PETRO VIKING ENERGY INC.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

(COMPLYING WITH FORM 51-101F1)

EFFECTIVE DATE (as at fiscal yearend): DECEMBER 31, 2013

April 30, 2014

Definitions, Notes and Other Cautionary Statements

Abbreviations, Terms and Conversions

Certain terms and abbreviations used in this statement of reserves data and other information are defined below:

"Bbl"	barrel of oil or NGL;
"bcf"	billion cubic feet of natural gas;
"boe"	barrel of oil equivalent determined by converting (i) a volume of natural gas to barrels of oil using the ratio of 6 mcf to one barrel and (ii) a volume of NGLs to barrels of oil using the ratio of one barrel of NGLs to one barrel of oil; this conversion is not based on either energy content or prices;
"boepd"	barrel of oil equivalent per day;
"bpd"	barrel of oil or NGL per day;
"mbbl"	thousand barrels;
"mboe"	thousand barrels of oil equivalent;
"mmbtu"	million British Thermal Units;
"Mcf"	thousand cubic feet of natural gas;
"Mcfd"	thousand cubic feet of natural gas per day;
"MMcf"	million cubic feet of natural gas;
"MMcfd"	million cubic feet of natural gas per day;
"MSTB"	thousand stock tank barrels;
"NGL"	natural gas liquids;

In this statement of reserves data and other information, measurements are given in standard Imperial or metric units only. The following table sets forth certain standard conversions.

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbl	cubic metres	0.159
cubic metres	Bbl	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

Unless otherwise indicated, the following definitions and other notes are applicable.

1. ***"Gross"*** means:

   (a) in relation to PETRO VIKING ENERGY INC.'s ("the Company") interest in production and reserves, its "gross revenues", which are the Company's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company;

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

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

2. ***"Net"*** means:

(a) in relation to the Company's interest in production and reserves, its "net reserves", which are the Company's interest (operating and non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production of reserves;

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

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

3. *Definitions used for reserve categories are as follows:*

"Reserves" are 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, which are generally accepted as being reasonable.

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.

Development and Production Status

Each of the reserve categories (proved and probable) 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 (for example, 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.

(i) **"*Developed producing reserves*"** are those reserves that are expected to be recovered from completion intervals open 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.

(ii) **"*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 (for example, 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) 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 estimator'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.

Levels of Certainty for Reported Reserves

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:

- At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- At least a 50 percent probability that the quantities 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.

4. *Forecast prices and costs*

"*Future prices and costs*" that are**:**

(a) Generally acceptable as being a reasonable outlook of the future; and

(b) If and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company 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 and costs referred to in paragraph (a).

5. *Future income tax expense*

"*Future income tax expenses*" are estimated**:**

(a) Making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes;

(b) Without deducting estimated future costs that are not deductible in computing taxable income;

(c) Taking into account estimated tax credits and allowances; and

(d) Applying to the future pre-tax net cash flows relating to the Company's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

6. "***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 location horizon known to be productive.

7. "***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 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 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 processing plants, and central utility and waste disposal systems; and

(d) Provide improved recovery systems.

8. "***Exploration well***" means a well that is not a development well, a service well or a stratigraphic test well.

9. "***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 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 crews and others conducting those studies;

   (b) Costs of carrying and retaining unproved properties, such as delay 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.

10. "***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.

11. Numbers may not add due to rounding.

12. The estimates of future net revenue presented do not represent fair market value.

13. Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

14. Estimated future abandonment and reclamation costs related to a property have been taken into account by McDaniel & Associates Consultants Ltd. in determining reserves that should be attributable to a property and in determining the aggregate future net revenue there from, there was deducted the reasonable estimated future well abandonment costs.

15. Forecast price and cost assumptions assume the continuance of current laws and regulations.

16. The extended character of all factual data supplied to **McDaniel & Associates Consultants Ltd.** were accepted by them as represented. No field inspection was conducted

Form 51-101F1

PETRO VIKING ENERGY INC. ("the Company")

STATEMENT OF RESERVE DATA AND OTHER OIL AND GAS INFORMATION
April 30, 2014

PART 1

RELEVANT DATES

The effective date of the information being provided in this statement is December 31, 2013. The preparation date of the information being provided in this statement is April 30, 2014. For a glossary of terminology and definitions relating to the information included in this report, readers are referred to National policy Instrument 51-101 "Standards for Disclosure for Oil and Gas Activities" ("NI 510101").

RESERVES AND FUTURE NET REVENUE

The following is a summary of the oil and natural gas reserves and the net present values of future net revenue of PETRO VIKING ENERGY INC. as evaluated by **McDaniel & Associates Consultants Ltd.** of Calgary Alberta Report dated April 2, 2014. **McDaniel & Associates Consultants Ltd**. are independent qualified reserves evaluators appointed by the Company pursuant to NI 51-101. McDaniel & Associates Consultants Ltd. independently evaluated all of the Company's Oil and Gas properties.

The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and costs assumptions contained in the McDaniel & Associates Consultants Ltd.'s report will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the McDaniel & Associates Consultants Ltd.'s report. The recovery and reserves estimates attributed to the Company's properties described herein are estimates only. The actual reserves attributable to the Company's properties may be greater or less than those calculated.

PART 2 – DISCLOSURE OF RESERVE DATA

All of the Company's properties, reserves and production are located in Canada in the provinces of Alberta, Saskatchewan and Ontario.

The following tables detail the aggregate gross and net reserves of the Company, as at December 31, 2013, using forecast prices and costs as well the aggregate net present value of future net revenue undiscounted and discounted at 5%, 10%, 15% and 20%:

TOTAL COMPANY RESERVES AND NET PRESENT VALUE
FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2013

	Company Share of Remaining Reserves			**Company Share of Net Present Value Before Income Tax (M$) (5)**				
	(Mbbl, Mmcf, Mlt)							
	GROSS (1)	**R.I. (2)**	**NET (3)**	**@ 0.00%**	**@ 5.0%**	**@ 10.0%**	**@ 15.0%**	**@ 20.0%**
Proved Reserves								
Light and Medium Oil	34.1	0.1	31.1	944.6	856.2	780.9	717.8	664.8
Natural Gas	331.8	0.3	298.3	184.3	192.2	185.4	174.2	162.3
Natural Gas Liquids	11.5	-	8.0	474.2	367.6	298.1	250.3	215.8
				1,603.0	**1,415.9**	**1,264.4**	**1,142.3**	**1024.9**
Probable Reserves								
Light and Medium Oil	8.4	-	7.5	265.9	199.3	154.2	123.0	100.9
Natural Gas	101.0	0.1	90.4	84.5	76.7	62.4	49.8	39.9
Natural Gas Liquids	3.7	-	2.6	170.6	91.4	54.1	34.8	23.9
				521.1	**367.4**	**270.7**	**207.6**	**164.8**
Total Proved and Probable Reserves								
Light and Medium Oil	42.4	0.2	38.6	1,210.5	1,055.5	935.1	840.8	765.7
Natural Gas	432.8	0.3	388.7	268.8	268.9	247.9	224.0	202.2
Natural Gas Liquids	15.2	-	10.6	644.9	459.0	352.2	285.0	239.8
				2,124.1	**1,783.3**	**1,535.2**	**134.9**	**1207.7**

(1) Gross reserves are working interest reserves before deductions
(2) Royalty interest reserves
(3) Net reserves working interest after royalty deductions plus royalty interest reserves
(4) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.0:1 for Condensate and C5+, 1.0:1 for Ethane, 1.0:1 for Propane, 1.0:1 for Butanes, 1.0:1 for NGL Mix. NVP/BOE based on Company Share BOE reserves. BOE's 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.
(5) Costs associated with extraction of natural gas products have in most cases been deducted from the natural gas revenues

TOTAL COMPANY RESERVES AND NET PRESENT VALUE
FORECAST PRICES AND COSTS AS OF DECEMBER 31 2013

	Company Share of Remaining Reserves (MBOE)			**Company Share of Net Present Value Before Income Tax ($/BOE)**				
	Gross (1)	**R.I. (2)**	**Net (3)**	**@ 0.00%**	**@ 5.0%**	**@ 10.0%**	**@ 15.0%**	**@ 20.0%**
Proved Reserves	100.9	0.2	88.8	15.87	14.02	12.52	11.31	10.32
Probable Reserves	28.9	-	25.2	17.99	12.68	9.34	7.17	5.69
Total Proved and Probable Resources	**129.8**	**0.2**	**114.0**	**16.34**	**13.72**	**11.81**	**10.38**	**9.29**

	Company Share of Net Present Value After Income Tax (M$)				
	@ 0.00%	**@ 5.0%**	**@ 10.0%**	**@ 15.0%**	**@ 20.0%**
Proved Reserves	1,603.0	1,415.9	1,264.4	1,142.3	1,042.9
Probable Reserves	446.3	317.9	236.9	183.9	147.7
Total Proved and Probable Resources	**2,049.3**	**1,733.8**	**1,501.4**	**1,326.2**	**1,190.6**

The following tables provide a breakdown of various elements of future net revenue attributable to proved reserves and proved plus probable (in total) of the Company estimated using forecast prices and costs and calculated without discount :

NET PRESENT VALUES OF FUTURE NET REVENUE
FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2013
TOTAL OF ALL AREAS

	Before Income Taxes (Discounted at (%/year)					**After Income Taxes (Discounted at (%/year)**				
	@ 0.0% (MM$)	@ 5.0% (MM$)	@ 10.0% (MM$)	@ 15.0% (MM$)	@ 20.0% (MM$)	@ 0.0% (MM$)	@ 5.0% (MM$)	@ 10.0% (MM$)	@ 15.0% (MM$)	@ 20.0% (MM$)
Reserve Classification										
Proved	1.6	1.4	1.3	1.1	1.0	1.6	1.4	1.3	1.1	1.0
Probable	0.5	0.4	0.3	0.2	0.2	0.4	0.3	0.2	0.2	0.1
Total Proved and Probable	**2.1**	**1.8**	**1.5**	**1.3**	**1.2**	**2.0**	**1.7**	**1.5**	**1.3**	**1.2**

UNDISCOUNTED FUTURE NET REVENUE
FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2013
TOTAL OF ALL AREAS

	Sales Revenue (1) M$	**Royalties (2)** M$	**Operating Costs** M$	**Total Development Costs** M$	**Total Abandonment Costs** M$	**Future Net Revenue Before Tax** M$	**Income Taxes** M$	**Future Net Revenue After Tax** M$
Reserve Classification								
Proved	5,279.0	644.0	2,784.0	-	248.0	1,603.0	-	1,603.0
Probable	1,636.0	223.0	884.0	-	8.0	521.0	75.0	443.0
Total Proved and Probable	**6,915.0**	**867.0**	**3,668.0**	**-**	**256.0**	**2,124.0**	**75.0**	**2,049.0**

(1) Sales Revenue includes all non-producing income
(2) Royalties includes any net profits interests paid as well as the Saskatchewan Corporation Capital Tax Surcharge

The following table details by production group the net present value of future net revenue (before deducting future income tax expenses) estimated using forecast prices and costs and calculated using undiscounted and discount rates of 10% and 15%.

OIL AND GAS AND NET PRESENT VALUES BY PRODUCTION GROUP
FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2013
TOTAL COMPANY

	Oil Light and Medium		Natural Gas		Natural Gas Liquids		NPV of Future Net Revenue Before Income Taxes (4)			Unit	
	Gross	Net	Gross	Net	Gross	Net	0.0%	10.0%	15.0%	Value (2)	BOEs (3)
	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(M$)	(M$)	(M$)	$/bbl $/Mcf	Value Conversion
Light and Medium Oil (Inclduing Associated Gas and Byproducts)											
Proved Developed Producing	34.0	31.0	-	-	-	-	945.0	781.0	718.0	25.12	-
Proved Non-Producing	-	-	-	-	-	-	-	-	-	-	-
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-	-
Total Proved	34.0	31.0	-	-	-	-	945.0	781.0	718.0	25.12	-
Total Probable	8.0	8.0	-	-	-	-	266.0	154.0	123.0	20.48	-
Total Proved plus Probable	**42.0**	**39.0**	**-**	**-**	**-**	**-**	**1,211.0**	**935.0**	**841.0**	**24.22**	**-**
Non-Associated Gas (Including Byproducts)											
Proved Developed Producing	-	-	332.0	298.0	12.0	8.0	658.0	483.0	424.0	1.62	15.50
Proved Non-Producing	-	-	-	-	-	-	-	-	-	-	-
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-	-
Total Proved	-	-	332.0	298.0	12.0	8.0	658.0	483.0	424.0	1.62	15.50
Total Probable	-	-	101.0	90.0	4.0	3.0	255.0	116.0	85.0	1.29	15.90
Total Proved plus Probable	**-**	**-**	**433.0**	**389.0**	**15.0**	**11.0**	**913.0**	**600.0**	**509.0**	**1.54**	**15.7**

(1) Gas reserves included in Light, Medium and Heavy Oil are Solution Gas reserves only
(2) Unit values are calculated using the 10% discount rate divided by the Major Product Type Net reserves for each group
(3) BOEs are calculated by dividing the unit values of Light and Medium Oil reserves by the unit values of the other major product type reserves for each reserve classification. This results in BOEs calculated on a value basis.

PART 3 – PRICING ASSUMPTIONS

The following tables detail the benchmark reference prices for the regions in which the Company operated as at December 31, 2013 reflected in the reserves data disclosed above under "Disclosure of Reserves Data". These pricing assumptions were provided by **McDaniel & Associates Consultants Ltd.**, an independent qualified reserves evaluator and auditor.

SUMMARY OF PRICE FORECAST - OIL AND NATURAL GAS LIQUIDS
JANUARY 1, 2014

								Edmonton				
Year	WTI Crude Oil $US/bbl	Brent Crude Oil $US/bbl	Edmonton Light Crude Oil $C/bbl	Alberta Bow River Hardisty Crude Oil $C/bbl	Western Canadian Select Crude Oil $C/bbl	Alberta Heavy Crude Oil $C/bbl	Sask Cromer Medium Crude Oil $C/bbl	Cond. & Natural Gasolines $/bbl	Propane $/bbl	Butanes $/bbl	Inflation %	US/CAN Exchange Rate $US/$CAN
	(1)	(2)	(3)	(4)	(5)	(6)	(7)					
History												
2000	30.31	28.40	44.72	34.35		27.80	40.10	46.25	31.55	35.00	2.7	0.674
2001	25.97	24.42	39.60	25.07		18.05	32.22	42.44	29.15	28.45	2.6	0.646
2002	26.10	24.95	39.95	31.65		27.60	34.93	40.79	19.85	26.10	2.2	0.637
2003	31.05	28.85	43.15	32.68		27.40	37.57	44.19	30.15	33.45	2.0	0.716
2004	41.40	38.30	52.54	37.60	36.14	30.40	45.94	54.09	33.28	39.45	2.0	0.770
2005	56.56	54.48	68.72	44.83	44.60	34.35	57.47	69.63	43.29	52.58	2.1	0.826
2006	66.23	65.20	72.80	51.55	51.22	43.14	61.25	75.06	44.05	60.10	2.2	0.880
2007	72.30	72.80	76.35	53.25	52.90	44.63	65.40	77.36	49.45	63.75	2.0	0.935
2008	99.60	97.80	102.20	84.30	82.94	75.55	93.20	104.75	58.40	75.25	2.4	0.943
2009	61.80	61.60	65.90	60.30	58.58	55.30	62.80	68.15	38.60	49.25	2.0	0.880
2010	79.50	79.90	77.50	68.50	67.23	61.45	73.80	84.25	46.70	66.05	2.0	0.971
2011	95.10	111.25	95.00	78.55	77.10	67.90	88.90	104.20	55.15	76.50	2.0	1.012
2012	94.20	111.65	86.10	74.35	73.08	63.65	82.10	100.80	28.60	69.55	2.0	1.000
2013	97.90	108.30	92.70	76.40	75.15	65.75	88.45	104.35	38.85	68.60	2.0	0.971
Forecast												
2014	95.00	105.00	95.00	77.90	76.50	67.50	89.30	102.50	50.20	76.60	2.0	0.950
2015	95.00	102.50	96.50	81.10	79.60	70.40	90.70	101.60	50.50	77.80	2.0	0.950
2016	95.00	100.20	97.50	81.90	80.40	71.20	91.70	100.60	50.60	78.60	2.0	0.950
2017	95.00	97.70	98.00	82.30	80.90	71.50	92.10	101.20	51.30	79.00	2.0	0.950
2018	95.30	98.00	98.30	82.60	81.10	71.80	92.40	101.50	52.00	79.20	2.0	0.950
2019	96.60	99.40	99.60	83.70	82.20	72.70	93.60	102.90	53.20	80.30	2.0	0.950
2020	98.50	101.30	101.60	85.30	83.80	74.20	95.50	105.00	54.10	81.90	2.0	0.950
2021	100.50	103.40	103.60	87.00	85.50	75.60	97.40	107.00	55.20	83.50	2.0	0.950
2022	102.50	105.40	105.70	88.80	87.20	77.20	99.40	109.20	56.30	85.20	2.0	0.950
2023	104.60	107.60	107.90	90.60	89.00	78.80	101.40	111.50	57.40	87.00	2.0	0.950
2024	106.70	109.70	110.00	92.40	90.80	80.30	103.40	113.70	58.50	88.60	2.0	0.950
2025	108.80	111.90	112.20	94.20	92.60	81.90	105.50	115.90	59.80	90.40	2.0	0.950
2026	111.00	114.20	114.50	96.20	94.50	83.60	107.60	118.30	61.00	92.30	2.0	0.950
2027	113.20	116.40	116.70	98.00	96.30	85.20	109.70	120.60	62.20	94.00	2.0	0.950
2028	115.50	118.80	119.10	100.00	98.30	86.90	112.00	123.10	63.50	96.00	2.0	0.950
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.950

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API/0.5% sulphur
(2) North Sea Brent Blend 37 degrees API/1.0% sulphur
(3) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
(4) Bow River at Hardisty Alberta (Heavy stream)
(5) Western Canadian Select at Hardisty, Alberta
(6) Heavy crude oil 12 degrees API at Hardisty Alberta (after deduction of blending costs to reach pipeline quality)
(7) Midale Cromer crude oil 29 degrees API, 2.0% sulphur

SUMMARY OF NATURAL GAS PRICE FORECASTS
JANUARY 2014

Year	U.S. Henry Hub Gas Price $US/MMBtu	Alberta AECO Spot Price $C/MMBtu	Alberta Average Plantgate $C/MMBtu	Alberta Aggregator Plantgate $C/MMBtu	Alberta Spot Sales Plantgate $C/MMBtu	Sask. Prov. Gas Plantgate $C/MMBtu	Sask. Spot Sales Plantgate $C/MMBtu	British Columbia Average Plantgate $C/MMBtu
			(1)					
History								
2000	4.31	5.02	4.80	4.57	4.85	5.38	4.83	4.88
2001	3.98	6.30	5.90	5.25	6.10	5.25	6.15	6.30
2002	3.36	4.07	3.89	3.80	3.90	3.91	3.90	3.93
2003	5.49	6.66	6.37	6.00	6.49	6.40	6.38	6.32
2004	5.90	6.87	6.62	6.35	6.70	6.48	6.52	6.45
2005	8.60	8.58	8.43	8.48	8.42	8.35	8.58	8.12
2006	6.75	7.16	6.87	6.59	6.96	6.67	6.55	6.45
2007	6.95	6.65	6.41	6.35	6.43	6.18	6.45	6.25
2008	8.85	8.15	7.90	8.10	7.90	8.00	8.10	8.10
2009	3.95	4.20	3.95	3.90	3.95	3.85	4.05	4.05
2010	4.40	4.15	3.90	3.85	3.90	3.95	4.20	3.90
2011	4.00	3.70	3.50	3.75	3.50	3.30	3.55	3.30
2012	2.75	2.45	2.25	2.25	2.25	2.10	2.35	2.25
2013	3.70	3.20	3.00	3.00	3.00	3.05	3.10	2.90
Forecast								
2014	4.25	4.00	3.80	3.80	3.80	3.90	3.90	3.70
2015	4.50	4.25	4.05	4.05	4.05	4.15	4.15	3.95
2016	4.75	4.55	4.35	4.35	4.35	4.45	4.45	4.25
2017	5.00	4.75	4.55	4.55	4.55	4.65	4.65	4.45
2018	5.25	5.00	4.80	4.80	4.80	4.90	4.90	4.70
2019	5.50	5.25	5.05	5.05	5.05	5.15	5.15	4.95
2020	5.60	5.35	5.10	5.10	5.10	5.20	5.20	5.00
2021	5.70	5.45	5.20	5.20	5.20	5.30	5.30	5.10
2022	5.85	5.55	5.30	5.30	5.30	5.40	5.40	5.20
2023	5.95	5.65	5.40	5.40	5.40	5.50	5.50	5.30
2024	6.05	5.75	5.50	5.50	5.50	5.60	5.60	5.40
2025	6.20	5.90	5.65	5.65	5.65	5.75	5.75	5.55
2026	6.30	6.00	5.75	5.75	5.75	5.90	5.90	5.60
2027	6.45	6.15	5.90	5.90	5.90	6.05	6.05	5.75
2028	6.55	6.25	6.00	6.00	6.00	6.15	6.15	5.85
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

(1) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the crown royalty calculations

PART 4 – RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE

The following table outlines the reconciliation of changes in the Company's net remaining oil reserves estimates for the Company for the period December 31, 2012 to December 31, 2013 using forecast prices and costs:

RECONCILATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE AS OF DECEMBER 31, 2013

	Light and Medium Oil			Heavy Oil			Associated, Non-Associated and Solution Gas			Natural Gas Liquids		
	Gross Proved	Gross Probable	Gross Proved and Probable	Gross Proved	Gross Probable	Gross Proved and Probable	Gross Proved	Gross Probable	Gross Proved and Probable	Gross Proved	Gross Probable	Gross Proved and Probable
December 31, 2012	35.0	10.8	45.8	3.0	1.1	4.0	422.5	138.4	560.9	12.1	4.4	16.5
Extensions Improved Recovery												
Technical Revisions												
Discoveries												
Acquisitions												
Economic Factors												
Production	8.6	(2.5)	6.1	(2.1)	(1.1)	(3.2)	(21.6)	(37.5)	(59.1)	1.1	(0.7)	0.4
December 31, 2013	**43.6**	**8.3**	**52.0**	**0.8**	**-**	**0.8**	**400.9**	**100.9**	**501.8**	**13.2**	**3.7**	**16.9**

PART 5 – ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The proved and probable undeveloped reserves of the Company have been estimated in accordance with procedures and standards contained in the COGE Handbook. The Company's did not have any undeveloped reserves (for proved and probable) in the three most recent financial years.

Significant Factors or Uncertainties

The production rates, Oil and Gas reserves and cash flow information contained in the **McDaniel & Associates Consultants Ltd.** Report are only estimates and the actual production and ultimate reserves may be greater or less than the estimates prepared by Reliance. Factors, consideration and assumptions that the independent evaluator used to develop these estimates include, but are not limited to:

: Historical production;
: Government regulation;
: Assumptions regarding commodity prices, production, development costs, taxes and capital expenditures;
: Timing of capital expenditures;
: Effectiveness of enhanced recovery schemes;
: Marketability of production;
: Operating costs and royalties;
: Initial production rates;
: Production decline rates;
: Ultimate recovery of reserves: and
: Future oil and gas prices.

Future Development Costs

There are no future development costs for the Company's proved and probable reserves and Management does not expect any for the next five years.

The Company's petroleum and natural gas investing activities have been funded to date primarily through the issuance of common shares and expects that it will continue to be able to utilize this source of financing until it develops additional cash flow from operations.

Additional Information Concerning Abandonment and Reclamation Costs

ABANDONMENT COST
FORECAST PRICES AS OF DECEMBER 31, 2013

Province	Area	Abandonment Costs $ Per Well
Alberta	Carson Creek	30,000
	Coutts	30,000
	Farrow	30,000
	Hector	30,000
	Judy Creek	30,000
	Kaybob	30,000
	Retlaw	30,000
	Ronalane	30,000
	Westerose	30,000
Saskatchewan	Plato	30,000
Ontario	Gosfield	30,000

ABANDONMENT COSTS FORECAST (M$)
FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2013
ALL AREAS

	Total Proved		Total Proved and Probable	
Year	**Undiscounted**	**Discounted @ 10%**	**Undiscounted**	**Discounted @ 10%**
2014	-	-	-	-
2015	-	-	-	-
2016	-	-	-	-
2017	-	-	-	-
2018	-	-	-	-
2019	30.0	18.0	20.0	12.0
2020	58.0	32.0	68.0	37.0
2021	30.0	15.0	28.0	13.0
2022	18.0	8.0	3.0	1.0
2023	18.0	8.0	18.0	7.0
2024	4.0	1.0	19.0	7.0
2025	4.0	1.0	-	-
2026	-	-	8.0	2.0
2027	-	-	-	-
2028	52.0	13.0	-	-
Remaining	35.0	7.0	92.0	16.0
Total	**248.0**	**104.0**	**256.0**	**96.0**

The Company bases its estimates for the costs of abandonment and reclamation of surface leases, wells, facilities and pipelines on previous experience of management with similar well sites and facility locations. As at December 31, 2013, Within the next three (3) financial years the Company expects to spend approximately $290,000 on reclamations.

PART 6 – OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

Producing Wells

The following table summarizes the Company's interests in wells capable of production, as at December 31, 2013:

WELLS CAPABLE OF PRODUCTION

	Oil				Natural Gas			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	39.00	18.28	10.00	5.55	24.00	4.32	16.00	5.45
Saskatchewan	1.00	0.80	1.00	0.80	-	-	6.00	1.04
Ontario	1.00	0.20	-	-	-	-	-	-
Total	**41.00**	**19.28**	**11.00**	**6.35**	**24.00**	**4.32**	**22.00**	**6.49**

Remaining Reserves and Present Worth Values

The following table presents the remaining reserves and present worth values for forecast prices and costs for all areas:

UNDISCOUNTED FUTURE NET REVENUE
FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2013
TOTAL OF ALL AREAS

	Sales Revenue (1)	Royalties (2)	Operating Costs	Total Development Costs	Total Abandonment Costs	Future Net Revenue Before Tax	Income Taxes	Future Net Revenue After Tax
	M$	M$	M$	M$	M$	M$	M$	M$
Reserve Classification								
Proved	5,279.0	644.0	2,784.0	-	248.0	1,603.0	-	1,603.0
Probable	1,636.0	223.0	884.0	-	8.0	521.0	75.0	443.0
Total Proved and Probable	**6,915.0**	**867.0**	**3,668.0**	**-**	**256.0**	**2,124.0**	**75.0**	**2,049.0**

(1) Sales Revenue includes all non-producing income
(2) Royalties includes any net profits interests paid as well as the Saskatchewan Corporation Capital Tax Surcharge

Production Forecasts

The following tables shows the Company's net oil, natural gas and natural gas liquids production forecast using forecast prices and costs for the next 10 years:

TEN YEAR PRODUCTION BY AREA
FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2013

	Oil Production Forecast (Mbbl) (1)											
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Remainder	Total
Alberta												
Coutts	1.3	1.2	1.1	1.0	0.9	0.8	0.8	0.7	0.6	0.6	0.8	9.7
Farrow	1.4	1.2	1.1	1.0	0.9	0.8	0.7	0.7	0.6	0.3	-	8.7
Provost	-	-	-	-	-	-	-	-	-	-	-	0.1
Ronalane	4.6	2.8	1.9	1.6	1.0	0.8	0.2	-	-	-	-	12.8
Total	7.3	5.2	4.1	3.6	2.8	2.4	1.7	1.4	1.2	0.9	0.8	31.3
Saskatchewan												
Plato	0.6	0.4	0.1	-	-	-	-	-	-	-	-	1.1
Total	0.6	0.4	0.1	-	-	-	-	-	-	-	-	1.1
Ontario												
Gosfield	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-	1.1
Total	**8.1**	**5.8**	**4.3**	**3.8**	**2.9**	**2.5**	**1.8**	**1.5**	**1.4**	**1.0**	**1.2**	**34.2**

TEN YEAR PRODUCTION BY AREA (continued)
FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2013

		Gas Production Forecast (MMcf)(1)											
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Remainder	Total
Alberta													
	Carson Creek	14.0	12.2	10.7	9.3	8.1	7.1	2.0	0.1	-	-	-	63.4
	Hector	2.6	2.4	2.2	2.0	1.8	1.7	1.5	1.4	1.3	1.2	0.5	18.6
	Judy Creek	0.5	0.3	-	-	-	-	-	-	-	-	-	0.7
	Retlaw	16.2	14.8	13.5	12.3	11.3	10.3	9.4	8.6	7.9	7.2	9.1	120.7
Total		**49.4**	**43.4**	**38.9**	**35.1**	**31.7**	**28.7**	**21.9**	**18.3**	**16.8**	**12.9**	**35.0**	**332.1**

		NGL Production Forecast (Mbbl)(1)											
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Remainder	Total
Alberta													
	Hector	2.6	2.4	2.2	2.0	1.8	1.7	1.5	1.4	1.3	1.2	0.5	18.6
	Judy Creek	1.0	0.9	0.8	0.7	0.7	0.6	0.6	0.5	0.5	0.3	1.6	8.3
	Retlaw	0.4	0.4	0.3	0.3	0.3	0.0	0.2	0.2	0.2	0.2	0.2	2.9
Total		**1.5**	**1.3**	**1.2**	**1.1**	**1.0**	**0.9**	**0.8**	**0.7**	**0.7**	**0.5**	**1.9**	**11.5**

(1) Company working interest production before royalty deductions plus royalty interest share of production.

The following table represents the Company's wells that no reserves were assigned to as at December 31, 2013:

NUMBER OF WELLS WITH NO RESERVES ASSIGNED
AS AT DECEMBER 31, 2013

Province	Area	Number of Wells With No Reserves Assigned
Alberta	Brazeau	1
	Carson Creek	4
	Olds	3
	Ronalane	1
	Viking Kensella	9
	Westerose	2
	Miscellaneous	28
Saskatchewan	Brock	5
	Dankin	1

Operating Costs

The following table is a summary of operating costs as of December 31, 2013:

WORKING INTEREST - OPERATING COSTS
YEAR ENDED DECEMBER 31, 2013

PROVINCE	AREA	Fixed Well-Month	Variable	Gas	Water
		($)	($/bbl)	($/Mcf)	$/bbl)
Alberta	Carson Creek	8,700.00		0.20	2.00
	Coutts	10,000.00	8.00		
	Farrow	2,400.00	8.25		
	Hector	950.00		0.30	
	Judy Creek	1,500.00		0.20	2.00
	Kaybob	2,000.00-6,000.00		1.30	
	Retlaw	7,900.00		0.80	
	Ronalane	1,500.00-8,000.00	2.00		
	Westerose	3,150.00		0.75	
Saskatchewan	Plato	1,800.00	7.50		
Ontario	Gosfield	1,300.00	3.50		

Properties with no Attributed Reserves

The Company does not have any undeveloped lands.

Expiring Lands

The Company has expiring lands totalling 64 gross (51.2) net hectares that will expire in 2014.

Forward Contracts

The Company is not affected by forward sales contract with respect to its oil, natural gas or natural gas liquids production

Tax Horizon

As at December 31, 2013 the Company has the following exploration and development expenditures and undepreciated capital costs which may be carried forward indefinitely to reduce future Canadian taxable income.

Non-capital losses (carry-forward)	$ 6,871,000
UCC	469,000
COPGE	532,000
CDE	57,000
CEE	891,000
Share issue costs	227,000

Exploration and Development Activities

For the year ended December 31, 2013 the Company completed the following exploratory and development wells:

EXPLORATION AND DEVELOPMENT ACTIVITY
FOR THE PERIOD DECEMBER 01, 2012 TO DECEMBER 31, 2013

	Exploratory wells		Development wells	
	Gross	Net	Gross	Net
Oil	**Nil**	**Nil**	**Nil**	**Nil**
Gas	**Nil**	**Nil**	**Nil**	**Nil**
Service	**Nil**	**Nil**	**Nil**	**Nil**
Dry	**Nil**	**Nil**	**Nil**	**Nil**
Total	**Nil**	**Nil**	**Nil**	**Nil**

The Company did not participate in any exploration or development activities during the year ended December 31, 2013.

Petroleum and Natural Gas Interest – Summary of Costs Incurred

		ALL AREAS CANADA
Acquisition Costs		
	Mineral leases	(388)
Exploration Costs		-
	Geological fees	-
	Engineering and consulting	-
	Drilling costs	1,172
	Completion costs	137,863
	Depletion	(247,120)
	Field work, equipment rentals	-
	Costs recovery	-
	Prior adjustments and write-downs	(736,000)
	Royalties received	-

Revenues	(1,062,417)
Total Summary of Costs and Revenue for the period ended December 31, 2013	(1,906,890)

Production History

The following tables set forth the average daily production volumes, royalties, production costs and the resulting netbacks for the periods indicated as at December 31, 2013:

OPERATING NETBACKS

			2013			
			Q4	**Q3**	**Q2**	**Q1**
Oil and NGL		**bbl per day**	**25**	**30**	**41**	**37**
Natural Gas		**Mcf per day**	**143**	**141**	**224**	**159**
boes		**per day**	**49**	**54**	**78**	**63**
Petroleum and natural gas		**$ per boe**	**48.37**	**57.60**	**35.47**	**56.67**
Less	**Royalties**	**$ per boe**	**8.11**	**8.53**	**5.86**	**7.90**
	Operating	**$ per boe**	**29.62**	**39.84**	**26.23**	**32.99**
Operating netback		**$ per boe**	**10.64**	**9.23**	**3.38**	**15.78**

			2012			
			Q4	**Q3**	**Q2**	**Q1**
Oil and NGL		bbl per day	31	37	47	51
Natural Gas		Mcf per day	208	175	238	260
boes		per day	65	66	87	94
Petroleum and natural gas		$ per boe	50.47	45.83	44.36	49.55
Less	Royalties	$ per boe	8.17	3.66	3.76	9.11
	Operating	$ per boe	40.18	47.60	44.58	35.79
Operating netback		**$ per boe**	**2.12**	**(5.43)**	**(6.95)**	**4.65**