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

For the year ended December 31, 2017

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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.

"BlackGold" means the BlackGold Oil Sands property which is the principal property contained in the Corporation's Oil Sands business segment.

"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.

"Contingent Resources" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies**.**

"Conventional" means Harvest's petroleum and natural gas segment, consisting of the exploitation, production and subsequent sale of petroleum, natural gas and natural gas liquids in Alberta and British Columbia.

"Credit Facility" means the $500 million revolving credit facility, which replaced the $1 billion revolving credit facility on February 24, 2017, provided by a syndicate of lenders to Harvest Operations Corp. For further details, refer to the "General Description of Capital Structure" in Harvest's Annual Information Form for December 31, 2017, which is available on SEDAR at www.sedar.com.

"Deep Basin Partnership" or "DBP" means Harvest's upstream joint venture with KERR Canada Co. Ltd. ("KERR") formed on April 23, 2014. As at December 31, 2017, Harvest owned 632,091,512 of common partnership units in Deep Basin Partnership representing an approximately 82.59% equity interest.

"Development Costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs include 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 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) dry 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.

"Equity Investment" means Harvest's equity interest in the Deep Basin Partnership.

"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,

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, 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, 2017 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.

"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 Harvest's interest in 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.

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

"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

a) analysis of drilling, geological, geophysical and engineering data;

b) the use of established technology; and

c) 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.

c) **Possible Reserves** are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible 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 oil sands 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
DBP	Deep Basin Partnership
EOR	Enhanced oil recovery
GJ	Gigajoule
H_2S	Hydrogen sulfide gas
Mcf	Thousand cubic feet
MMbbls	Million barrels
MMboe	Million barrels of oil equivalent
MMbtu	Million of British thermal units
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, Harvest's Equity Investment, and Harvest's BlackGold property are dated January 23, 2018. The effective date of the reserves and future net revenue information provided is December 31, 2017, unless otherwise indicated. The information contained herein was prepared on March 28, 2018.

DISCLOSURE OF RESERVES DATA

Harvest retained an Independent Qualified Reserves Evaluator to evaluate and prepare reports on 100% of Harvest's Reserves as of December 31, 2017. Harvest's Reserves were evaluated by GLJ. Possible Reserves were not evaluated, with the exception of the BlackGold oil sands property where GLJ evaluated Possible Reserves and Contingent Resources.

Harvest's investment in Deep Basin Partnership ("DBP") is accounted for using the equity method of accounting and pursuant to NI 51-101, Harvest is required to separately disclose information concerning DBP's oil and gas reserves, future net revenue and costs incurred based on Harvest's equity interest in DBP. Accordingly, in certain tables that follow, information is first provided in respect of Harvest and its Operating Subsidiaries, which are consolidated for financial reporting purposes (under the heading "Consolidated Entities") and then in respect of DBP (under the heading "Equity Investment"). GLJ evaluated 100% of DBP's natural gas and NGLs reserves as at December 31, 2017. All information with respect to DBP reflects Harvest's 82.59% equity interest in DBP as at December 31, 2017, except for per unit information.

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

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 the reserves of Harvest's Consolidated Entities and Equity Investment as evaluated in the report prepared by 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 data contained in the Reserves Reports and as a result may contain slight rounding differences although they are substantively the same as the data in the Reserves Reports. Totals may not add due to rounding.

All Reserves are located in Canada and, in the provinces of Alberta and British Columbia.

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.

Reserves Data (Forecast Prices and Costs)

The following tables detail the aggregate gross and net Reserves of Harvest's Consolidated Entities and Equity Investment, at December 31, 2017, using forecast prices and costs as well as 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%.

Summary of Oil & Gas Reserves
As of December 31, 2017
Forecast Prices and Costs

Consolidated Entities	Light and Medium Oil (MMbbls)		Heavy Oil (MMbbls)		Bitumen (MMbbls)		Conventional Natural Gas (Bcf)		Shale Natural Gas (Bcf)		Natural Gas Liquids (MMbbls)		Total Oil Equivalent (MMboe)	
Reserves Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved														
Developed Producing	14.6	13.3	5.1	4.7	—	—	138.3	128.1	—	—	6.2	4.8	49.0	44.2
Developed Non-Producing	1.8	1.6	1.2	1.1	—	—	11.2	10.1	—	—	0.6	0.5	5.4	4.9
Undeveloped	6.1	5.2	0.3	0.3	96.0	88.8	114.3	103.8	—	—	4.5	4.1	126.0	115.7
Total Proved	22.5	20.1	6.6	6.1	96.0	88.8	263.8	242.0	—	—	11.3	9.4	180.4	164.8
Probable	15.0	13.2	3.4	3.0	163.2	135.8	169.5	152.7	—	—	6.2	5.2	216.0	182.7
Total Proved + Probable	37.5	33.3	10.0	9.1	259.2	224.6	433.3	394.7	—	—	17.5	14.6	396.4	347.5
Equity Investment														
Reserves Category														
Proved														
Developed Producing	—	—	—	—	—	—	19.1	17.0	6.5	6.1	1.4	1.0	5.7	4.9
Developed Non-Producing	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	0.6	0.6	24.0	22.6	2.9	2.6	7.0	6.5
Total Proved	—	—	—	—	—	—	19.7	17.6	30.5	28.7	4.3	3.6	12.7	11.4
Probable	—	—	—	—	—	—	25.4	22.6	52.7	48.3	6.9	6.0	19.9	17.8
Total Proved + Probable	—	—	—	—	—	—	45.1	40.2	83.2	77.0	11.2	9.6	32.6	29.2
Total(1)														
Reserves Category														
Proved														
Developed Producing	14.6	13.3	5.1	4.7	—	—	157.4	145.1	6.5	6.1	7.6	5.8	54.7	49.1
Developed Non-Producing	1.8	1.6	1.2	1.1	—	—	11.2	10.1	—	—	0.6	0.5	5.4	4.9
Undeveloped	6.1	5.2	0.3	0.3	96.0	88.8	114.9	104.4	24.0	22.6	7.4	6.7	133.0	122.2
Total Proved	22.5	20.1	6.6	6.1	96.0	88.8	283.5	259.6	30.5	28.7	15.6	13.0	193.1	176.2
Probable	15.0	13.2	3.4	3.0	163.2	135.8	194.9	175.3	52.7	48.3	13.1	11.2	235.9	200.5
Total Proved + Probable	37.5	33.3	10.0	9.1	259.2	224.6	478.4	434.9	83.2	77.0	28.7	24.2	429.0	376.7

(1) Total Consolidated Entities plus Total Equity Investment

Summary of Net Present Values of Future Net Revenue
As of December 31, 2017
Forecast Prices and Costs

Consolidated Entities	Before Income Taxes Discounted at %/year ($ millions)					NPV 10%/boe
Reserves Category	0%	5%	10%	15%	20%	($/boe)(1)
Proved						
Developed Producing	629	548	480	426	383	10.86
Developed Non-Producing	85	69	58	49	42	11.84
Undeveloped	1,659	919	549	343	220	4.75
Total Proved	2,373	1,536	1,087	818	645	6.60
Probable	4,182	1,843	878	422	185	4.81
Total Proved + Probable	6,555	3,379	1,965	1,240	830	5.65
Equity Investment						
Reserves Category						
Proved						
Developed Producing	60	50	43	38	33	8.78
Developed Non-Producing	0	0	0	0	0	0.00
Undeveloped	81	34	12	1	(4)	1.85
Total Proved	141	84	55	39	29	4.82
Probable	309	143	73	39	20	4.10
Total Proved + Probable	450	227	128	78	49	4.38
Total(2)						
Reserves Category						
Proved						
Developed Producing	689	598	523	464	416	10.65
Developed Non-Producing	85	69	58	49	42	11.84
Undeveloped	1,740	953	561	344	216	4.59
Total Proved	2,514	1,620	1,142	857	674	6.48
Probable	4,491	1,986	951	460	205	4.74
Total Proved + Probable	7,005	3,606	2,093	1,317	879	5.56

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

(2) Total Consolidated Entities plus Total Equity Investment

	Summary of Net Present Values of Future Net Revenue As of December 31, 2017 Forecast Prices and Costs				
Consolidated Entities	After Income Taxes Discounted at (%/year) ($ millions)				
Reserves Category	0%	5%	10%	15%	20%
Proved					
Developed Producing	629	548	480	426	383
Developed Non-Producing	85	70	58	49	42
Undeveloped	1,504	864	528	335	216
Total Proved	2,218	1,482	1,066	810	641
Probable	3,296	1,459	691	322	128
Total Proved + Probable	5,514	2,941	1,757	1,132	769
Equity Investment					
Reserves Category					
Proved					
Developed Producing	59	50	43	38	34
Developed Non-Producing	0	0	0	0	0
Undeveloped	59	22	5	(3)	(7)
Total Proved	118	72	48	35	27
Probable	225	100	47	21	7
Total Proved + Probable	343	172	95	56	34
Total(1)					
Reserves Category					
Proved					
Developed Producing	688	598	523	464	417
Developed Non-Producing	85	70	58	49	42
Undeveloped	1,563	886	533	332	209
Total Proved	2,336	1,554	1,114	845	668
Probable	3,521	1,559	738	343	135
Total Proved + Probable	5,857	3,113	1,852	1,188	803

(1) Total Consolidated Entities plus Total Equity Investment

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 Harvest's Consolidated Entities and Equity Investment; and (ii) the future net revenue by production group in each reserves category:

Total Future Net Revenue (undiscounted)
As of December 31, 2017
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
Consolidated Entities								
Proved	9,356	826	4,313	1,505	339	2,373	155	2,218
Proved + Probable	23,023	3,036	8,539	4,408	485	6,555	1,041	5,514
Equity Investment								
Reserves Category								
Proved	502	45	194	116	6	141	23	118
Proved + Probable	1,395	158	478	299	10	450	107	343
Total[(1)]								
Reserves Category								
Proved	9,858	871	4,507	1,621	345	2,514	178	2,336
Proved + Probable	24,418	3,194	9,017	4,707	495	7,005	1,148	5,857

(1) Total Consolidated Entities plus Total Equity Investment

Future Net Revenue by Production Group
As of December 31, 2017
Forecast Prices and Costs

Reserves Category	Production Group	Before Income Taxes (discounted at 10%/year) ($ millions)	Unit Value[(3)]
Consolidated Entities			
Proved Reserves	**Conventional Reserves**		
	Light and Medium Crude Oil [(1)]	301	$13.62/bbl
	Heavy Crude Oil[(1)]	93	$14.28/bbl
	Conventional Natural Gas[(2)]	242	$0.85/mcf
	Non-Conventional Reserves		
	Bitumen	451	$5.08/bbl
	Total	**1,087**	**$6.60/boe**
Proved + Probable	**Conventional Reserves**		
Reserves	Light and Medium Crude Oil [(1)]	513	$14.01/bbl
	Heavy Crude Oil[(1)]	141	$14.43/bbl
	Conventional Natural Gas[(2)]	399	$0.87/mcf
	Non-Conventional Reserves		
	Bitumen	912	$4.06/bbl
	Total	**1,965**	**$5.65/boe**

Equity Investment Reserves Category			
Proved Reserves	**Conventional Reserves**		
	Conventional Natural Gas(2)	22	$1.07/mcf
	Non-Conventional Reserves		
	Shale Natural Gas(2)	33	$0.69/mcf
	Total	**55**	**$4.82/boe**
Proved + Probable Reserves	**Conventional Reserves**		
	Conventional Natural Gas(2)	37	$0.80/mcf
	Non-Conventional Reserves		
	Shale Gas(2)	91	$0.71/mcf
	Total	**128**	**$4.38/boe**

Total(4) Reserves Category			
Proved Reserves	**Conventional Reserves**		
	Light and Medium Crude Oil (1)	301	$13.62/bbl
	Heavy Crude Oil(1)	93	$14.28/bbl
	Conventional Natural Gas(2)	264	$0.86/mcf
	Non-Conventional Reserves		
	Bitumen	451	$5.08/bbl
	Shale Gas(2)	33	$0.69/mcf
	Total	**1,142**	**$6.48/boe**
Proved + Probable Reserves	**Conventional Reserves**		
	Light and Medium Crude Oil (1)	513	$14.01/bbl
	Heavy Crude Oil(1)	141	$14.43/bbl
	Conventional Natural Gas(2)	436	$0.86/mcf
	Non-Conventional Reserves		
	Bitumen	912	$4.06/bbl
	Shale Gas(2)	91	$0.71/mcf
	Total	**2,093**	**$5.56/boe**

(1) Includes solution gas and associated by-products
(2) Includes associated by-products
(3) Unit values are based upon net reserves volumes
(4) Total Consolidated Entities plus Total Equity Investment

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. Crude Oil, NGLs and Natural Gas benchmark reference pricing, inflation and exchange rates utilized in the Reserves Report are based on the average of the Sproule, McDaniel and GLJ January 1, 2018 price forecasts, as summarized below. A complete listing of the individual forecasts used to derive the blended forecast can be found on the websites of these three Independent Qualified Reserves Evaluators:

Summary of Pricing and Inflation Rate Assumptions – Average of GLJ, Sproule and McDaniel
As of January 1, 2018
Forecast Prices and Costs

	OIL				Natural Gas	Natural Gas Liquids					
Year	WTI Crude Oil(1) (US$/bbl)	Edmonton Light Crude Oil(2) (Cdn$/ bbl)	Alberta Bow River Hardisty Crude (Cdn$/ bbl)	WCS Crude Oil(4) (Cdn$/ bbl)	Alberta AECO Spot Price (Cdn$/ mmbtu)	Spec Ethane (Cdn$/ btu)	Edmonton Propane (Cdn$/ bbl)	Edmonton Butane (Cdn$/ bbl)	Edmonton C5+ Steam Quality (Cdn$/ bbl)	Inflation Rate(6) (%/Year)	Exchange Rate(7) (US$/Cdn$)
2018	57.50	68.60	51.23	50.61	2.43	7.61	35.69	51.29	72.41	0.7	0.790
2019	60.90	72.02	57.52	56.59	2.77	8.79	35.82	52.29	74.90	2.0	0.800
2020	64.13	74.48	61.56	60.86	3.19	10.21	34.85	53.92	77.07	2.0	0.817
2021	68.33	78.60	65.27	64.56	3.48	11.22	36.07	56.70	81.07	2.0	0.828
2022	71.19	80.84	67.35	66.63	3.67	11.90	35.89	58.32	83.32	2.0	0.840
2023	73.15	82.83	69.24	68.49	3.76	12.18	36.28	59.72	85.35	2.0	0.843
2024	75.16	85.17	71.39	70.63	3.85	12.42	37.39	61.42	87.75	2.0	0.843
2025	77.17	87.53	73.55	72.79	3.93	12.67	38.50	63.08	90.13	2.0	0.843
2026	79.01	89.66	75.49	74.72	4.02	12.98	39.52	64.60	92.32	2.0	0.843
2027	80.60	91.49	77.12	76.31	4.10	13.23	40.37	65.95	94.21	2.0	0.843
2028	82.20	93.31	78.65	77.84	4.19	13.55	41.24	67.26	96.11	2.0	0.843
Thereafter	2.0% /yr	2.0% /yr	2.0% /yr	2.0% /yr	2.0% /yr	2.0% /yr	2.0% /yr	2.0% /yr	2.0% /yr	2.0% /yr	0.843

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

Weighted average historical prices prior to hedging realized by Harvest's Consolidated Entities for the year ended December 31, 2017, were $2.35/mcf for natural gas, $35.04/bbl for natural gas liquids, $56.69/bbl for light/medium oil, and $47.72/bbl for heavy oil.

Weighted average historical prices prior to hedging realized by the Deep Basin Partnership for the year ended December 31, 2017, were $2.55/mcf for natural gas and $51.76/bbl for natural gas liquids.

Reconciliation
By Principal Product Type
Forecast Prices and Cost

Factors	Light and Medium Oil (MMbbl)			Heavy Oil (MMbbl)			Bitumen (MMbbl)			Natural Gas Liquids (MMbbl)		
	Gross Proved	Gross Probable	Gross Proved + Probable	Gross Proved	Gross Probable	Gross Proved + Probable	Gross Proved	Gross Probable	Gross Proved + Probable	Gross Proved	Gross Probable	Gross Proved + Probable
31-Dec-16	**25.8**	**15.9**	**41.7**	**8.2**	**3.9**	**12.1**	**96.0**	**163.2**	**259.2**	**10.4**	**6.9**	**17.3**
Extensions	1.0	1.2	2.2	—	—	—	—	—	—	1.4	0.6	2.0
Improved Recovery	0.7	0.4	1.1	—	—	—	—	—	—	0.1	0.1	0.2
Technical Revisions	(3.1)	(2.4)	(5.5)	1.1	(0.5)	0.6	—	—	—	1.0	(1.4)	(0.4)
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(0.4)	(0.1)	(0.5)	(0.1)	—	(0.1)	—	—	—	(0.4)	—	(0.4)
Production(1)	(1.5)	—	(1.5)	(2.6)	—	(2.6)	—	—	—	(1.2)	—	(1.2)
31-Dec-17	**22.5**	**15.0**	**37.5**	**6.6**	**3.4**	**10.0**	**96.0**	**163.2**	**259.2**	**11.3**	**6.2**	**17.5**

Factors	Conventional Natural Gas (Bcf)			Total Oil Equivalent (MMboe)		
	Gross Proved	Gross Probable	Gross Proved + Probable	Gross Proved	Gross Probable	Gross Proved + Probable
31-Dec-16	**268.6**	**159.6**	**428.2**	**185.1**	**216.5**	**401.6**
Extensions	42.4	21.5	63.9	9.5	5.4	14.9
Improved Recovery	1.5	0.9	2.4	1.1	0.6	1.7
Technical Revisions	(0.4)	(16.1)	(16.5)	(1.1)	(7.0)	(8.1)
Dispositions	(7.8)	(2.9)	(10.7)	(1.3)	(0.5)	(1.8)
Economic Factors	(13.9)	6.5	(7.4)	(3.2)	1.0	(2.2)
Production(1)	(26.6)	—	(26.6)	(9.7)	—	(9.7)
31-Dec-17	**263.8**	**169.5**	**433.3**	**180.4**	**216.0**	**396.4**

**Table is for consolidated entities only.

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, 2018, Harvest's Consolidated Entities have a total of 131.4 MMboe of gross Reserves that are classified as Proved Non-Producing Reserves. 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, 2017 and may be brought on production given economics and production information as at January 1, 2018.

Gross Reserves First Attributed by Year[(1)]

	Light and Medium Crude (MMbbl)		Heavy Crude Oil (MMbbl)		Conventional Natural Gas (Bcf)		Natural Gas Liquids (MMbbl)		Shale Gas (Bcf)		Bitumen (MMbbl)		Total Oil Equivalent (MMboe)	
Proved Undeveloped	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	First Attributed	Total at Year End
Prior	1.8	1.8	6.1	6.1	68.4	68.4	3.0	3.0	0.0	0.0	96.0	96.0	118.3	118.3
2015	0.3	5.7	0.0	0.5	21.0	75.3	1.5	4.6	0.0	5.4	0.0	96.0	5.3	120.2
2016	0.2	5.9	0.0	0.5	39.3	114.6	0.1	3.9	0.0	0.0	0.0	96.0	6.9	125.4
2017	0.8	6.1	0.0	0.3	18.0	114.3	0.7	4.5	0.0	0.0	0.0	96.0	4.5	126.0
Probable Undeveloped	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	First Attributed	Total at Year End
Prior	5.7	5.7	6.2	6.2	55.1	55.1	4.0	4.0	0.0	0.0	163.2	163.2	188.4	188.4
2015	1.3	9.4	0.0	0.7	37.2	103.9	1.5	5.6	0.0	2.5	0.0	163.2	9.0	196.6
2016	0.1	7.9	0.0	0.4	29.5	107.5	0.3	4.7	0.0	0.0	0.0	163.2	5.3	194.1
2017	1.2	7.9	0.0	0.1	26.1	114.0	0.4	3.7	0.0	0.0	0.0	163.2	5.9	193.9

(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 long range development plans for the major assets noted elsewhere in this document. Excluding BlackGold's bitumen reserves, most of these reserves are expected to be developed between 2018 and 2023. 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.

Oil Sands Bitumen

Approximately 76% and 84% of Harvest's Proved Undeveloped and Probable Undeveloped Reserves, respectively, are located on Harvest's Oil Sands business segment, consisting of Harvest's BlackGold oil sands property. At the end of 2017, Harvest's BlackGold oil sands property had Proved Undeveloped bitumen reserves of 96.0 MMbbl and Probable Undeveloped bitumen reserves of 163.2 MMbbl. BlackGold Reserves will be recovered by using SAGD methodology.

The BlackGold project required the construction of a central processing facility (“CPF”) to generate steam used to recover the bitumen from the reservoir and process the emulsion brought back to the surface. The BlackGold CPF is designed to last for 25 years of useful life (with up to approximately 35 to 40 years of useful life based on adequate maintenance) while the life of the SAGD well pairs typically range from 7 – 15 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.

In the early stages of a SAGD project, a relatively small portion of Proved Reserves are developed as the number of drilled well pairs are 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 Reserves depends on when the well pair targeting those Reserves is scheduled during the life of the CPF and steam generators. Development of the Proved Undeveloped Reserves takes place in an orderly manner when existing SAGD well pairs reach production decline phase.

Harvest has delineated BlackGold bitumen Reserves with a high degree of certainty through core hole drilling and seismic data 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 addition, regulatory and corporate approvals must be obtained, funding must be in place and a reasonable development timeline must be established for Reserves to be classified as Proved Reserves.

Recognition of probable reserves requires sufficient drilling of stratigraphic wells, well coring and analysis, and geological mapping to establish reservoir suitability for SAGD. 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. The probable reserves related to the BlackGold project are limited to the Phase 2 area.

Phase one commissioning and first steam injection is expected to be completed in the second quarter of 2018, with first production anticipated in the third quarter of 2018.

During 2013, Harvest received regulatory approval for Phase 2, however, due to the longer development timeline and the requirement for corporate approval and funding, the Reserves related to Phase 2 have been classified as Probable Reserves instead of Proved Reserves.

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, 2017.

Future Development Costs

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

	Forecast Prices and Costs ($ millions)	
Year	Proved Reserves	Proved Plus Probable Reserves
2018	119	123
2019	98	182
2020	149	474
2021	75	595
2022	24	177
Thereafter	1,040	2,857
Total Undiscounted	**1,505**	**4,408**
Total Discounted at 10%	621	1,799

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 by 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, 2017 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, 2017 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's Consolidated Entities' portfolio of significant properties are aggregated into material areas and discussed below. All properties are located onshore in Canada.

In general, the properties include major oil accumulations which benefit from active pressure support due to underlying regional aquifers. Generally, the properties have predictable decline rates with costs of production and oil price key to determining the economic limits of production and ultimately the recoverable Reserves.

Harvest is actively engaged in cost reduction and production and Reserves replacement optimization efforts directed at Reserves addition to extend the economic life of these producing properties beyond the limits used in the Reserves Report. We also are developing new proven Reserves in our core and strategic assets previously not evaluated by the Independent Qualified Reserves Evaluator.

Finally, 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, 2017

Deep Basin (Consolidated Entities)

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

Production in 2017 averaged 5,782 boe/d (89% gas). Harvest saw significant production growth in production volumes during 2017 as the result of increased capital investment tied to expanded processing and transportation agreements.

Legacy production is from vertical wells completed in multiple zones (Falher, Cardium, Cadotte, Cadomin, Bluesky, Dunvegan, and Gething) and comingled together. Recent drilling activities have been focused on drilling high rate, 5 to 10 MMcf/d, multi-stage stimulated horizontal wells in the Falher formation. In 2017, Harvest participated in three partner operated horizontal multi-stage fractured wells (1.6 net) in the Deep Basin area. Total capital investment in Deep Basin was approximately $16.5 million in 2017 and primarily related to drilling and facilities.

Deep Basin Partnership (Equity Investment)

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

Production for 2017 in the DBP averaged 5,779 boe/d, and Harvest's equity interest in the production was 4,769 boe/d. During 2017, DBP participated in one gross partner-operated (0.2 net) well in the Deep Basin, targeting the Fahler formation. The DBP also completed and tied in three 100% DBP working interest Montney wells in Q1 2017 that were drilled in 2016. Production from the DBP's wells is primarily directed to the Harvest-operated Harvest-KERR Midstream Partnership gas plant. The total capital programs by the two partnerships in 2017 was $11.4 million in the DBP and $1.0 million in the Harvest Kerr Midstream Partnership.

Royce

Royce is comprised of operated and non-operated oil and gas properties north of Grande Prairie Alberta.

Production in Royce averaged 2,382 boe/d. Production from this area consists primarily of 25° to 39° API crude oil from the Slave Point, Kiskatinaw, Dunvegan, Spirit River, Belloy, Baldonnel, and Gething formations.

In 2017, Harvest drilled seven horizontal wells in the Royce area targeting light oil in the Charlie Lake formation. Harvest's total Royce capital program in 2017 was $20.7 million which consisted of drilling, facilities, workovers, and major equipment overhauls.

Loon

Loon is located 200 miles north west of Edmonton, Alberta. Production in 2017 from Loon averaged 2,100 boe/d (94% oil), with an average oil quality of 37° to 39° API from the Slave Point, Granite Wash and Gilwood formations.

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

Harvest did not drill any wells at Loon for the year ended December 31, 2017. Our total Loon capital program in 2017 was $3.4 million, and was primarily focused on recompletions, capital maintenance, and workovers.

Rocky Mountain House

Rocky Mountain House is comprised of properties west of Highway 2, south of Edmonton and north of Calgary. This is primarily a liquids-rich natural gas production area with some oil production. Production in 2017 for the region averaged 8,374 boe/d (65% gas).

Gas and oil gathering, transportation, compression and processing infrastructure is extensive in Rocky Mountain House and Harvest uses a combination of Harvest and third-party infrastructures to process and transport its gas, oil and NGLs to market.

Major fields in this area include Willesden Green (liquid rich gas from Glauconite formation), Ferrier (Cardium Oil), Rimbey (production from the Glauconite, Ostracod, Notikewin and Cardium formations), Caroline (Beaverhill Lake liquids rich 50% H_2S gas), Crossfield (Ellerslie oil and Basal Quartz gas), and Markerville (Pekisko, Edmonton Sands, Cardium and Glauconite and Ellerslie). The significant majority of new drilling is multi-stage stimulated horizontal wells targeting liquid rich Glauconite gas or Cardium oil.

In 2017, Harvest drilled two (1.1 net) wells in the Rocky Mountain house area including one operated multi-stage horizontal well targeting gas and natural gas liquids in the Glauconitic formation and one partner operated horizontal multi-stage well targeting oil in the Cardium formation. Total capital expenditures throughout the area were approximately $7.1 million mainly associated with drilling, major equipment overhauls, and workovers.

Hay River

Hay River was acquired by Harvest on August 2, 2005 and is located approximately 245 miles north west of Grande Prairie in north-eastern British Columbia. In 2017, Hay River produced an average of 3,722 boe/day of 24^{o} API crude oil from the Bluesky formation located at a depth of approximately 1150 feet (350 metres).

Since 2007, Harvest has focused on increasing water injection into the producing Bluesky formation to improve overall pressure support and recovery of oil from the reservoir. The reinjection of produced water is now being augmented with additional make-up water from the Gething formation. A gas plant constructed in 2007 was commissioned in the spring of 2008 to eliminate flaring at the site and to manage recovery and reinjection of associated gas. Connection of commercial power to the site was also completed in 2008 which allowed for optimization of the production in the field. 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 and workover 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, however blending downstream prior to sales contributes to stronger netbacks when compared to other similar gravity crudes. Harvest has a 100% working Interest in this operated property. In 2017, Harvest did not drill any wells in this area. The Hay capital program for 2017 was $10.4 million, and primarily focused on workovers, enhanced recovery and capital maintenance.

East Central Alberta

This area mainly encompasses legacy oil properties from the Saskatchewan / Alberta border to Alberta Highway 2 and between the cities of Edmonton and Calgary. Working interest in these properties is generally over 90%. In 2017, the average production was 1,175 boe/d (83% oil) and is primarily heavy and medium oil from 18^{o} to 32^{o} API. The Corporation's largest group of legacy properties includes Bellshill and several smaller oilfields in the surrounding area. This area remains largely focused on cost savings and optimization of current wells and facilities. Harvest continues to invest in pipeline and infrastructure upgrades to repair or replace some of the older equipment in East Central Alberta. Harvest drilled no wells in 2017 in East Central Alberta.

Total capital investment in East Central Alberta was approximately $1.3 million in 2017 primarily related to capital maintenance and major equipment overhauls.

Heavy Oil

Harvest has various working interests in this area, which is located near the town of Lloydminster on the Alberta side of the border and down into Southern Alberta near the city of Medicine Hat. Major properties in this group include Suffield which produces from the Glauconite formation, Lindbergh/Wildmere which produces from the Lloyd/Sparky/GP formations, and Hayter which has production from the Dina, Cummings and Sparky formations.

Production is 12° to 15° API heavy crude oil and averaged 2,728 boe/d (93% oil) in 2017. Production from these wells generally goes to central processing facilities with solution gas conservation and oil is trucked to third party sales points, except for Hayter and Suffield which are pipeline connected.

Harvest did not drill any wells in this area in 2017. Harvest's capital budget in Heavy Oil was focused on capital maintenance and major equipment overhauls with total net capital expenditures of $1.5 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 2015, construction had been completed on well pads and connecting pipelines, and several systems were commissioned. Construction activities were recommenced in the fourth quarter of 2017. Commissioning and first steam injection is expected to be completed in the second quarter of 2018, with first production anticipated in the third quarter of 2018.

Phase 1 will inject steam for several months and then begin oil production, ramping up to a targeted rate of 10,000 boe/d in approximately 18 months. Phase 2 of the project, which is targeted to increase production capacity to 30,000 bbl/d, received all required regulatory approvals in 2013.

Total capital expenditures of $4.6 million were incurred in 2017 relating to construction and preliminary commissioning costs on the central processing facility.

Oil and Gas Wells

The following table sets forth the number of oil and gas wells in which Harvest's Consolidated Entities held a Working Interest at December 31, 2017:

	Oil Wells				**Natural Gas Wells**			
	Producing		Non-Producing(1)		Producing		Non-Producing(1)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,293	954	1,984	1,553	1,063	388	956	404
British Columbia	400	381	185	112	51	9	97	42
Total	1,693	1,335	2,169	1,665	1,114	397	1,053	446

(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.

All of Harvest's oil and gas wells are onshore.

Developed Non-Producing Reserves

The following table outlines reserves associated to each principal property in which the associated wells are capable of producing, but are currently not producing:

	Developed Non-Producing		
	Net Hectares with Rights Expiring Within One Year	Gross (Mmboe)	Net (MMboe)
Rocky Mountain House		1.4	1.3
East Central		0.5	0.5
Royce		1.0	0.9
Hay River		0.2	0.1
Deep Basin		0.6	0.5
Loon		0.5	0.5
Heavy Oil		1.1	0.9
Other		0.1	0.2
Total		5.4	4.9

The wells associated to the above reserves were shut-in over the last 1 to 15 years. All wells designated as Developed Non-Producing are proximal to pipeline access, and therefore have access to a market when put back on production.

Properties with No Attributed Reserves

The following tables set out Harvest Consolidated Entities' undeveloped land holdings as at December 31, 2017:

	Unproved Properties (Hectares)(1)		
	Gross	Net	Net Hectares with Rights Expiring Within One Year
Alberta	201,384	141,515	7,179
British Columbia	86,164	54,583	0
Total	287,548	196,098	7,179

(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

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 2017 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 and Harvest's actual experience with abandoning similar wells in each area. 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 costs (excluding salvage values) and well site reclamation costs 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.

Tax Horizon

Harvest anticipates that there will be no cash income tax payable prior to 2048. 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 Harvest's Consolidated Entities and Equity Investment for the year ended December 31, 2017:

	Consolidated Entities			**Equity Investment**
($ millions)	Oil & Gas Capital Expenditures (Excluding Oil Sands)	Oil Sands Capital Expenditures	Total Capital Expenditures(1)(2)	Oil & Gas Capital Expenditures
Exploration costs	—	—	—	—
Development costs	65.3	4.6	69.9	9.4
Total	65.3	4.6	69.9	9.4

(1) Total capital expenditures of $9.4million represents Harvest's 82.59% portion of the $11.4 million gross capital expense of the Deep Basin Partnership

(2) Total capital expenditures exclude head office assets of $0.3 million

Exploration and Development Activities

The following table sets forth the number of Exploratory and Development Wells completed by Harvest's Consolidated Entities during 2017:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil Wells	2.0	2.0	6.0	5.1
Gas Wells	—	—	4.0	2.6
Total Wells	2.0	2.0	10.0	7.7

2018 Capital Expenditure Plan

The primary areas of focus for Harvest's Conventional and Oil Sands capital program during 2018 are the following:

- BlackGold – Complete Pad & CPF facilities; complete commissioning activities; circulate SAGD well Pairs, convert wells to production mode and optimize overall asset performance.
- Deep Basin Area – Participate in approximately five non-operated drilling and/or completions and tie-ins.

- Deep Basin Partnership – Drill two 100% DBP Montney liquids rich gas wells and participate in 3 partner operated Falher wells.
- Royce – Complete and tie-in two operated wells in that were drilled in 2017. Drill, complete and tie-in approximately four additional operated wells throughout 2018 with all but one coming on production in 2018.
- Loon – One horizontal multi-stage stimulated well in the non-unit area that spudded in December 2017 will be completed and tied in with a possible follow up to be drilled in Q4 2018. Four additional vertical wells will be drilled within the unit to increase oil recovery. These wells will start drilling in late 2018 with the program carrying over into Q1 2019.
- Rocky Mountain House – Drill approximately two operated Glauconite liquid rich wells and participate in several non-operated Cardium wells.
- Hay River – Optimize existing production by cleaning out some wellbores. Perform injection stimulations to increase sweep efficiency.

Incremental Exploitation and Development Potential

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

- Implementation or optimization of enhanced water floods in selected pools such as Hay River, Royce, and Loon resulting in increased production and recovery;
- Uphole completions of bypassed or untested reserves in existing wellbores, including recompletion of existing shut-in wells to access undrained reserves;
- Selected infill and step-out development drilling opportunities across most of Harvest’s core properties for various proven targets generally defined by 3-D seismic;
- Numerous exploratory opportunities defined by seismic from which value might be extracted by sale, farmout or joint venture;
- Management of dry gas and high operating cost wells currently shut in due to low commodity prices to preserve reserves to be produced at a time when prices improve; and
- Utilizing multistage fractured technology in horizontal wells to increase oil recovery from tight oil and gas formations at Loon (Slave Point Formation), Deep Basin (Falher and Montney Formations) and Rocky Mountain House (Cardium, Glauconite, Viking, Ostracod, Notikewin, Wilrich Formations).

Production Estimates

The following table sets forth the forecast volume of production from gross reserves for Harvest's Consolidated Entities' per the 2017 year-end Reserves Report:

	2018 Production Forecast Before Royalty Interests						
	Light and Medium	Heavy Oil	Bitumen	Conventional Natural Gas	Coal Bed Methane	Natural Gas Liquids	Total (1)
	bbl/d	bbl/d	bbl/d	mcf/d	mcf/d	bbl/d	boe/d
Proved Producing	7,453	2,477	—	62,020	32	2,781	23,053
Proved Developed Non-Producing	283	325	—	2,275	—	153	1,140
Proved Undeveloped	138	—	652	13,516	—	483	3,526
Total Proved	7,874	2,802	652	77,811	32	3,417	27,719
Total Probable	611	296	8	5,455	—	184	2,008
Total Proved Plus Probable	8,485	3,098	660	83,266	32	3,601	29,727

(1) Rocky Mountain House 2018 production forecast before royalties on a gross proved and gross probable basis are 9,538 boe/d and 397 boe/d respectively. Deep Basin Group's production forecast before royalties on a gross proved and gross probable basis are 6,181 boe/d and 595 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 for Harvest's Consolidated Entities indicated below:

	Average Daily Production Volumes				
	2017				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil (bbl/d)	3,855	3,890	3,950	4,102	4,039
Heavy Oil (bbl/d)	7,765	7,324	7,111	6,754	7,147
Total Oil (bbl/d)	11,620	11,214	11,061	10,856	11,186
NGLs (bbl/d)	3,467	2,828	3,115	3,667	3,269
Natural Gas(mcf/d)	72,828	73,685	76,417	68,276	72,799
Total Daily Production (boe/d)	27,226	26,324	26,912	25,902	26,588

	Total Sales Production				
	2017				
	Q1	Q2	Q3	Q4	Total
Light and Medium Oil (MMbbl)	0.4	0.4	0.4	0.4	1.6
Heavy Oil (MMbbl)	0.7	0.6	0.6	0.6	2.5
Total Oil (MMbbl)	1.1	1.0	1.0	1.0	4.1
NGLs (MMbbl)	0.3	0.3	0.3	0.3	1.2
Natural Gas (Bcf)	6.6	6.7	7.0	6.3	26.6
Total Production (MMboe)	2.4	2.4	2.5	2.4	9.7

	Average Sales Prices Received				
	2017				
	Q1	Q2	Q3	Q4	Total
Light & Medium oil ($/bbl)	57.98	55.82	50.54	62.72	56.69
Heavy Oil ($/bbl)	47.17	47.90	43.30	52.98	47.72
Total Oil ($/bbl)	50.75	50.65	45.89	56.66	50.96
NGLs ($/bbl)	37.38	25.00	33.77	41.63	35.04
Natural Gas ($/mcf)	2.96	3.03	1.63	1.78	2.35
Total ($/boe)	34.91	33.59	27.80	35.15	32.83

	Royalties Paid				
	2017				
	Q1	Q2	Q3	Q4	Total
($ millions)					
Light & Medium Oil	2.8	3.8	1.5	2.8	10.9
Heavy Oil	2.9	3.4	2.8	2.8	11.9
NGLs	1.1	1.1	1.5	1.5	5.2
Natural gas	1.5	2.9	-	0.8	5.2
Total	8.3	11.2	5.8	7.9	33.2
Light & Medium Oil ($/bbl)	7.00	9.50	3.75	7.00	6.81
Heavy Oil ($/bbl)	4.14	5.67	4.67	4.67	4.76
NGLs (S/bbl)	3.67	3.67	5.00	5.00	4.33
Natural gas ($/boe)	1.36	2.60	-	0.76	1.17
Total ($/boe)	3.40	4.67	2.33	3.32	3.42

	Operating Expenses				
	2017				
	Q1	Q2	Q3	Q4	Total
($ millions)					
Light & Medium Oil	8.9	8.6	7.9	7.7	33.1
Heavy Oil	15.2	10.8	9.6	11.7	47.3
NGLs	4.1	3.8	3.2	4.0	15.1
Natural gas	10.2	12.4	13.0	12.4	48.0
Total	38.4	35.6	33.7	35.8	143.5
Light & Medium Oil ($/bbl)	22.25	21.50	19.75	19.25	20.69
Heavy Oil ($/bbl)	21.71	18.00	16.00	19.50	18.92
NGLs ($/boe)	13.67	12.67	10.67	13.33	12.58
Natural Gas ($/boe)	9.27	11.10	11.14	11.81	10.83
Total ($/boe)	15.67	14.82	13.59	15.04	14.79

	Netback Received(1)(2)				
	2017				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($/bbl)	28.73	24.82	27.04	36.47	29.19
Heavy Oil ($/bbl) (1)	21.32	24.23	22.63	28.81	24.04
NGLs ($/bbl)	20.04	8.66	18.10	23.30	18.13
Natural Gas ($/boe) (1)	7.13	4.48	(1.36)	(1.89)	2.10
Total ($/boe)	15.84	14.10	11.88	16.79	14.62

(1) Netbacks are calculated as revenues subtracted by operating expenses and royalties. Netbacks exclude miscellaneous income not related to oil and gas production.

(2) These are non-GAAP measures. Please refer to “Non-GAAP Measures” section.

2017 Historical Production by Material Area for Harvest's Consolidated Entities

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	—	3,707	—	15	3,722
Loon	1,982	—	411	49	2,100
Rocky Mountain House	462	84	32,509	2,409	8,374
East Central Alberta	772	204	1,013	30	1,175
Deep Basin	21	—	30,934	605	5,782
Heavy Oil	—	2,535	830	55	2,728
Royce	790	617	5,264	99	2,382
Other	12	—	1,838	7	325
Total	4,039	7,147	72,799	3,269	26,588

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;
- tax horizon;
- expected abandonment and reclamation costs; 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
- 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, 2017.

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, operating expenses, and royalties. Netbacks exclude miscellaneous income not related to oil and gas production. 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 – HARVEST OPERATIONS CORP.

To the Board of Directors of Harvest Operations Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. 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 principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction 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 for the year ended December 31, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

				Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) ($ millions)			
Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Description	Location of Reserves	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	December 31, 2017	Harvest Operations Corp.	Canada	-	1,052	-	**1,052**

6. 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.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after their respective preparation dates.

8. 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:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, January 23, 2018

(Signed) “Myron J. Hladyshevsky”, P. Eng.

Vice President

FORM 51-101F2: REPORT ON RESERVES DATA AND CONTINGENT RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR – HARVEST OPERATIONS CORP.

To the Board of Directors of Harvest Operations Corp. (the "Company"):

1. We have evaluated the Company's reserves data and contingent resources data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2017, estimated using forecast prices and costs.

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

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

5. The following table shows the net present value of future net revenue (before deduction 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 for the year ended December 31, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

				Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) ($ millions)			
Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Description	Location of Reserves	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	December 31, 2017	BlackGold	Canada	-	912	-	**912**

6. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Company's board of directors:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Description	Location of Reserves	Risked Volume (Mboe)	Risked Net Present Value of Future Net Revenue (before income taxes,10% discount rate) ($ millions) Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants Ltd.	December 31, 2017	BlackGold	Canada	23,615	-	18.5	**18.5**

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

8. We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our reports referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, January 23, 2018

(Signed) “William M. Spackman”, P. Eng.

Manager, Engineering

FORM 51-101F2: REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR – DEEP BASIN PARTNERSHIP

To the Board of Directors of Harvest Operations Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. 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 principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction 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 for the year ended December 31, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Company's 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 Effective Date of Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	Deep Basin Partnership (HOC interest) December 31, 2017	Canada	-	128	-	**128**

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

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our reports referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, January 23, 2018

(Signed) “Myron J. Hladyshevsky”, P. Eng.

Vice President

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, 2017, 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)
Sungki Lee
Acting President & Chief Executive Officer

(Signed)
Jim Causgrove
Chief Operating Officer, Conventional Assets

(Signed)
Paul Vander Valk
Chief Operating Officer, Oil Sands

(Signed)
Allan Buchignani
Director

(Signed)
Richard Kines
Director

March 28, 2017