Petro Viking Energy Inc.

STATEMENT OF RESERVES DATA

AND OTHER OIL AND GAS INFORMATION

FORM 51-101F1

Effective December 31, 2011

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Petro Viking Energy Inc.
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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, 2011 with information available up to March 31, 2012. 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, 2011)" (the "McDaniel Report") as prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") dated April 16, 2012. 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, 2011. 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

Certain terms and abbreviations used in this document are defined below:

"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	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

Part 1 Date of Statement

1.1 Relevant Dates

1. Date of Statement: April 16, 2012
2. Effective Date of Statement: December 31, 2011
3. Preparation Date of Statement: March 7, 2012

Part 2 Disclosure of Reserves Data

2.1 Reserves Data (Forecast Prices and Costs)

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

Table 1
NI 51-101
Summary of Oil and Gas Reserves as of December 31, 2011
Forecast Prices and Costs

	Reserves									
Reserve Category	**Light and Medium Oil**		**Heavy Oil**		**Coal Bed Methane**		**Natural Gas (non-associated & associated)**		**Natural Gas Liquids**	
	Gross (Mbbl)	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcfl)**	**Net (MMcfl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved										
Developed Producing	46.2	41.0	7.4	6.8	0	0	547.4	493.0	14.1	8.5
Developed Non-producing	0	0	0.0	0.0	0	0	0	0	0	0
Undeveloped	0	0	0.0	0.0	0	0	0	0	0	0
Total Proved	**46.2**	**41.0**	**7.4**	**6.8**	**0**	**0**	**547.4**	**493.0**	**14.1**	**8.5**
Probable	13.3	11.7	2.2	2.0	0	0	167.1	150.4	4.5	2.7
Total Proved plus Probable	**59.5**	**52.7**	**9.5**	**8.8**	**0**	**0**	**714.5**	**643.4**	**18.6**	**11.1**

Reference: Item 2.2(1) of Form 51-101F1

b) Net Present Value of Future Net Revenue (Forecast Prices) both Before and After Tax

Table 2
NI 51-101
Summary of Net Present Values of Future Net Revenue as of December 31, 2011
Forecast Prices and Costs

Reserves Category	Net Present Values of Future Net Revenue					
	Before Income Taxes / Discounted at (%/Year)					Future Net Value 10%/Yr ($/boe)
	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	
Proved						
Developed Producing	2.64	2.30	2.05	1.86	1.70	12.89
Developed Non-Producing	0	0	0	0	0	0
Undeveloped	0	0	0	0	0	0
Total Proved	**2.64**	**2.30**	**2.05**	**1.86**	**1.70**	**12.89**
Probable	1.09	0.74	0.54	0.42	0.34	11.37
Total Proved Plus Probable	**3.73**	**3.04**	**2.60**	**2.28**	**2.05**	**12.54**

Table 2
NI 51-101
Summary of Net Present Values of Future Net Revenue as of December 31, 2011
Forecast Prices and Costs

Reserves Category	Net Present Values of Future Net Revenue					
	After Income Taxes / Discounted at (%/Year)					
	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	
Proved						
Developed Producing	2.64	2.30	2.05	1.86	1.70	
Developed Non-Producing	0	0	0	0	0	
Undeveloped	0	0	0	0	0	
Total Proved	**2.64**	**2.30**	**2.05**	**1.86**	**1.70**	
Probable	1.09	0.74	0.54	0.42	0.34	
Total Proved Plus Probable	**3.73**	**3.04**	**2.60**	**2.28**	**2.05**	

Reference Item 2.2(2) of Form 51-101F1
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

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

a) Undiscounted Revenue and Costs

Table 3
NI 51-101
Total Future Net Revenue
Undiscounted
As of December 31, 2011
Forecast Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment / Other Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved	8,809	1,148	4,525	0	492	2,644	0	2,644
Proved Plus Probable	11,889	1,562	6,087	0	508	3,732	0	3,732

Reference Item 2.2(3)(b) of Form 51-101F1

b) Discounted Future Net Revenue by Production Group

Table 4
NI 51-101
Net Present Value of Future Net Revenue by Production Group
As of December 31, 2011
Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Unit Value Before Income Taxes (Discounted at 10%/Year) ($/boe)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	1,063	25.96
	Heavy Oil	78	11.44
	Natural Gas (including associated by-products)*	910	14.04
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	1,318	25.01
	Heavy Oil	119	13.46
	Natural Gas (including associated by-products)*	1,160	13.86

Reference Item 2.2(3)(c) of Form 51-101F1
Unit Values are based on net reserve volumes
* Includes corporate Capital GCA, if applicable

2.2 Supplementary Disclosure (Constant prices and Costs): NA

2.3 Reserves Disclosure Varies With Accounting:

1. a) Consolidated Financial Disclosure:
   i. The disclosure includes working interest and royalty interest reserves from properties owned by the following corporate entities: Petro Viking Energy Inc.
   ii. The minority interest portion of the reserves disclosure is not material.

   b) Proportionate Consolidation: N/A

   c) Equity Accounting: N/A

2.4 Future Net Revenue Disclosure Varies with Accounting:

1. a) Consolidated Financial Disclosure:
   i. The disclosure includes future net revenues from properties owned by the following corporate entities: Petro Viking Energy Inc.
   ii. The minority interest portion of the future net revenue disclosure is not material.

   b) Equity Accounting: N/A

Part 3 Pricing Assumption

3.1 Constant Prices Used in Estimates (N/A)

3.2 Forecast Prices Used in Estimates

Table 5
NI 51-101
Summary of Pricing and Inflation Rate Assumptions
as of December 31, 2011
Forecast Prices and Costs

	Oil							
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40º API ($Cdn/bbl)	Cromer Medium 29.3º API ($Cdn/bbl)	Natural Gas[1] AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes F.O.B. Field Gate ($Cdn/bbl)	Inflation Rate[2] (%/Yr)	Exchange Rate[3] ($US/$Cdn)
Historical								
2007	72.30	76.35	65.40	6.65	77.36	63.75	2.0	0.935
2008	99.60	102.20	93.20	8.15	104.75	75.25	2.4	0.943
2009	61.80	65.90	62.80	4.20	68.15	49.25	2.0	0.880
2010	79.50	77.50	73.80	4.15	84.25	66.05	2.0	0.971
2011	94.80	95.20	88.35	3.70	104.20	75.50	2.0	1.011
Forecast								
2012	97.50	99.00	91.00	3.50	106.00	76.20	2.0	0.975
2013	97.50	99.00	91.00	4.20	104.10	79.80	2.0	0.975
2014	100.00	101.50	93.30	4. 70	104.60	81.80	2.0	0.975
2015	100.80	102.30	94.10	5.10	105.50	82.40	2.0	0.975
2016	101.70	103.20	94.90	5.55	106.40	83.20	2.0	0.975
2017	102.70	104.20	95.80	5.90	107.50	84.00	2.0	0.975
2018	103.60	105.10	96.60	6.25	108.50	84.70	2.0	0.975
2019	104.50	106.00	97.50	6.45	109.40	85.40	2.0	0.975
2020	105.40	106.90	98.30	6.70	110.40	86.10	2.0	0.975
2021	107.60	109.20	100.30	6.85	112.80	88.00	2.0	0.975
Thereafter				Escalation Rate of 2.0%				

(1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table

Notes: Product sales prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

Reference Item 3.2 of Form 51-101F1

The Company's weighted average historical prices for 2011 are as follows:

Oil & NGL	$79.99/bbl
Natural Gas	$3.40/mcf

Part 4 Reconciliation of changes in Reserves and Future NetRevenue

Table 6
NI 51-101
Reconciliation of Company Gross (1) Reserves (Before Royalty)
by Principal Product Type
as of December 31, 2011
Forecast Prices and Costs

	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, 2010	**24.2**	**7.7**	**32.1**	**0**	**0**	**0**	**372.1**	**123.5**	**495.6**	**19.8**	**5.9**	**25.7**
Extensions												
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	8.6	0	8.6	0	0	0	33.5	-10.7	22.8	-5.6	-1.6	-6.8
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	20.7	5.6	26.3	8.6	2.2	10.8	229.0	54.4	283.1	1.1	0.4	1.5-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production *	-7.6	-	-7.6	-1.3	-	-1.3	-87.2	-	-87.2	-1.8	-	-1.8
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

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

* Production as reported by Company

Reference: Item 4.1 of Form 51-101F1

Part 5 Additional Information Relating to Reserves

5.1 Undeveloped Reserves

The following tables set out the volumes of proved and probable undeveloped reserves and the year that they were first attributed for the three most recent financial years:

Table 7
NI 51-101
Undeveloped Reserves Vintage by Principal Product Type
as of December 31, 2011
Forecast Prices and Costs

	Light and Medium Oil and		Heavy Oil		Natural Gas		Natural Gas Liquids	
	First Attributed Gross Proved (Mbbl)	Booked Gross (Mbbl)	First Attributed Gross Proved (Mbbl)	Booked Gross (Mbbl)	First Attributed Gross Proved (MMcf)	Booked Gross (MMcf)	First Attributed Gross Proved (Mbbl)	Booked Gross (Mbbl)
Proved Undeveloped								
Prior to December 31, 2008	-	-	-	-	-	-	-	-
December 31, 2009	-	-	-	-	-	-	-	-
December 31, 2010	-	-	-	-	-	-	-	-
December 31, 2011	-	-	-	-	-	-	-	-
Probable Undeveloped								
Prior to December 31, 2008	-	-	-	-	-	-	-	-
December 31, 2009	-	-	-	-	-	-	-	-
December 31, 2010	-	-	-	-	-	-	-	-
December 31, 2011	-	-	-	-	-	-	-	-

Undeveloped reserves are expected to be recovered from known accumulations where sufficient capital will be spent that would render the reserves capable of production and where they fully meet the requirements of the reserve classification to which they are assigned.

All proved undeveloped and probableoil reserves are expected to be developed before December 31, 2013. Proved undeveloped and probable gas reserves will be developed when natural gas prices improve to levels that provide for positive operating cash flow.

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

1. (a)
   i. Proved Reserves –there are no future development costs;
   ii. Proved plus Probable Reserves – there are no future development costs.

   (b)
   i. The undiscounted future development costs of $Nilon proved reserves and $Nilon proved plus probable reserves will be incurred in Canada;
   ii. The future development costs incurred over the next five years are as follows:

Year Costs Estimated to be Incurred	Costs Attributed to Proved Reserves (M$)	Costs Attributed to Proved plus Probable Reserves (M$)
2012	-	-
2013	-	-
2014	-	-
2015	-	-
2016	-	-

2. Management expectations are that future development costs will be funded using internally-generated cash flow and bank operating lines. To the extent that commodity prices soften, development costs may be deferred.

Part 6 Other Oil and Gas Information

6.1 Oil & Gas Properties and Wells

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

2. The following table summarizes Petro Viking's interest, as at December 31, 2011, 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	19.28	11	6.35	24	4.32	22	6.49

6.2 Properties With No Attributed Reserves

The following table presents the undeveloped land holdings of the Company at December 31, 2011. All lands are located in Alberta and Saskatchewan, Canada.

Gross Hectares	Net Hectares
8,311	3,717

Of these lands, 199 gross (173 net) hectares will expire in 2012.

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 has41.33 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 $3,798,277. The present value of such costs, discounted at 10%, is estimated to be $2,611,550.

(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 $400,000 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, 2011. 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 2011

a) Property acquisition costs	$5,300,782
b) Exploration costs	$ Nil
c) Development costs	$1,825,868
d) Property dispositions	$ 125,000

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

1. The volume of production (Company Gross) estimated for 2012 reflected in the estimation of future net revenue disclosed under Part 2 is:

Reserve Category	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Proved	14.2	0	92.9	1.8
Probable	0.3	0	1.4	0
Proved plus Probable	**14.5**	**0**	**94.3**	**1.8**

2. The RonalaneAreais forecast to accountfor 46% of the estimated 2012 production (based on the Total Proved production forecastsfor the year – Company Gross). The Carson Creek and Kaybob Areas is forecast to account for 50% of the estimated 2012 production (based on the Total Proved production forecasts for the year- Company Gross).

Property Name	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Ronalane, Alberta	6.5	0	0	0
Carson Creek,Kaybob Alberta	0	0	46.1	1.1

6.9 Production History for 2011

The following table sets forth average daily production volume, product prices, royalties, operating costs, and netbacks for each quarter of 2011.

		Q1	Q2	Q3	Q4
Daily Production volumes	boe/d	32	33	81	104
Price received	$/boe	39.99	40.26	50.79	47.90
Royalty	$/boe	7.14	7.76	10.25	7.11
Operating cost	$/boe	36.91	30.21	29.82	33.91
Netback	$/boe	-4.05	2.29	10.71	6.88
Calculations subject to rounding differences.					