Harvest OPERATIONS CORP.

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

For the year ended December 31, 2012

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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 $800 million 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, 2012.

"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 Evaluators" means McDaniel and GLJ, who evaluated the crude oil, natural gas liquids and natural gas reserves of Harvest as at December 31, 2012 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
H2S	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 March 28, 2013. The effective date of the reserves and future net revenue information provided is December 31, 2012, unless otherwise indicated. The information contained herein was prepared on March 28, 2013.

DISCLOSURE OF RESERVES DATA

Harvest retained Independent Qualified Reserves Evaluators to evaluate and prepare reports on 100% of Harvest's crude oil and natural gas reserves as of December 31, 2012. Harvest's reserves were evaluated by McDaniel who evaluated approximately 15% of Harvest's total proved plus probable reserves, and GLJ who evaluated approximately 85% of Harvest's total proved plus probable reserves. All of Harvest's reserves were evaluated using the price and cost assumptions of McDaniel as at January 1, 2013. Possible reserves were not evaluated, with the exception of contingent resources on our 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 reports prepared by McDaniel and GLJ (the "Reserves Reports"), 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 combined data contained in the two Reserves Reports and as a result may contain slight rounding differences although they are substantively the same as the data in the Reserves Reports.

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 and McDaniel contained in their reports dated February 13, 2013 and February 27, 2013, respectively, both with an effective date of December 31, 2012.

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, 2012, 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).

Totals may not match exactly due to rounding.

Summary of Oil & Gas Reserves
As of December 31, 2012
Forecast Prices and Costs

	Light and Medium Oil		Heavy Oil		Bitumen	
	Gross	Net	Gross	Net	Gross	Net
Reserves Category	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)
Proved						
Developed Producing	34.8	30.6	42.0	37.6	-	-
Developed Non-Producing	1.9	1.7	1.3	1.1	-	-
Undeveloped	3.4	3.0	7.2	5.8	94.1	79.3
Total Proved	**40.1**	**35.3**	**50.5**	**44.5**	**94.1**	**79.3**
Probable	18.7	16.1	22.8	19.3	165.1	129.0
Total Proved + Probable	**58.8**	**51.4**	**73.2**	**63.8**	**259.2**	**208.3**

	Natural Gas(1)		Natural Gas Liquids		Total Oil Equivalent	
	Gross	Net	Gross	Net	Gross	Net
Reserves Category	(Bcf)	(Bcf)	(MMbbls)	(MMbbls)	(MMboe)	(MMboe)
Proved						
Developed Producing	220.2	197.8	10.6	7.7	124.0	108.9
Developed Non-Producing	13.3	11.9	0.4	0.3	5.9	5.0
Undeveloped	82.6	74.4	4.0	3.3	122.4	103.8
Total Proved	**316.1**	**284.2**	**15.0**	**11.3**	**252.3**	**217.8**
Probable	153.9	136.3	9.3	6.9	241.5	194.0
Total Proved + Probable	**470.0**	**420.5**	**24.3**	**18.3**	**493.8**	**411.8**

(1) Coal bed methane of 1.5 Bcf proved and 2.2 Bcf proved plus probable have been included with natural gas.

Summary of Net Present Values of Future Net Revenue
As of December 31, 2012
Forecast Prices and Costs

	Before Income Taxes - Discounted at %/Year ($millions)					NPV 10%/boe
Reserves Category	0%	5%	10%	15%	20%	($/boe)[1]
Proved						
Developed Producing	3,764	2,918	2,396	2,043	1,789	21.99
Developed Non-Producing	204	116	80	60	47	15.86
Undeveloped	2,659	1,276	653	325	132	6.29
Total Proved	**6,627**	**4,310**	**3,128**	**2,428**	**1,968**	**14.37**
Probable	7,234	3,407	1,841	1,090	684	9.49
Total Proved + Probable	**13,861**	**7,717**	**4,969**	**3,518**	**2,652**	**12.07**

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

Summary of Net Present Values of Future Net Revenue
As of December 31, 2012
Forecast Prices and Costs

	After Income Taxes Discounted at %/Year ($ millions)				
Reserves Category	0%	5%	10%	15%	20%
Proved					
Developed Producing	3,539	2,746	2,257	1,927	1,688
Developed Non-Producing	156	98	74	60	50
Undeveloped	2,155	1,048	541	268	104
Total Proved	**5,850**	**3,892**	**2,872**	**2,254**	**1,842**
Probable	5,397	2,496	1,316	753	450
Total Proved + Probable	**11,247**	**6,388**	**4,187**	**3,007**	**2,292**

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, 2012
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	18,329	2,604	6,745	2,127	227	6,627	777	5,850
Proved + Probable	38,285	6,575	12,412	5,130	306	13,861	2,614	11,247

Future Net Revenue by Production Group
As of December 31, 2012
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]	889	$22.96/bbl
	Heavy Crude Oil[1]	1,166	$25.39/bbl
	Associated and Non-Associated Natural Gas[2]	611	$11.69/mcf
	Non-Conventional Reserves		
	Bitumen	461	$5.81/bbl
	Coal bed methane	1	$1.01/mcf
	Total	**3,128**	**$14.37/boe**
Proved + Probable Reserves	**Conventional Reserves**		
	Light and Medium Crude Oil[1]	1,168	$20.44/bbl
	Heavy Crude Oil[1]	1,572	$23.77/bbl
	Associated and Non-Associated Natural Gas[2]	870	$11.78/mcf
	Non-Conventional Reserves		
	Bitumen	1,358	$6.52/bbl
	Coal bed methane	2	$0.38/mcf
	Total	**4,969**	**$12.07/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 McDaniel's website at: http://www.mcdan.com/pricing_forecasts.html. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the Reserves Report, based on the McDaniel January 1, 2013 price forecast, are as follows:

Summary of Pricing and Inflation Rate Assumptions
as of January 1, 2013
Forecast Prices and Costs

Year	WTI Crude Oil[1] $US/ bbl	Oil: Edmonton Light Crude Oil[2] $Cdn/ bbl	Alberta Heavy Crude Oil[3] $Cdn/ bbl	Alberta Bow River Hardisty Crude Oil[4] $Cdn/ bbl	Sask Cromer Medium Crude Oil[5] $Cdn/ bbl	Natural Gas: Alberta AECO Spot Price $Cdn/ GJ	Natural Gas Liquids: Edmonton Cond. and Natural Gasolines $Cdn/ bbl	Inflation Rates[6] %/year	US/CAN Exchange Rate[7] $US/$Cdn
2013	92.50	87.50	65.60	75.30	83.10	3.35	97.50	2.0	1.000
2014	92.50	90.50	67.90	77.80	86.00	3.85	95.60	2.0	1.000
2015	93.60	92.60	69.50	79.60	88.00	4.35	95.70	2.0	1.000
2016	95.50	94.50	70.90	81.30	89.80	4.70	97.70	2.0	1.000
2017	97.40	96.40	72.30	82.90	91.60	5.10	99.60	2.0	1.000
2018	99.40	98.30	73.70	84.50	93.40	5.45	101.60	2.0	1.000
2019	101.40	100.30	75.20	86.30	95.30	5.55	103.70	2.0	1.000
2020	103.40	102.30	76.70	88.00	97.20	5.70	105.70	2.0	1.000
2021	105.40	104.30	78.20	89.70	99.10	5.80	107.80	2.0	1.000
2022	107.60	106.50	79.90	91.60	101.20	5.90	110.10	2.0	1.000
2023	109.70	108.50	81.40	93.30	103.10	6.00	112.20	2.0	1.000
2024	111.90	110.70	83.00	95.20	105.20	6.15	114.40	2.0	1.000
2025	114.10	112.90	84.70	97.10	107.30	6.25	116.70	2.0	1.000
2026	116.40	115.20	86.40	99.10	109.40	6.35	119.10	2.0	1.000
2027	118.80	117.50	88.10	101.10	111.60	6.50	121.50	2.0	1.000
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	2.0	1.000

(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, 2012, were $2.58/mcf for natural gas, $56.54/bbl for natural gas liquids, $80.17/bbl for light/medium oil, and $71.35/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-11[1]	**44.9**	**19.9**	**64.8**	**56.4**	**22.8**	**79.2**	**93.6**	**165.6**	**259.2**
Extensions/Improved Recovery	1.9	1.7	3.5	2.7	2.8	5.4	-	-	-
Technical Revisions	0.7	(2.1)	(1.4)	(0.8)	(2.5)	(3.4)	0.5	(0.5)	-
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(1.8)	(0.8)	(2.5)	(0.6)	(0.2)	(0.8)	-	-	-
Production[2]	(5.6)	-	(5.6)	(7.3)	-	(7.3)	-	-	-
31-Dec-12	**40.1**	**18.7**	**58.8**	**50.5**	**22.8**	**73.2**	**94.1**	**165.1**	**259.2**

	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-11[1]	**336.3**	**149.3**	**485.6**	**14.2**	**7.4**	**21.6**	**265.2**	**240.6**	**505.7**
Extensions/Improved Recovery	20.1	24.2	44.3	1.2	1.9	3.1	9.1	10.3	19.4
Technical Revisions	9.0	(17.9)	(9.1)	2.0	-	2.1	3.8	(8.0)	(4.3)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(4.3)	(1.5)	(5.8)	(0.1)	-	(0.1)	(3.1)	(1.3)	(4.4)
Production[2]	(45.0)	(0.1)	(45.1)	(2.3)	-	(2.3)	(22.7)	(0.1)	(22.8)
31-Dec-12	**316.1**	**153.9**	**470.0**	**15.0**	**9.3**	**24.3**	**252.3**	**241.5**	**493.8**

(1) The closing balance from 2011 does not match the opening balance in 2012. In preparing the 2011 reserves tables, the actual production was different than that estimated by the Independent Qualified Reserves Evaluators, since their reports were prepared before the 2011 actual production was available. An update for this variance was accounted for by adjusting the 2011.

(2) The stated 2012 production of 22.7 and 22.8 mmboe in this table does not line up with the actual recorded production of 21.7 mmboe for Harvest in 2012. This is for the same reason as discussed above – Independend Qualified Reserves Evaluators' reports were prepared before 2012 actual production was available and therefore their reports refects estimates for 2012 production.

(3) Coal bed methane of 1.5 Bcf proved and 2.2 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, 2013, Harvest has a total of 128.3 MMboe of gross reserves that are classified as proved non-producing. Of these non-producing reserves, approximately 95% are undeveloped reserves. The balance are developed non-producing reserves which would be wells that were not producing as of December 31, 2012 and are eligible to be brought on production given economics and production information as at January 1, 2013.

Timing of Initial Undeveloped Reserves Assignment

			Gross Reserves First Attributed by Year				
Reserves Category	Product Type	Units	Prior	2010	2011	2012	Total[(1)]
Proved Undeveloped							
	Light and Medium Crude Oil	MMbbl	3.9	2.9	0.6	0.3	7.7
	Heavy Crude Oil	MMbbl	11.4	1.3	1.3	0.3	14.3
	Natural Gas	Bcf	27.2	3.8	40.6	14.0	85.6
	Natural Gas Liquids	MMbbl	-	0.2	1.5	1.0	2.7
	Bitumen	MMbbl	-	94.1	-	-	94.1
	Total Oil Equivalent	MMboe	19.9	99.1	10.1	3.9	133.0
Probable Undeveloped							
	Light and Medium Crude Oil	MMbbl	11.1	2.6	1.0	0.5	15.2
	Heavy Crude Oil	MMbbl	9.4	1.5	0.6	0.3	11.7
	Natural Gas	Bcf	25.9	9.5	34.6	21.2	91.2
	Natural Gas Liquids	MMbbl	1.1	0.2	2.7	1.6	5.6
	Bitumen	MMbbl	-	165.1	-	-	165.1
	Total Oil Equivalent	MMboe	25.9	171.0	10.0	5.9	212.8

(1) The "Total" column may not reflect the reserves at year-end detailed in the "Summary of Oil & Gas Reserves" table above due to changes in reserves resulting from improved recovery and technical revisions, which are not reflected in this table. The first attributed volumes include only additions during the 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 20% of these reserves are expected to be developed within the next two years (pending product pricing and capital availability). The remaining 80% 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 83% and 88% of Harvest's proved undeveloped and probable undeveloped reserves, respectively, attributed in the past three years are located on Harvest's BlackGold oil sands property. At the end of 2012, Harvest's BlackGold oil sands project had proved undeveloped bitumen reserves of 94.1 mmbbl and probable undeveloped bitumen reserves of 165.1 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, 2012.

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
2013	508	580
2014	265	496
2015	119	381
2016	70	580
2017	21	217
Thereafter	1,144	2,877
Total Undiscounted	**2,127**	**5,130**
Total Discounted at 10%	1,103	2,387

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, 2012 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, 2012 further discussion.

Estimated future downhole costs related to a property have been taken into account by the Independent Qualified Reserves Evaluators 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 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 Reports and developing new proven reserves previously not evaluated by the Independent Qualified Reserves Evaluators. 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, 2012

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 2012, Hay River produced 6,149 boe/day (including a trace – 13 barrels per day – of condensate) of 24^{o} API crude oil 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 2012, Harvest drilled 31 gross 100% Working Interest wells, including 22 horizontal producing wells, 8 water injection wells and 1 water source well, and established new infrastructure with a total capital expenditure of $79 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 2012 from Red Earth averaged 4,149 boe/d (98% oil), with an average oil quality of 37° to 39° API from the Slave Point, Granite Wash and Gilwood Formations. Harvest increased its Working Interest in this area to over 90% following the acquisition of the remaining 40% interest in the Red Earth Partnership in the fall of 2010 and has been actively adding to its land base through Crown land sales, including a partnership with the Loon Lake First Nations for an option on up to 26 sections of land in 2012, on which drilling will commence in Q3 2013.

In 2012, Harvest drilled 13 gross wells with total capital expenditures, including roads and pipelines, of $73 million. A majority of the drilling was made up of horizontal wells in the Slave Point Formation using multi-staged fractured completions. Harvest has an extensive seismic database in the Red Earth area that was instrumental in the discovery of new Gilwood and Granite Wash oil pools in the area and placement of Slave Point horizontal wells. Two of the 13 wells drilled in 2012 were for the Gilwood formation.

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 2012 for the area increased by 8% from 2011 to 16,480 boe/d (64% gas).

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

In 2012, Harvest participated in 11 gross wells (7 oil, 3 gas and 1 injection well) for a total capital expenditure $46 million, including $10 million in capital upgrades at Shell's Caroline Gas Plant in which Harvest is an 8.2% Working Interest owner.

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 2012, the average production was 7,671 boe/d (88% oil) and is primarily heavy and medium oil from 18^{o} to 32^{o} API. The Corporation's largest polymer flood in Wainwright is in this group along with large legacy properties such as Bellshill, Provost and Bashaw. This area remains largely focusses on EOR and optimization of current wells and facilities. In 2012, Harvest participated in 6 gross wells, all of which were successful, for a total capital expenditure of approximate $6 million.

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 2012 grew 44% over 2011 volumes to 5,312 boe/d (85% gas). Legacy production is from vertical wells completed in multiple zones (Falher, Cardium, Cadotte, Cadomin, Bluesky, Dunvegan, and Gething) and comingled together. 2011 and 2012 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), which has liquids content between 50 and 100 barrels per mmcf. In 2012, Harvest participated in 5 gross wells and added to our land base and expanded our gathering system infrastructure for a net cost of $57 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 7,990 boe/d (96% oil) in 2012. Harvest drilled 25 gross wells in 2012 with total net capital expenditures of $38 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 as well as production near the City of Kindersley in western Saskatchewan, near the Alberta border. The Kindersley assets are produced from stage-fractured horizontal wells in the Viking formation. 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 2012 was 4,288 boe/d (96% oil). In 2012, Harvest participated in 21 gross wells (11 in SE Saskatchewan and 10 in Kindersley) with a total net capital expenditure of $42 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.

The BlackGold oil sands project continued to progress through 2012 with the drilling of 15 SAGD (Steam Assisted Gravity Drainage) injection – producer well pairs. In 2012, 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. Phase 1 will inject steam for several months and then begin oil production, with a targeted rate of 10,000 boe/d. Regulatory work on Harvest's expansion plan to 30,000 boe/d continued throughout 2012 and regulatory approval of Phase 2 is expected sometime in 2013. After that approval, detailed engineering and expansion planning will begin.

BlackGold's capital program in 2012 was $164 million and was applied to the drilling of the 15 well pairs and 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, 2012:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing(1)		Producing		Non-Producing(1)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	3,190	2,374	1,226	896	1,915	623	935	386
British Columbia	550	385	131	55	68	16	106	46
Saskatchewan	963	775	598	464	6	2	56	46
Total	4,703	3,534	1,955	1,415	1,989	641	1,097	478

(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, 2012:

	Undeveloped Land (Hectares)(1)	
	Gross	Net
Alberta	311,673	225,263
British Columbia	121,949	73,903
Saskatchewan	29,207	25,599
Total	462,829	324,765

	Undeveloped Hectares with Rights(1) Expiring Within One Year	
	Gross	Net
Alberta	29,674	24,605
British Columbia	23,026	17,541
Saskatchewan	4,268	4,268
Total	56,968	46,414

(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, 2012	1,701.9	266.4
Anticipated to be paid in 2013	24.6	22.3
Anticipated to be paid in 2014	29.6	24.5
Anticipated to be paid in 2015	27.9	21.0

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 for each operating area are based on the Energy Resources Conservation Board ("ERCB") methodology from 2005 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 Evaluators. The cumulative yearly costs that will be incurred for suspended wells are based on ERCB 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.

The number of net wells (oil and gas, producing and non-producing) for which the Independent Qualified Reserves Evaluators estimated that Harvest would incur downhole abandonment costs is 6,068 wells (proved plus probable) at December 31, 2012.

Abandonment costs (excluding salvage values) associated with wells to which reserves were attributed, were deducted by the Independent Reserves Evaluators 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 Evaluators, are $1,395.9 million ($194.8 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 2022. 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, 2012:

($ millions)	Oil & Gas Capital Expenditures (Excluding Oil Sands)	Oil Sands Capital Expenditures	Total Capital Expenditures[1]
Property acquisition costs			
Proved properties	1.3	-	1.3
Unproved properties	-	-	-
Total property acquisition	1.3	-	1.3
Exploration costs	41.1	-	41.1
Development costs	402.6	164.1	566.7
Total	445.0	164.1	609.1

(1) Total capital expenditures exclude costs related to corporate assets of $1.5 million.

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells completed during 2012:

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

2013 Capital Expenditure Plan

Harvest's expected total capital spending on its oil and natural gas properties for 2013 is expected to be approximately $615 million. The primary areas of focus for Harvest's Upstream and BlackGold capital program during 2012 are the following:

- BlackGold – Expenditures of approximately $315 million to fund module assembly, transportation to site and on-site facility construction;
- Hay River – Drill 25 gross producing multi-leg horizontal oil wells and water injection wells (13 producers, 12 injectors) and pipeline infrastructure expansion for a total expenditure of $39 million;
- Red Earth – Drill 9 gross light oil wells, primarily at Loon Lake, but also in Gift, Evi and Golden areas, for a net expenditure of $36 million;
- West Central/Rimbey – Drill 5 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 for an expenditure of $19 million;

- Kindersley, Saskatchewan – Drill 10 gross horizontal wells into the Viking Formation for a total expenditure of $12 million;
- Deep Basin Area – Drill 4 gross Falher horizontal stage-fractured liquids-rich natural gas for a total expenditure of $21 million;
- Cecil – Drill 4 Charlie Lake horizontal, unstimulated oil wells for $8 million;
- Southeast Saskatchewan Area – Drill 4 gross horizontal light oil wells into the Souris Valley and Tilston formations and build an oil battery for a total expenditure of $8 million;
- Suffield and Wainwright – Drill 5 wells and expand and continue to inject polymer into the two existing EOR floods for a total expenditure of $16 million; and
- Various Areas
    - Expenditures of approximately $12 to $15 million to exploration projects which includes drilling, seismic and land purchases;
    - Expenditures of $31 million to optimize existing producing wells and facilities and $20 million to highgrade or replace existing production infrastructure; and
    - Expenditures of $26 million for land and seismic to set up future development opportunities, and $13 to $14 million each to abandon wells, 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 2012 year-end Reserves Report:

2013 Production Forecast
Before Royalty Interests

	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	Total
	bbl/d	bbl/d	mcf/d	bbl/d	boe/d
Proved Producing	15,384	15,012	99,371	5,378	52,336
Proved Developed Non-Producing	306	52	776	24	511
Proved Undeveloped	614	2,419	10,039	680	5,386
Total Proved	16,304	17,484	110,186	6,082	58,234
Total Probable	1,326	1,238	8,187	527	4,456
Total Proved Plus Probable	17,630	18,722	118,373	6,609	62,690

The estimated production volumes for the property that accounts for more than 20% of Harvest's total forecast 2013 production is West Central Alberta, with estimated production of 13,414 boe/d.

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

	2012				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil (bbl/d)	14,380	13,758	13,603	13,817	13,889
Heavy Oil (bbl/d)	19,828	20,701	19,110	18,402	19,506
Total Oil (bbl/d)	34,208	34,459	32,713	32,219	33,395
NGLs (bbl/d)	5,668	5,469	4,920	6,084	5,535
Natural Gas(mcf/d)	124,045	125,680	120,315	119,554	122,385
Total Daily Production (boe/d)	60,550	60,874	57,686	58,228	59,327

Total Sales Production

	2012				
	Q1	Q2	Q3	Q4	Total
Light and Medium Oil (MMbbl)	1.3	1.2	1.2	1.3	5.0
Heavy Oil (MMbbl)	1.8	1.9	1.8	1.7	7.2
Total Oil (MMbbl)	3.1	3.1	3.0	3.0	12.2
NGLs (MMbbl)	0.5	0.5	0.5	0.6	2.1
Natural Gas (Bcf)	11.3	11.4	11.1	11.0	44.8
Total Production (MMboe)	5.5	5.5	5.3	5.4	21.7

Average Sales Prices Received

	2012				
	Q1	Q2	Q3	Q4	Total
Light & Medium oil ($/bbl) (1)	86.62	78.68	78.72	76.42	80.17
Heavy Oil ($/bbl)	78.64	69.33	69.57	67.66	71.35
Total Oil ($/bbl)	81.99	70.55	70.76	71.42	75.01
NGLs ($/bbl)	63.20	56.76	53.01	53.06	56.54
Natural Gas ($/mcf)	2.29	2.11	2.52	3.44	2.58
Total ($/boe)	58.07	51.42	52.02	52.82	53.60

Royalties Paid

	2012				
	Q1	Q2	Q3	Q4	Total
($ millions)					
Light & Medium Oil	17.1	14.7	13.0	12.9	57.7
Heavy Oil	25.4	21.5	21.1	17.2	85.2
NGLs	7.6	1.7	1.4	3.6	14.3
Natural gas	3.3	0.9	1.2	2.0	7.4
Total	53.4	38.8	36.7	35.7	164.6
Light & Medium Oil ($/bbl)	13.05	12.80	11.28	10.17	11.36
Heavy Oil ($/bbl)	14.07	11.43	11.98	10.18	11.93
NGLs (S/bbl)	14.69	3.48	3.08	6.36	7.04
Natural gas ($/boe)	1.74	0.47	0.63	1.07	0.99
Total ($/boe)	9.69	7.00	6.92	6.66	7.58

Operating Expenses

	2012				
	Q1	Q2	Q3	Q4	Total
($ millions)					
Light & Medium Oil	31.7	27.3	29.6	23.1	111.7
Heavy Oil	37.6	32.4	34.5	32.3	136.8
NGLs	6.5	6.0	5.9	4.9	23.3
Natural gas	24.2	22.8	23.1	17.1	87.2
Total	100.0	88.5	93.1	77.4	359.0
Light & Medium Oil ($/bbl)	24.26	23.74	25.71	18.14	21.97
Heavy Oil ($/bbl)	20.86	17.20	19.62	19.06	19.16
NGLs ($/boe)	12.69	11.98	12.97	8.68	11.52
Natural Gas ($/boe)	12.89	11.98	12.52	9.34	11.68
Total ($/boe)	18.14	15.98	17.55	14.45	16.54

Netback Received[(2)(3)]

	2012				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($/bbl) [(1)]	49.31	42.14	41.73	48.11	46.84
Heavy Oil ($/bbl)	43.71	40.70	37.97	38.42	40.26
NGLs ($/bbl)	35.82	41.31	36.96	38.02	37.98
Natural Gas ($/boe)	(0.88)	0.23	1.94	10.24	2.83
Total ($/boe)	30.24	28.44	27.55	31.71	29.48

(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.

2012 Historical Production by Material Property

Material Property	Light & Medium Crude Oil bbl/d	Heavy Oil bbl/d	Natural Gas mcf/d	NGLs bbl/d	Average Daily Production boe/d
Hay River	-	5,867	1,595	16	6,149
Red Earth	4,047	-	189	71	4,149
West Central Alberta	1,390	344	63,099	4,229	16,480
East Central Alberta	2,883	3,894	4,599	127	7,671
Deep Basin	18	-	27,114	775	5,312
Heavy Oil	-	7,668	1,749	31	7,990
Saskatchewan Light Oil	4,102	-	978	24	4,288
Other	1,449	1,733	23,062	262	7,288
Total	13,889	19,506	122,385	5,535	59,327

Reclassification of Heavy Oil and Light to Medium Oil Volumes

Effective October 1, 2012, Harvest reclassified certain properties that were previously reported as light to medium oil to heavy oil as classified under National Instrument 51-101. As a result, average daily production volumes, sales production, average sales prices received, royalties paid, operating expenses and netback received for light to medium oil and heavy oil have been adjusted to reflect the reclassification. The reclassification did not result in any changes to the total average daily production volumes, sales production, sales prices received, royalties, operating expenses or netback received previously reported by the Corporation. The following tables illustrate the changes resulting from the reclassification for each quarter of 2011:

Average Daily Production Volumes

	2011				
	Q1	Q2	Q3	Q4	Total
Revised classification					
Light & Medium Oil (bbl/d)	14,408	13,147	14,777	15,161	14,376
Heavy Oil (bbl/d)	20,153	17,706	17,669	20,466	18,996
Total Oil (bbl/d)	34,561	30,853	32,446	35,627	33,372
Previously reported					
Light & Medium Oil (bbl/d)	25,523	22,294	23,621	26,106	24,380
Heavy Oil (bbl/d)	9,038	8,559	8,825	9,521	8,992
Total Oil (bbl/d)	34,561	30,853	32,446	35,627	33,372

Total Sales Production

	2011				
	Q1	Q2	Q3	Q4	Total
Revised classification					
Light and Medium Oil (MMbbl)	1.3	1.2	1.4	1.4	5.3
Heavy Oil (MMbbl)	1.8	1.6	1.6	1.9	6.9
Total Oil (MMbbl)	3.1	2.8	3.0	3.3	12.2
Previously reported					
Light and Medium Oil (MMbbl)	2.3	2.0	2.2	2.4	8.9
Heavy Oil (MMbbl)	0.8	0.8	0.8	0.9	3.3
Total Oil (MMbbl)	3.1	2.8	3.0	3.3	12.2

Average Sales Prices Received

	2011				
	Q1	Q2	Q3	Q4	Total
Revised classification					
Light & Medium oil ($/bbl) [(1)]	81.00	96.54	84.49	92.01	88.37
Heavy Oil ($/bbl)	69.34	82.96	68.25	83.40	76.07
Total Oil ($/bbl)	74.20	88.74	75.65	87.06	81.37
Previously reported					
Light & Medium oil ($/bbl) [(1)]	78.69	94.08	80.43	89.90	85.67
Heavy Oil ($/bbl)	61.51	74.84	62.84	79.28	69.71
Total Oil ($/bbl)	74.20	88.74	75.65	87.06	81.37

Royalties Paid

	2011				
	Q1	Q2	Q3	Q4	Total
Revised classification					
Light & Medium Oil ($ millions)	13.3	16.5	21.7	20.5	72.0
Light & Medium Oil ($/bbl)	10.29	13.80	15.95	14.69	13.72
Heavy Oil ($ millions)	20.4	22.8	16.6	23.9	83.7
Heavy Oil ($/bbl)	11.22	14.13	10.24	12.69	12.07
Previously reported					
Light & Medium Oil ($ millions)	26.8	30.9	31.0	36.0	124.7
Light & Medium Oil ($/bbl)	11.65	15.21	14.29	15.00	14.01
Heavy Oil ($ millions)	6.9	8.4	7.3	8.4	31.0
Heavy Oil ($/bbl)	8.53	10.81	8.98	9.56	9.45

Operating Expenses

	2011				
	Q1	Q2	Q3	Q4	Total
Revised classification					
Light & Medium Oil ($ millions)	27.0	28.3	29.8	31.9	117.0
Light & Medium Oil ($/bbl)	20.80	23.68	21.90	22.85	22.28
Heavy Oil ($ millions)	38.5	28.8	31.1	36.2	134.6
Heavy Oil ($/bbl)	21.22	17.84	19.16	19.20	19.41
Previously reported					
Light & Medium Oil ($ millions)	48.8	41.4	44.6	48.6	183.4
Light & Medium Oil ($/bbl)	21.23	20.41	20.52	20.22	20.60
Heavy Oil ($ millions)	16.7	15.7	16.3	19.5	68.2
Heavy Oil ($/bbl)	20.53	20.12	20.11	22.23	20.78

Netback Received (2)(3)

	2011				
	Q1	Q2	Q3	Q4	Total
Revised classification					
Light & Medium Oil ($/bbl) (1)	49.91	59.06	46.64	54.47	52.37
Heavy Oil ($/bbl)	36.90	50.99	38.85	51.51	44.59
Previously reported					
Light & Medium Oil ($/bbl) (1)	45.81	58.46	45.62	54.68	51.06
Heavy Oil ($/bbl)	32.45	43.91	33.75	47.49	39.47

(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.

The following table illustrates the light to medium and heavy oil average daily production changes resulting from the reclassification for each material property in 2011:

Material Property	Light & Medium Oil bbl/d	Heavy Oil bbl/d	Light, Medium & Heavy Crude Oil bbl/d
Hay River	–	4,734	4,734
Red Earth	3,957	–	3,957
West Central Alberta	1,483	476	1,959
East Central Alberta	3,503	4,095	7,598
Deep Basin	22	–	22
Heavy Oil	–	7,803	7,803
Saskatchewan Light Oil	3,940	–	3,940
Other	1,471	1,888	3,359
TOTAL	14,376	18,996	33,372

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, 2012.

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 EVALUATORS

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

1. We have evaluated the Company's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, 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, 2012 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)			
Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
McDaniel and Associates Consultants Ltd.	February 27, 2013	Canada	-	1,388	-	1,388
GLJ Petroleum Consultants Ltd.	BlackGold February 13, 2013	Canada	-	1,358	-	1,358
GLJ Petroleum Consultants Ltd.	February 13, 2013	Canada	-	2,223	-	2,223
Totals			-	4,969	-	4,969

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) "P. A. Welch", P. Eng.

McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

February 27, 2013

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

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

February 13, 2012

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, 2012, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluators 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 evaluators;

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

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

The RSE Committee 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 evaluators on the reserves data; and

(c) the content and filing of this report.

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

(Signed)
Myunghuhn Yi
President & CEO

(Signed)
YS Kim
Deputy Chief Operating Officer

(Signed)
Brant Sangster
Director

(Signed)
William A. Friley
Director

March 28, 2013