872	$2.00/mcf
	Non-Conventional Reserves		
	Bitumen	1,157	$5.33/bbl
	Coal bed methane	9	$1.65/mcf
	Total	**4,293**	**$10.89/boe**

(1) Includes solution gas and associated by-products
(2) Includes associated by-products
(3) Unit values are based upon net reserves volumes

PRICING ASSUMPTIONS

The forecast costs and prices assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. A complete listing of the forecast is available on GLJ's website at: https://www.gljpc.com/commodity-price-forecasts. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the Reserves Report, based on the GLJ January 1, 2014 price forecast, are as follows:

Summary of Pricing and Inflation Rate Assumptions
as of January 1, 2014
Forecast Prices and Costs

	OIL					NATURAL GAS	Natural Gas Liquids				INFLATION RATES (6)	U.S./ CAN EXCHANGE RATE (7)
	WTI Crude Oil (1)	Edmonton Light Crude Oil (2)	Alberta Heavy Crude Oil (3)	Alberta Bow River Hardisty Crude Oil (4)	Sask Cromer Medium Crude Oil (5)	Alberta AECO Spot Price	Spec Ethane	Edmonton Propane	Edmonton Butane	Edmonton Pentanes +		
Year	($US/ bbl)	($Cdn/ bbl)	($Cdn/ bbl)	($Cdn/ bbl)	($Cdn/ bbl)	($Cdn/ GJ)	CAD/bbl	CAD/bbl	CAD/bbl	CAD/bbl	(%/Year)	($US/$Cdn)
2014	97.50	92.76	65.72	77.46	86.27	4.03	13.26	57.83	73.22	105.20	2.0	0.950
2015	97.50	97.37	70.03	81.30	90.55	4.26	14.08	58.42	75.95	107.11	2.0	0.950
2016	97.50	100.00	72.85	83.50	93.00	4.50	14.89	60.00	78.00	107.00	2.0	0.950
2017	97.50	100.00	72.85	83.50	93.00	4.74	15.71	60.00	78.00	107.00	2.0	0.950
2018	97.50	100.00	72.85	83.50	93.00	4.97	16.53	60.00	78.00	107.00	2.0	0.950
2019	97.50	100.00	72.85	83.50	93.00	5.21	17.34	60.00	78.00	107.00	2.0	0.950
2020	98.54	100.77	73.42	84.14	93.71	5.33	17.77	60.46	78.60	107.82	2.0	0.950
2021	100.51	102.78	74.90	85.82	95.58	5.44	18.13	61.67	80.17	109.97	2.0	0.950
2022	102.52	104.83	76.42	87.53	97.49	5.55	18.52	62.90	81.77	112.17	2.0	0.950
2023	104.57	106.93	77.97	89.28	99.44	5.66	18.88	64.16	83.40	114.41	2.0	0.950
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.950

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

Weighted average historical prices prior to hedging realized by Harvest and Operating Subsidiaries for the year ended December 31, 2013, were $3.46/mcf for natural gas, $57.44/bbl for natural gas liquids, $85.38/bbl for light/medium oil, and $74.37/bbl for heavy oil.

RECONCILIATION OF CHANGES IN RESERVES

Reconciliation

By Principal Product Type

Forecast Prices and Cost

	Light and Medium Oil			Heavy Oil			Bitumen		
FACTORS	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)
31-Dec-12(1)	**40.1**	**18.7**	**58.8**	**50.5**	**22.8**	**73.2**	**94.1**	**165.1**	**259.2**
Extensions/Improved Recovery	1.7	(0.1)	1.5	3.5	2.0	5.5	-	-	-
Technical Revisions	(1.9)	(3.2)	(5.2)	(2.6)	(4.2)	(6.8)	1.9	(1.7)	0.2
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	0.5	0.1	0.6	-	-	-	-	-	-
Dispositions	(4.9)	(1.2)	(6.0)	(0.8)	(0.2)	(1.0)	-	-	-
Production(2)	(4.3)	-	(4.3)	(6.2)	-	(6.2)	-	-	-
31-Dec-13	**31.1**	**14.3**	**45.4**	**44.4**	**20.3**	**64.8**	**96.0**	**163.4**	**259.5**

	Associated and Non-Associated Natural Gas(3)			Natural Gas Liquids			Total (boe)		
FACTORS	Gross Proved (Bcf)	Gross Probable (Bcf)	Gross Proved Plus Probable (Bcf)	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Proved (MMboe)	Gross Probable (MMboe)	Gross Proved Plus Probable (MMboe)
31-Dec-12(1)	**316.1**	**153.9**	**470.0**	**15.0**	**9.3**	**24.3**	**252.3**	**241.5**	**493.8**
Extensions/Improved Recovery	13.3	(4.4)	8.9	0.7	0.2	0.8	8.1	1.3	9.3
Technical Revisions	12.4	(4.2)	8.2	(0.7)	0.6	(0.2)	(1.2)	(9.3)	(10.5)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	1.0	0.5	1.5	0.1	-	0.1	0.7	0.2	0.9
Dispositions	(17.6)	(6.2)	(23.8)	(0.3)	(0.1)	(0.5)	(8.9)	(2.5)	(11.4)
Production(2)	(39.8)	-	(39.8)	(1.9)	-	(1.9)	(19.0)	-	(19.0)
31-Dec-13	**285.6**	**139.5**	**425.1**	**12.7**	**9.9**	**22.7**	**231.9**	**231.2**	**463.2**

(1) Opening balance values include the sum of GLJ and McDaniel evaluations at December 31, 2012.

(2) The stated 2013 production of 19.0 mmboe in this table does not line up with the actual recorded production of 19.2 mmboe for Harvest in 2013 since the Independent Qualified Reserves Evaluator's report was prepared before 2013 actual production was available and therefore their report reflects estimates for 2013 production.

(3) Coal bed methane of 2.1 Bcf proved and 3.0 Bcf proved plus probable have been included with natural gas.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. As at January 1, 2014, Harvest has a total of 126 MMboe of gross reserves that are classified as proved non-producing. Of these non-producing reserves, approximately 96% are undeveloped reserves. The balance are developed non-producing reserves which would be wells that were not producing as of December 31, 2013 and are eligible to be brought on production given economics and production information as at January 1, 2014.

Gross Reserves First Attributed by Year(1)

	Proved Undeveloped											
	Light and Medium Crude Oil (MMbbl)		Heavy Crude Oil (MMbbl)		Natural Gas (Bcf)		Natural Gas Liquids (MMbbl)		Bitumen (MMbbl)		Total Oil Equivalent (MMboe)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior	11.2	11.2	3.8	3.8	27.0	27.0	0.6	0.6	93.6	93.6	113.6	113.6
2011	0.6	9.6	1.3	3.2	40.6	62.4	1.5	2.0	–	93.6	10.2	118.8
2012	0.3	3.4	0.3	7.2	14.0	82.6	1.0	4.0	–	94.1	3.9	122.4
2013	1.1	1.7	2.6	7.2	10.3	73.1	0.4	3.3	–	96.0	5.8	120.4

	Probable Undeveloped											
	Light and Medium Crude Oil (MMbbl)		Heavy Crude Oil (MMbbl)		Natural Gas (Bcf)		Natural Gas Liquids (MMbbl)		Bitumen (MMbbl)		Total Oil Equivalent (MMboe)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior	9.2	9.2	8.2	8.2	25.5	25.5	0.9	0.9	165.6	165.6	188.2	188.2
2011	1.0	9.4	0.6	8.2	34.6	52.4	2.7	3.3	–	165.6	10.0	195.3
2012	0.5	9.0	0.3	8.8	21.2	73.5	1.6	5.6	–	165.1	5.9	200.9
2013	2.4	6.5	1.8	8.0	6.8	68.0	0.6	6.5	–	163.4	5.9	195.7

(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

Substantially all of Harvest's undeveloped reserves are based on Harvest's 2013 budget and long range development plans for the major assets noted elsewhere in this document. Excluding BlackGold's bitumen reserves, approximately 23% of these reserves are expected to be developed within the next two years (pending product pricing and capital availability). The remaining 77% of undeveloped reserves, excluding BlackGold, are expected to be developed over the next five years. The development schedule of Harvest's undeveloped reserves is linked to processing facility capacity restrictions and capital allocation plans. The capital cost has been taken into account for these programs in the estimated future net revenue.

BlackGold Bitumen

Approximately 80% and 84% of Harvest's proved undeveloped and probable undeveloped reserves, respectively, are located on Harvest's BlackGold oil sands property. At the end of 2013, Harvest's BlackGold oil sands project had proved undeveloped bitumen reserves of 96.0 MMbbl and probable undeveloped bitumen reserves of 163.4 MMbbl. The evaluation of these reserves anticipates they will be recovered using SAGD technologies.

The BlackGold project requires the construction of steam generation, gathering systems and central processing facilities that service and support SAGD well pairs. The central processing facility is designed for 25 years of useful life (with up to approximately 35 to 40 years of useful life based on adequate maintenance) while the SAGD well pairs are designed to have individual useful lives of 7 – 9 years on a declining basis. Therefore, to build a central facility that would process the entire field simultaneously would be neither economic nor environmentally efficient. Due to the high capital and operating costs associated with SAGD production, greater economic value and environmental efficiency are achieved by building a central facility with optimal capacity that provides for a series of SAGD well pairs to be drilled and produced over the life of the central processing facility. As the central processing facility has a long life relative to well pairs, in the early stages of a SAGD project, only a small portion of proved reserves will be developed as the number of well pairs drilled will be limited by the available steam and processing capacity. The undeveloped reserves assigned to BlackGold are forecast to be developed over the next 25 years; however the timing of the conversion of those reserves from undeveloped to developed will depend on when the well pair targeting those reserves is scheduled during the life of the central processing facility and steam generator. Development of the proved undeveloped reserves will take place in an orderly manner as additional well pairs are drilled to utilize the available steam and processing capacity when existing well pairs reach the end of their steam injection phase and when they reach production decline.

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

Significant Factors or Uncertainties Affecting Reserves Data

The evaluation of reserves is a continuous process, one that can be significantly impacted by a variety of internal and external influences. Revisions are often required resulting from changes in pricing, economic conditions, regulatory changes, and historical performance. While these factors can be considered and potentially anticipated, certain judgments and assumptions are always required. As new information becomes available these areas are reviewed and revised accordingly. For a discussion of risk factors and uncertainties affecting reserves data, see *Risk Factors – Risks Associated with Reserve Estimates* in the Annual Information Form for the year ended December 31, 2013.

Future Development Costs

The following table sets forth development costs deducted in the estimation of Harvest's future net revenue attributable to the reserves categories noted below:

	Forecast Prices and Costs ($ Millions)	
Year	Proved Reserves	Proved Plus Probable Reserves
2014	240	341
2015	235	398
2016	104	194
2017	62	333
2018	19	553
Thereafter	1,268	3,572
Total Undiscounted	**1,928**	**5,391**
Total Discounted at 10%	841	2,141

Future development costs are based on a number of factors and assumptions made at a point in time. Actual future development costs could differ materially depending on numerous factors, such as but not limited to changes in supply and demand of crude oil and natural gas, commodity prices, availability and cost of labor, material and equipment, changes in regulatory environment and commercial negotiation. Future development costs will be funded through a combination of cash flow from operating activities, proceeds from dispositions, borrowings under the Credit Facility, long-term debt issuances and or capital injections from KNOC. Please refer to the "Liquidity" section in the Management Discussion and Analysis and "Risk Factors" section of the Annual Information Form for the year ended December 31, 2013 for discussions on the risks and uncertainties around availability of future capital resources.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenue to certain extent depending on the source of funding used and the cost of funding at the time. The Corporation does not expect that interest or other funding costs would materially impact future net revenue, reserves or future development decision though this is subject to some degree of uncertainty. See "Risk Factors" section of the Annual Information Form for the year ended December 31, 2013 for further discussion.

Estimated future downhole costs related to a property have been taken into account by the Independent Qualified Reserves Evaluator in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom. No allowance was made, however, for reclamation of well sites or the abandonment and reclamation of any facilities. See *Additional Information Concerning Abandonment and Reclamation Costs* in this statement for more information.

OTHER OIL AND GAS INFORMATION

Oil and Natural Gas Properties

Harvest and Operating Subsidiaries' portfolio of significant properties are aggregated into material areas and discussed below.

In general, the properties include major oil accumulations which benefit from active pressure support due to an underlying regional aquifer. Generally, the properties have predictable decline rates with costs of production and oil price key to determining the economic limits of production. Harvest is actively engaged in cost reduction, production and reserves replacement optimization efforts directed at reserves addition through extending the economic life of these producing properties beyond the limits used in the Reserves Report and developing new proven reserves previously not evaluated by the Independent Qualified 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.

Principal Producing Properties at December 31, 2013

Hay River

Hay River was acquired by Harvest on August 2, 2005 and is located approximately 125 miles north west of Grande Prairie in north-eastern British Columbia. In 2013, Hay River produced 5,237 boe/day of 24^{o} API crude oil (including a trace – 23 barrels per day of condensate and a 235 mcf per day of solution gas) from the Bluesky formation located at a depth of approximately 350 metres. Natural gas produced from this formation, along with produced water, were re-injected for pressure support. Produced emulsion is processed at the central emulsion processing facility with the clean oil transported via pipeline to sales points.

Hay River is a winter-only access area in that drilling operations can only be reasonably undertaken when the ground is frozen (typically between late November and mid-March). The Hay River medium gravity oil production is priced at a discount to the Edmonton Light oil benchmark, contributing to stronger netbacks when compared to other similar gravity crudes. Harvest has a 100% Working Interest in this operated property. In 2013, Harvest drilled 28 gross 100% Working Interest wells, including 16 horizontal producing wells, and 9 water injection wells and established new infrastructure with a total capital expenditure of $63 million.

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

Red Earth

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

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

West Central Alberta

West Central Alberta is comprised of properties west of Highway 2, south of Edmonton and north of Calgary. This is primarily a liquids-rich natural gas producing area for the Corporation with some oil production. Properties for this area were added through acquisition over the last several years with the most recent major acquisition being

Hunt Oil Company of Canada, Inc.'s and Hunt Oil Alberta Inc.'s (collectively, "Hunt") assets in 2011. Production in 2013 for the region averaged 14,489 boe/d (60% gas).

Major fields in this area include Caroline (Beaverhill Lake liquids rich 50% H_2S gas), Crossfield (Ellerslie oil and Basal Quartz gas), Markerville (Pekisko, Edmonton Sands, Cardium and Glauconite and Ellerslie) and Rimbey (Glauconite, Ostracod, Notikewin and Cardium). All new liquids-rich gas production and oil production are from stage stimulated horizontal wells except for a highly prolific vertical gas play in the Glauconite.

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

East Central Alberta

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

Deep Basin

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

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

Heavy Oil

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

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

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

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

Saskatchewan Light Oil

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

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

BlackGold

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

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

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

Oil and Gas Wells

The following table sets forth the number of oil and gas wells in which Harvest held a Working Interest at December 31, 2013:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing[1]		Producing		Non-Producing[1]	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	2,969	2,243	1,203	893	1,710	536	840	320
British Columbia	554	394	143	69	64	13	96	46
Saskatchewan	500	448	526	436	6	1	53	44
Total	4,023	3,085	1,872	1,398	1,780	550	989	410

(1) Non-producing wells include wells which are capable of producing, but which are currently not producing. Non-producing wells do not include other types of wells such as service wells or wells that have been abandoned.

Properties with No Attributed Reserves

The following tables set out Harvest's undeveloped land holdings as at December 31, 2013:

	Undeveloped Land (Hectares)[1]	
	Gross	Net
Alberta	278,820	202,410
British Columbia	96,553	57,919
Saskatchewan	18,959	15,455
Total	394,332	275,784

	Undeveloped Hectares with Rights[1] Expiring Within One Year	
	Gross	Net
Alberta	19,314	17,529
British Columbia	9,624	6,957
Saskatchewan	6,712	3,595
Total	35,650	28,081

(1) For areas where Harvest holds interests in different formations under the same surface area through separate leases, the gross and net hectares are calculated on the individual lease basis.

Harvest conducts ongoing development activity to retain land that would otherwise expire. As a result of this activity, the actual land holdings that will expire within one year may be less than indicated above.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

Harvest has land holdings with no attributed reserves for future exploration and development that are pending the geoscience and engineering analysis to identify and evaluate future prospects. These exploration and development activities are pending the availability of future capital.

Additional Information Concerning Abandonment and Reclamation Costs

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

Period	Abandonment & Reclamation Costs (undiscounted and inflated at 1.7%) ($millions)	Abandonment & Reclamation Costs (discounted at 10% and inflated at 1.7%) ($millions)
Total as at December 31, 2013	1,525.1	283.0
Anticipated to be paid in 2014	35.6	32.3
Anticipated to be paid in 2015	29.6	24.5
Anticipated to be paid in 2016	31.1	23.4

Harvest estimates the costs to abandon and reclaim all of its shut-in and producing wells, pipelines and facilities. Harvest’s model for estimating the amount and timing of future abandonment and reclamation expenditures was created on an operating area level. Estimated expenditures are based on the Alberta Energy Regulator (“AER”) methodology from 2013 which details the cost of abandonment and reclamation costs in eight specific geographic regions, coupled with our own experience on actual abandonment costs in each region.

Each region was assigned an average cost per well to abandon and reclaim the wells in that area. The cumulative yearly costs that will be incurred for producing wells are based on the reserve lives of each area provided by the Independent Qualified Reserves Evaluator. The cumulative yearly costs that will be incurred for suspended wells are based on AER Directive 13 and Directive 20 guidelines. Facility abandonment and reclamation costs are scheduled to be incurred in the year following the end of the reserves life of its associated reserves. Abandonment and reclamation costs have been estimated over a 60-year period.

Harvest expects to incur abandonment and reclamation costs in respect of 6,646 net wells at December 31, 2013.

Abandonment costs (excluding salvage values) associated with wells to which reserves were attributed, were deducted by the Independent Reserves Evaluator in estimating future net revenue and value in the Reserves Reports. The estimated future undiscounted expense related to wells, facilities and pipelines, which were not deducted by the Independent Qualified Reserves Evaluator, are $1,272.1 million ($222.0 million discounted at 10%). The nature of these expenses are not expected to change the anticipated costs for the next three years, as they will not be incurred until the end of a field's reserves life profile.

Tax Horizon

Harvest anticipates that there will be no cash income tax payable prior to 2028. However, this estimate is highly sensitive to variables such as commodity prices, production and the timing of future capital spending. If commodity prices were to strengthen beyond the levels anticipated by the forward market, our tax pools would be utilized more quickly and the Corporation may be required to pay cash income taxes sooner than anticipated.

Costs Incurred

The following table summarizes capital expenditures (net of incentives and net of certain proceeds, including capitalized general and administrative expenses) related to Upstream activities for the year ended December 31, 2013:

($ millions)	Oil & Gas Capital Expenditures (Excluding Oil Sands)	Oil Sands Capital Expenditures	Total Capital Expenditures[(1)]
Property acquisition costs			
Proved properties	12.9	0.7	13.6
Unproved properties	-	-	-
Total property acquisition	12.9	0.7	13.6
Exploration costs	16.7	-	16.7
Development costs	301.0	382.5	683.5
Total	330.6	383.2	713.8

(1) Total capital expenditures exclude costs related to corporate assets of $4.7 million.

Exploration and Development Activities

The following table sets forth the number of Exploratory and Development Wells completed during 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

2014 Capital Expenditure Plan

Harvest's expected total capital spending on its oil and natural gas properties for 2014 is expected to be approximately $500 million. The primary areas of focus for Harvest's Upstream and BlackGold capital program during 2014 are the following:

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

Incremental Exploitation and Development Potential

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

- Implementation or optimization of enhanced water floods beyond the two polymer floods previously mentioned in selected pools such as Suffield, Hay River, Red Earth, Cecil and Kindersley resulting in increased production and recovery;
- Increasing water handling and water disposal capacity at key fields such as Hayter, Suffield and Bellshill Lake to add incremental oil volumes. This includes additional use of free water knock-outs and additional disposal wells;
- De-bottlenecking existing fluid handling facilities and surface infrastructure;
- Uphole completions of bypassed or untested reserves in existing wellbores, including recompletion of existing shut-in wells to access undrained reserves;

- Selected infill and step-out development drilling opportunities for various proven targets generally defined by 3-D seismic;
- Numerous exploratory opportunities defined by seismic from which value might be extracted by sale, Farmout or joint venture;
- Management of dry gas portfolio to shut-in wells currently with low gas netbacks due to falling gas prices to preserve reserves to be produced at a time when gas prices improve; and
- Utilizing multistage fractured technology in horizontal wells to increase oil recovery from tight oil and gas formations at Red Earth (Slave Point Formation), Crossfield (Basal Quartz and Ellerslie Formations), Kindersley (Viking Formation), Deep Basin (Falher Formation) and Rimbey/West Central Area (Cardium, Glauconite, Viking, Ostracod, Notikewin, Wilrich Formations).

Production Estimates

The following table sets forth the forecast volume of production from Harvest's gross reserves estimated from the 2013 year-end Reserves Report:

2014 Production Forecast Before Royalty Interests

	Light and Medium Oil bbl/d	Heavy Oil bbl/d	Bitumen bbl/d	Natural Gas mcf/d	Natural Gas Liquids bbl/d	Total[(1)] boe/d
Proved Producing	10,946	14,899	–	89,676	4,380	45,172
Proved Developed Non-Producing	133	196	–	3,237	259	1,128
Proved Undeveloped	247	1,838	885	6,212	428	4,434
Total Proved	11,327	16,933	885	99,125	5,068	50,733
Total Probable	972	1,439	115	9,831	740	4,905
Total Proved Plus Probable	12,299	18,372	1,000	108,956	5,808	55,638

(1) No individual field accounts for more than 20% of Harvest's total 2014 production forecast.

Production History

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

Average Daily Production Volumes

	2013 Q1	Q2	Q3	Q4	Total
Light & Medium Oil (bbl/d)	13,217	11,837	10,844	10,820	11,671
Heavy Oil (bbl/d)	17,227	17,455	16,604	16,348	16,905
Total Oil (bbl/d)	30,444	29,292	27,448	27,168	28,576
NGLs (bbl/d)	5,953	5,510	5,324	4,607	5,345
Natural Gas(mcf/d)	115,050	111,954	114,066	104,269	111,313
Total Daily Production (boe/d)	55,571	53,461	51,783	49,154	52,473

Total Sales Production

	2013 Q1	Q2	Q3	Q4	Total
Light and Medium Oil (MMbbl)	1.2	1.1	1.0	1.0	4.3
Heavy Oil (MMbbl)	1.6	1.6	1.5	1.5	6.2
Total Oil (MMbbl)	2.8	2.7	2.5	2.5	10.5
NGLs (MMbbl)	0.5	0.5	0.5	0.4	1.9
Natural Gas (Bcf)	10.4	10.2	10.5	9.6	40.7
Total Production (MMboe)	5.0	4.9	4.8	4.5	19.2

Average Sales Prices Received

	2013				
	Q1	Q2	Q3	Q4	Total
Light & Medium oil ($/bbl)	80.14	85.90	96.75	79.67	85.38
Heavy Oil ($/bbl) [1]	64.38	76.55	88.47	68.03	74.37
Total Oil ($/bbl)	71.22	80.33	91.74	72.67	78.86
NGLs ($/bbl)	60.16	53.48	57.20	58.97	57.44
Natural Gas ($/mcf) [1]	3.46	3.83	2.72	3.86	3.46
Total ($/boe)	53.43	58.22	60.62	54.01	56.58

Royalties Paid

	2013				
	Q1	Q2	Q3	Q4	Total
($ millions)					
Light & Medium Oil	13.4	13.4	16.2	14.7	57.7
Heavy Oil	13.7	20.1	21.7	17.7	73.2
NGLs	3.7	4.9	2.7	3.4	14.7
Natural gas	1.9	3.2	1.5	1.7	8.3
Total	32.7	41.6	42.1	37.5	153.9
Light & Medium Oil ($/bbl)	11.26	12.44	16.24	14.77	13.42
Heavy Oil ($/bbl)	8.74	12.65	14.21	11.77	11.81
NGLs (S/bbl)	6.91	9.77	5.51	8.02	7.74
Natural gas ($/boe)	1.10	1.88	0.86	1.06	1.22
Total ($/boe)	6.54	8.55	8.84	8.29	8.04

Operating Expenses

	2013				
	Q1	Q2	Q3	Q4	Total
($ millions)					
Light & Medium Oil	29.8	28.3	27.4	23.7	109.2
Heavy Oil	36.3	33.3	31.9	32.8	134.3
NGLs	6.9	6.9	6.4	6.1	26.3
Natural gas	18.7	18.4	19.0	19.7	75.8
Total	91.7	86.9	84.7	82.3	345.6
Light & Medium Oil ($/bbl)	25.05	26.27	27.46	23.81	25.40
Heavy Oil ($/bbl)	23.16	20.97	20.88	21.81	21.66
NGLs ($/boe)	12.88	13.76	13.07	14.39	13.84
Natural Gas ($/boe)	10.84	10.84	10.86	12.32	11.17
Total ($/boe)	18.32	17.85	17.78	18.20	18.05

Netback Received[(2)(3)]

	2013				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($/bbl)	43.83	47.19	53.05	41.09	46.56
Heavy Oil ($/bbl) [(1)]	32.48	42.93	53.38	34.45	40.90
NGLs ($/bbl)	40.37	29.95	38.62	36.56	35.86
Natural Gas ($/boe) [(1)]	8.82	10.26	4.60	9.78	8.37
Total ($/boe)	28.57	31.82	34.00	27.52	30.49

(1) Before gains or losses on risk management contracts.
(2) Netbacks are calculated by subtracting royalties and operating expenses before gains or losses on risk management contracts and transportation expenses.
(3) These are non-GAAP measures. Please refer to "Non-GAAP Measures" section.

2013 Historical Production by Material Area

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

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

All forward-looking statements in this document and in certain documents incorporated by reference herein, are based on assumptions and the Corporation's (as defined below) view of future events which reflect information available at the time the assumption was made. Certain statements contained in this document constitute forward-looking statements. The use of any of the words "budget", "outlook", "seek", "plan", "project", "predict", "potential", "intend", "anticipate", "continue", "estimate", "expect", "may", "will", "assume", "should", "could", "might", "believe", "target", "forecast" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Management of the Corporation believes the expectations reflected in those 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 herein should not be unduly relied upon. These statements speak only as of the date hereof or at the date specified in the documents incorporated by reference into this document.

In particular, this document contains forward-looking statements pertaining to the following:

- oil and natural gas production levels;
- capital expenditure programs and related spending;
- factors upon which to decide whether or not to undertake a capital project;
- possible commerciality of capital projects;
- the quantity and net future revenues of the oil and natural gas reserves;
- projections of commodity prices and costs;
- future cash flows from reserves;
- supply and demand for oil and natural gas;

- expectations regarding the ability to raise capital and continually add reserves through exploration, development and acquisitions; and
- treatment under governmental regulatory regimes including but not limited to royalties, environmental and taxation.

With respect to forward-looking statements contained in this Form, 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 continued availability of adequate cash flow and debt and/or equity financing to fund Harvest's capital and operating requirements as needed;
- Harvest's ability to obtain financing with favorable terms;
- the general continuance of current or, where applicable, assumed industry conditions;
- the general continuation of assumed tax, royalty and regulatory regimes;
- the accuracy of the Corporation's reserves;
- the ability to obtain equipment in a timely manner to carry out development and other capital activities;
- the ability to market oil and natural gas successfully to current and new customers;
- the cost of expanding Harvest's property holdings;
- the impact of increasing competition; and
- the ability to add production and reserves through development and exploitation activities.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this document:

- volatility in market prices for oil and natural gas;
- determination of global economy;
- adverse changes to law and regulations;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility; and
- failure to realize the anticipated benefits of acquisitions.

Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this document or otherwise. Reader should also carefully consider the matters discussed under the heading "Forward-Looking Statements" and "Risk Factors" in the Annual Information Form for the year ended December 31, 2013.

NON-GAAP MEASURES

Throughout this document, Harvest has referred to certain measures of financial performance that are not specifically defined under GAAP such as "Netbacks".

"Netbacks" are reported on a per boe basis and used extensively in the Canadian energy sector for comparative purposes. "Netbacks" include revenues, royalties and operating expenses, and realized gains or losses on risk management contracts. 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.

FORM 51-101F2: REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the board of directors of Harvest Operations Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deductions of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs, and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013 and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and board of directors:

			Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate)($ millions)			
	Description and Preparation Date of Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	BlackGold February 10, 2014	Canada	-	1,156	-	1,156
GLJ Petroleum Consultants Ltd.	February 10, 2014	Canada	-	3,137	-	3,137
Totals			-	4,293	-	4,293

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed by did not audit or evaluate.

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

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

Executed as to our reports referred to above:

(Signed) "Myron J. Hladyshevsky", P. Eng.

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

February 12, 2014

FORM 51-101F3: REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Harvest Operations Corp. (the “Corporation”) is responsible for the preparation and disclosure of information with respect to the Corporation’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

Independent qualified reserves evaluator has evaluated the Corporation’s reserves data. The report of the independent qualified reserves evaluator is presented above in Form 51-101F2.

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

(a) reviewed the Corporation’s procedures for providing information to the independent qualified reserves evaluator;

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

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

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

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

(Signed)
Myunghuhn Yi
President & CEO

(Signed)
YS Kim
Deputy Chief Operating Officer

(Signed)
Allan Buchignani
Director

(Signed)
Richard Kines
Director

March 28, 2014