Petro Viking Energy Inc.

Statement of Reserves Data and Other Oil and Gas Information

December 31, 2012

Introduction

This Statement of Reserves Data and Other Oil and Gas Information is designed to provide the disclosures prescribed in National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). This document was prepared by the management of Petro Viking Energy Inc. (the "Company") with an effective date of December 31, 2012 with information available up to April 30, 2013. Certain of the information contained herein has been derived from a report entitled "Evaluation of the P&NG Reserves of Petro Viking Energy Inc. (as of December 31, 2012)" (the "McDaniel Report") as prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") dated April 17, 2013. McDaniel is a Qualified Reserves Evaluator as defined pursuant to NI 51-101.

Reserves Definitions

The crude oil, natural gas and natural gas products reserves estimates presented in the McDaniel Report have been based on the definitions and guidelines prepared by the Standing Committee on Reserves Definitions of the CIM (Petroleum Society) as presented in the Canadian Oil and Gas Evaluators Handbook ("COGE Handbook"). A summary of those definitions is presented below.

Reserves Categories

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, and shall be disclosed.

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

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.

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.

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.

Development and Production Status

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

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.

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.

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.

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, 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 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 reserves 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 estimates 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 actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- At least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative 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.

Net Present Value Estimates

The net present values of the crude oil, natural gas and natural gas products reserves were obtained by employing future production and revenue analyses. The future crude oil production was generally predicated on the anticipated performance characteristics of the individual wells and reservoirs in question. The future natural gas production was also predicated on the anticipated performance characteristics of the individual wells and reservoirs in question with an allowance for any gas sales contract or gas processing facility restrictions. In those areas where shut-in natural gas reserves exist, the commencement of production was based on the proximity to a pipeline connection and the relevant factors relating to the future marketing of the reserves. The future production of gas-cap reserves was assumed to occur near the end of the oil producing life. Solution gas production was based on the forecast of the oil producing rates and current and forecast sales gas-oil ratios. The natural gas products production forecasts were based on the anticipated recoveries of these products from the produced natural gas.

The Company's share of future crude oil revenue was derived by employing the Company's share of production and the indicated reference crude oil price less the historical quality and transportation price differential for each respective field. The indicated natural gas prices with an adjustment for the heating value of the gas were employed to calculate the Company's share of future natural gas revenues. The indicated reference natural gas products prices with adjustments to reflect historical price differentials realized by the Company in each respective property were employed to calculate the Company's share of future natural gas products revenues. Royalties and mineral taxes payable to the Crown were estimated based on the methods in effect as of December 31, 2012. Freehold and overriding royalties payable to others were estimated based on the indicated applicable rates. In those cases where a proportionate share of the natural gas gathering and processing charges were indicated to be payable by the Crown or royalties owned by others, these charges have been deducted in determining the net royalties payable.

In all cases, estimates of the applicable capital expenditures and operating costs were deducted in arriving at the Company's share of future net revenues. An allowance for future well abandonment costs was made for all of the Company's existing working interest wells, however, no allowance was made for the reclamation of well sites or the abandonment and reclamation of any facilities. To the extent that undeveloped reserves are assigned to undrilled locations, then both abandonment and reclamation costs are factored into the forecast future net revenues associated with those locations. The net present values were then obtained by employing 5, 10, 15 and 20 percent nominal annual discount rates compounded annually.

Presentation of Reserve Information

"Gross" reserves are the company working interest share before deduction of royalties. "Net" reserves are the company working interest share after deduction of royalties.

General and administrative expenses and overhead recoveries are not deducted in the determination of future net revenues.

Use of Barrels of Oil Equivalent (boe)

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

Significant Risk Factors and Uncertainties

Estimating reserves is forecasting the future and is inherently uncertain. The reserve and recovery information contained in the McDaniel Report are only estimates and the actual production and reserves may be different than the estimates prepared by McDaniel. When estimating reserves, McDaniel considers a number of factors and makes assumptions including, among others:

- Historical production compared with production rates from similar properties;
- Assumptions regarding initial production and subsequent decline rates;
- Ultimate recovery of reserves;
- Assumptions about future commodity prices, development and operating costs;
- The effect of governmental regulation, royalty and tax regimes;
- Timing and amount of capital expenditures; and
- Forecasts of results of future development activity.

These factors and assumptions were based on information at the date the evaluation was prepared. Many of these factors are subject to change and are beyond the Company's control. If these factors and assumptions prove to be inaccurate, the actual results may vary materially from the reserve and cash flow estimates. Results may be less than those contained in the evaluation to the extent that forecast development activities do not achieve the level of success assumed in the evaluation.

Caution to Reader

The following tables set forth certain information relating to the oil and natural gas reserves of the Company and the present value of the estimated future net revenue associated with such reserves, and is derived from the McDaniel report. It should not be assumed that the estimated present worth values of net production revenue contained in the following tables represents the fair market value of the reserves. There is no assurance that the price and cost assumptions contained in the constant price and cost and escalating price and cost assumption cases will be attained and variances could be material.

Abbreviations

bbl	barrel of oil or NGL;
bcf	billion cubic feet of natural gas;
bpd	barrel of oil or NGL per day;
boe	barrel of oil equivalent determined by converting a volume of natural gas to barrels using the ratio of 6 Mcf to one barrel;
boe/d	barrel of oil equivalent per day;
Company	Petro Viking Energy Inc.;
Mbbl	thousand barrels;
Mboe	thousand barrels of oil equivalent;
Mcf	thousand cubic feet of natural gas;
Mcfe	Mcf of gas equivalent determined by converting a volume of oil or NGL to Mcf using the ratio of 0.1667 barrels to 1 Mcf;
Mcf/d	thousand cubic feet of natural gas per day;
MMcf	million cubic feet of natural gas;
MMcf/d	million cubic feet of natural gas per day;
NGLs	natural gas liquids;
$US	United States dollar;
$Cdn	Canadian dollar.

Conversion

In this document 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
bbls	cubic metres	0.159
cubic metres	bbls	6.29
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

Part 1 Date of Statement

1.1 Relevant Dates

1. Date of Statement: April 17, 2013
2. Effective Date of Statement: December 31, 2012
3. Preparation Date of Statement: April 17, 2013

Part 2 Disclosure of Reserves Data

2.1 Reserves Data (Forecast Prices and Costs)

a) Breakdown of Proved plus Probable Reserves (Forecast Prices)

Reserve Category	Light and Medium Oil		Heavy Oil		Natural Gas (non-associated & associated)		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)
Proved								
Developed Producing	35.00	32.20	3.00	2.70	422.50	382.40	12.10	8.40
Developed Non- producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	35.00	32.20	3.00	2.70	422.50	382.40	12.10	8.40
Probable	10.80	9.70	1.10	1.00	138.40	125.00	4.40	3.10
Total Proved plus Probable	45.80	41.90	4.00	3.60	560.90	507.40	16.50	11.50

b) Net Present Value of Future Net Revenue (Forecast Prices) ***Before*** *Tax*

Company Share of Net Present Value Before Income Tax (M$)	@ 0.0%	@ 5.0%	@ 10.0%	@ 15.0%	@ 20.0%	Future Net Value 10%/Yr ($/boe)
Proved						
Developed Producing	1,794.40	1,568.40	1,395.90	1,261.30	1,153.60	11.57
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-
Total Proved	1,794.40	1,568.40	1,395.90	1,261.30	1,153.60	11.57
Probable	778.00	524.80	382.70	294.70	236.20	9.71
Total Proved Plus Probable	2,572.40	2,093.20	1,778.60	1,556.00	1,389.80	11.11

Unit Values are based on net reserve volumes.

Notes: NPV of FNR include all resource income: sale of oil, gas, by-product reserves, processing third party reserves, other income.

*c) Net Present Value of Future Net Revenue (Forecast Prices) **After** Tax*

Company Share of Net Present Value After Income Tax (M$)	**@ 0.0%**	**@ 5.0%**	**@ 10.0%**	**@ 15.0%**	**@ 20.0%**
Proved					
Developed Producing	1,794.40	1,568.40	1,395.90	1,261.30	1,153.60
Developed Non-Producing	-	-	-	-	-
Undeveloped	-	-	-	-	-
Total Proved	1,794.40	1,568.40	1,395.90	1,261.30	1,153.60
Probable	778.00	524.80	382.70	294.70	236.20
Total Proved Plus Probable	2,572.40	2,093.20	1,778.60	1,556.00	1,389.80

Unit Values are based on net reserve volumes.
Notes: NPV of FNR include all resource income: sale of oil, gas, by-product reserves, processing third party reserves, other income.
Income taxes: includes all resource income; apply appropriate income tax calculations; include prior tax pools

d) Additional Information Concerning Future Net Revenue (Forecast Price)

Undiscounted Revenue and Costs	**Sales Revenue(1) M$**	**Royalties(2) M$**	**Operating Costs M$**	**Total Development Costs M$**	**Well Abandonment Costs M$**	**Future Net Revenue Before Tax M$**	**Income Taxes M$**	**Future Net Revenue After Tax M$**
Total Proved Reserves	**6,066**	**676**	**3,217**	**-**	**379**	**1,794**		**1,794**
Total Proved & Probable Reserves	**8,402**	**973**	**4,448**	**-**	**408**	**2,572**		**2,572**

(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.

Discounted Future Net Revenue by Production Group	**@ 0.0%**	**@ 10.0%**	**@ 15.0%**	**Unit Values (2)**		**BOEs (3)**
NPV of FNR Before Income Taxes (4)	**M$**	**M$**	**M$**	**$/bbl**	**$/Mcf**	**(Value Conversion)**
Light and Medium Oil (Including Associated Gas and Byproducts)						
Proved Developed Producing	995.00	866.00	808.00		26.88	-
Proved Non-Producing	-	-	-		-	-
Proved Undeveloped	-	-	-		-	-
Total Proved	995.00	866.00	808.00		26.88	-
Total Probable	387.00	235.00	191.00		24.13	-
Total Proved & Probable	1,382.00	1,101.00	999.00		26.24	-

Discounted Future Net Revenue by Production Group	@ 0.0%	@ 10.0%	@ 15.0%	Unit Values [2]	BOEs [3]
NPV of FNR Before Income Taxes [4]	M$	M$	M$	$/bbl $/Mcf	(Value Conversion)
Heavy Oil					
Proved Developed Producing	(56.00)	(28.00)	(19.00)	(10.68)	(2.52)
Proved Non-Producing	-	-	-	-	-
Proved Undeveloped	-	-	-	-	-
Total Proved	(56.00)	(28.00)	(19.00)	(10.68)	(2.52)
Total Probable	(11.00)	(4.00)	(2.00)	(4.21)	(5.73)
Total Proved & Probable	(67.00)	(32.00)	(21.00)	(8.97)	(2.93)
Non-Associated Gas (Including Byproducts)					
Proved Developed Producing	856.00	559.00	473.00	1.46	18.37
Proved Non-Producing	-	-	-	-	-
Proved Undeveloped	-	-	-	-	-
Total Proved	856.00	559.00	473.00	1.46	18.37
Total Probable	402.00	152.00	106.00	1.22	19.84
Total Proved & Probable	1,258.00	710.00	579.00	1.40	18.71

(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.
(4) Processing income is included where applicable.

Part 3 Pricing Assumption

3.1 Constant Prices Used in Estimates (N/A)

3.2 Forecast Prices Used in Estimates

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	Alberta Heavy Crude Oil $C/bbl	Sask Cromer Medium Crude Oil $C/bbl	Edmonton Cond. & Natural Gasolines $/bbl	Edmonton Propane $/bbl	Edmonton Butanes $/bbl	Edmonton NGL Mix $/bbl	Inflation %	US/CAN Exchange Rate $US/$CAN
	(1)	(2)	(3)	(4)	(5)	(6)				(7)		
Forecast												
2013	92.50	107.50	87.50	75.30	65.60	83.10	97.50	34.90	64.10	57.60	2.0	1.000
2014	92.50	102.50	90.50	77.80	67.90	86.00	95.60	44.20	69.60	63.40	2.0	1.000
2015	93.60	101.40	92.60	79.60	69.50	88.00	95.70	52.00	74.60	68.70	2.0	1.000
2016	95.50	100.80	94.50	81.30	70.90	89.80	97.70	53.70	76.20	70.40	2.0	1.000
2017	97.40	100.10	96.40	82.90	72.30	91.60	99.60	55.60	77.70	72.10	2.0	1.000
2018	99.40	102.20	98.30	84.50	73.70	93.40	101.60	57.30	79.20	73.80	2.0	1.000
2019	101.40	104.20	100.30	86.30	75.20	95.30	103.70	58.40	80.80	75.30	2.0	1.000
2020	103.40	106.30	102.30	88.00	76.70	97.20	105.70	59.60	82.40	76.80	2.0	1.000
2021	105.40	108.30	104.30	89.70	78.20	99.10	107.80	60.80	84.00	78.30	2.0	1.000
2022	107.60	110.60	106.50	91.60	79.90	101.20	110.10	62.00	85.80	80.00	2.0	1.000
2023	109.70	112.70	108.50	93.30	81.40	103.10	112.20	63.20	87.40	81.50	2.0	1.000
2024	111.90	115.00	110.70	95.20	83.00	105.20	114.40	64.50	89.20	83.10	2.0	1.000
2025	114.10	117.30	112.90	97.10	84.70	107.30	116.70	65.80	91.00	84.80	2.0	1.000
2026	116.40	119.60	115.20	99.10	86.40	109.40	119.10	67.10	92.80	86.50	2.0	1.000
2027	118.80	122.10	117.50	101.10	88.10	111.60	121.50	68.50	94.70	88.30	2.0	1.000
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	1.000

(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) Heavy crude oil 12 degrees API at Hardisty Alberta (after deduction of blending costs to reach pipeline quality)
(6) Midale Cromer crude oil 29 degrees API, 2.0% sulphur
(7) NGL Mix based on 45 percent propane, 35 percent butane and 20 percent natural gasolines.

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)					
Forecast								
2013	3.75	3.35	3.15	3.15	3.15	3.25	3.25	3.05
2014	4.30	3.85	3.65	3.65	3.65	3.75	3.75	3.55
2015	4.85	4.35	4.15	4.15	4.15	4.25	4.25	4.05
2016	5.25	4.70	4.50	4.50	4.50	4.60	4.60	4.40
2017	5.70	5.10	4.90	4.90	4.90	5.00	5.00	4.80
2018	6.10	5.45	5.25	5.25	5.25	5.35	5.35	5.15
2019	6.20	5.55	5.30	5.30	5.30	5.40	5.40	5.20
2020	6.35	5.70	5.45	5.45	5.45	5.55	5.55	5.35
2021	6.45	5.80	5.55	5.55	5.55	5.65	5.65	5.45
2022	6.60	5.90	5.65	5.65	5.65	5.75	5.75	5.55
2023	6.70	6.00	5.75	5.75	5.75	5.85	5.85	5.65
2024	6.85	6.15	5.90	5.90	5.90	6.00	6.00	5.80
2025	7.00	6.25	6.00	6.00	6.00	6.15	6.15	5.85
2026	7.10	6.35	6.10	6.10	6.10	6.25	6.25	5.95
2027	7.25	6.50	6.25	6.25	6.25	6.40	6.40	6.10
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

Reconciliation of Company Gross [1] Reserves (Before Royalty) by Principal Product Type as of December 31, 2012												
	Light and Medium Oil			Heavy Oil			Associated, Non-Associated and Solution Gas			Natural Gas Liquids		
Factors	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2011	46.2	13.3	59.5	7.4	2.2	9.5	547.4	167.1	714.5	14.1	4.5	18.6
Extensions												
Improved Recovery												
Technical Revisions	0.6	-2.5	-1.9	-2.9	-1.1	-4.0	-32.1	-28.7	-60.8	-0.5	-0.1	-0.6
Discoveries												
Acquisitions												
Dispositions												
Economic Factors												
Production	-11.8		-11.8	-1.5		-1.5	-92.8		-92.8	-1.5		-1.5
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

(1) Gross Reserves means the Company's working interest reserves before calculation of royalties, and before consideration of the Company's royalty interests.

Part 5 Additional Information Relating to Reserves

5.1 Undeveloped Reserves

The Company did not have any undeveloped reserves (for both proved and probable) in the three most recent financial years

5.2 Significant Factors or Uncertainties

Reserves can be significantly affected by changes in product pricing, operating costs, royalty rates and well performance. The Company's wells are subject to normal decline and unpredictable changes in operating environment in facilities operated by third parties.

5.3 Future Development Costs

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

Part 6 Other Oil and Gas Information

6.1 Oil & Gas Properties and Wells

a) *1. All of the Company's reserves, properties and assets are located in Alberta and Saskatchewan, Canada.*

b) *2. The following table summarizes Petro Viking's interest, as at December 31, 2012, in wells that are producing or which Petro Viking considers to be capable of production:*

Producing Oil		**Non-Producing Oil**		**Producing Natural Gas**		**Non-Producing Natural Gas**	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
41.00	19.28	11.00	6.35	24.00	4.32	22.00	6.49

6.2 Properties with No Attributed Reserves

The following table presents the undeveloped land holdings of the Company at December 31, 2012. All lands are located in Alberta and Saskatchewan, Canada.

Gross Hectares:	**Net Hectares:**
8,112	3,544

Of these lands, 1,561 gross (1,561 net) hectares will expire in 2013.

6.3 Forward Contracts

The Company is not affected by forward sale contracts with respect to its oil, natural gas or natural gas liquids production.

6.4 Additional Information Concerning Abandonment and Reclamation Costs

a) The Company estimates abandonment and reclamation costs on a well by well and facility by facility basis, including both the cost to retrieve salvageable equipment and reclaim the property.

b) The Company has 41.33 net wells on which it expects to incur abandonment and reclamation costs.

c) The Company has estimated its well, facilities and pipeline abandonment and reclamation costs to be $3,778,928. The present value of such costs, discounted at 10% is estimated to be $2,710,815.

d) The estimate of the costs to abandon and reclaim wells (for which reserves were not assigned), and certain facilities and pipelines that have not been included in the estimate of future net revenue disclosed in Part 2 is $ Nil.

e) The Company estimates that it will spend $Nil in the next three years on abandonment and reclamation work.

6.5 Tax Horizon

The Company was not required to pay income taxes with respect to the taxation year ended December 31, 2012. Based on the future net revenue disclosed in Part 2 and the existing tax pools and non-capital losses available from previous years, the Company does not anticipate being taxable for at least the next five years.

6.6 Costs Incurred in 2012

a) Property acquisition costs $Nil

b) Exploration costs $ 93,750

c) Development costs $129,077

d) Property dispositions $ 83,000

6.7 Exploration and Development Activities

The Company did not participate in the drilling of any exploratory wells (0 net) or development wells (0 net) during the year.

6.8 Production Estimates

a) *The volume of production (Company Gross) estimated for 2013 reflected in the estimation of future net revenue disclosed under Part 2 is:*

Reserve Category	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids
	(Mbbl)	(Mbbl)	(MMcf)	(Mbbl)
Proved	10.90	-	59.50	1.50
Probable	0.20	-	0.70	-
Proved plus Probable	11.10	-	60.20	1.60

b) *The Carson Creek and Kaybob Areas are forecast to account for 28% of the estimated 2013 production (based on the Total Proved production forecasts for the year- Company Gross). The Ronalane Area is forecast to account for 25% of the estimated 2013 production (based on the Total Proved production forecasts for the year – Company Gross).*

Property Name	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids
	(Mbbl)	(Mbbl)	(MMcf)	(Mbbl)
Carson Creek, Kaybob, Alberta	-	-	31.3	0.8
Ronolane, Alberta	5.4	-	-	-

6.9 Production History for 2012

The following table sets forth average daily production volume, product prices, royalties, operating costs, and netbacks for each quarter of 2012.

		Q1	Q2	Q3	Q4
Daily Production volumes	boe/d	95	87	66	65
Price received	$/boe	49.55	44.36	45.43	50.47
Royalty	$/boe	9.11	6.73	3.66	8.17
Operating cost	$/boe	35.79	44.58	47.60	40.18
Netback	$/boe	4.64	(6.95)	(5.83)	2.12

Calculations subject to rounding differences.

Appendices:

McDaniel & Associates Consultants Ltd.

April 17, 2013

Petro Viking Energy Inc.
200, 744 – 4th Avenue SW
Calgary, Alberta
T2P 3T4

Attention: The Board of Directors of Petro Viking Energy Inc.

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator of Petro Viking Energy Inc. (the "Company")

To the Board of Directors of Petro Viking Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012 estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated 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 by us, for the year ended December 31, 2012, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

		Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Preparation Date of Evaluation Report	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
April 17, 2013	Canada	-	1,779	-	1,779

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the preparation date.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by P. A. Welch"

P. A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta
April 17, 2013

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Terms to which a meaning is ascribed in National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities have the same meaning herein.

Management of Petro Viking Energy Inc. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated and reviewed the Company's reserves data. The report of the independent qualified reserves evaluator and auditor will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the Board of Directors of the Company has:

1. reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;
2. met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and
3. reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the Board of Directors has reviewed the Company'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 approved:

1. the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
2. the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and
3. the content and filing of this report.

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

Armstrong, British Columbia, Canada, April 17, 2013

(Signed)

Irvin Eisler
Chief Executive Officer and Director

(Signed)

Keith Watts
Director

(Signed)

Andre Voskiul
Director

(Signed)

Lars Glimhagen
Director