National Instrument 51-101 Form F1

Galileo Petroleum Ltd.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Effective June 30, 2013

ABBREVIATIONS AND CONVERSIONS

In this document the abbreviations set forth below have the following meanings:

Oil, Natural Gas Liquids and Natural Gas

Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
MBbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMBbls	million barrels	MMcf/d	million cubic feet per day
Bbls/d	barrels per day	MMBTU	million British Thermal Units
BOPD	barrels of oil per day	Bcf	billion cubic feet
STB	standard tank barrels	GJ	gigajoule
NGLs	natural gas liquids		

Other

AECO	EnCana Corp’s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
^{o}API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28^{o} API or higher is generally referred to as light crude oil.
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/d	barrel of oil equivalent per day
m^3	cubic meters
MBOE	1,000 barrels of oil equivalent
$000 or M$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.

RESERVES DATA AND FUTURE NET REVENUE

PART 1 DATE OF STATEMENT

In accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities, Fekete Associates Inc. ("Fekete") prepared an independent engineering evaluation, as at June 30, 2013 of Galileo Petroleum Ltd. (the "Corporation") oil and gas interests. The date of preparation of the "Fekete Report" was October 28th, 2013. The tables below are a summary of oil and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the Fekete Report based on forecast price and cost assumptions. The tables summarize the data contained in the Fekete Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly. **The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by Fekete. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by Fekete represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Corporation's oil and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein. There is no assurance that the price and cost assumptions will be attained and variances could be material.**

The Fekete Report is based on certain factual data supplied by the Corporation and Fekete's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Corporation's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by Galileo Petroleum Ltd. to Fekete and accepted without any further investigation. Fekete accepted this data as presented and neither title searches nor field inspections were conducted.

PART 2 DISCLOSURE OF RESERVES DATA

Item 2.1 Reserves Data (Forecast Prices and Costs)

Summary of Oil and Gas Reserves

	Gross Reserves			Net Reserves		
	Light, Medium & Heavy Crude Oil	Natural Gas	Natural Gas Liquids	Light, Medium & Heavy Crude Oil	Natural Gas	Natural Gas Liquids
	(MBbls)	(MMCF)	(MBbls)	(MBbls)	(MMCF)	(MBbls)
Proved						
Developed Producing	3.0	-	-	3.0	-	-
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	9.0	115	1.7	9.0	92	1.7
Total Proved	12.0	115	1.7	12.0	92	1.7
Probable	2.3	19	0.3	2.0	8.0	0.3
Total Proved plus Probable	14.3	134	2.0	14.0	100	2.0

Net Present Value of Future Net Revenue of Oil and Gas Reserves

	Before Future Income Tax Expenses and Discounted at				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved					
Developed Producing	54.5	52.9	51.2	49.6	48.0
Developed Non-Producing	-	-	-	-	-
Undeveloped	368.9	301.4	249.1	207.8	174.7
Total Proved	423.4	354.3	300.3	257.4	222.7
Probable	130.1	126.3	120.1	112.8	105.4
Total Proved plus Probable	553.5	480.6	420.4	370.2	328.1

Future Net Revenue by Production Group (Net Present Value and Net Unit Value Basis)

	Before Future Income Tax Expenses and Discounted at 10%			
	Heavy, Oil(1)	Natural Gas(2)	Heavy Oil(3)	Natural Gas(4)
	(M$)	(M$)	($/Bbl)	($/Mcf)
Proved				
Developed Producing	51.2	-	17.1	-
Developed Non-Producing	-	-	-	-
Undeveloped	54.0	195.1	6.0	2.1
Total Proved	105.2	195.1	8.7	2.1
Probable	66.1	53.9	33.0	6.7
Total Proved plus Probable	171.3	249.0	12.2	2.4

Notes: (1) Including solution gas and other by-products
(2) Including by-products, but excluding solution gas from oil wells
(3) Net present value of oil, solution gas and NGL's ($) divided by total net oil reserves (bbl)
(4) Net present value of natural gas and NGLs ($) divided by total net gas reserves (Mcf)

Additional Information Concerning Future Net Revenue – (Undiscounted)

	Revenue	Royalties	Operating Costs	Develop-ment Costs	Abandon-ment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Total Proved Reserves	1439.9	116.5	482.2	365.9	51.9	423.4	-	423.4
Total Proved plus Probable Reserves	1672.9	163.5	537.7	365.9	52.3	553.5	-	553.5

Item 2.2 Supplemental Disclosure (Constant Prices and Costs)

No supplemental disclosure using Constant Prices and Costs has been made.

Item 2.3 Reserves Disclosure Varies with Accounting

The disclosed reserves data and future net revenues are 100% attributed to the "Corporation".

Item 2.4 Future Net Revenue Disclosure Varies with Accounting

The disclosed reserves data and future net revenues are 100% attributed to the "Corporation".

PART 3 PRICING ASSUMPTIONS

Item 3.1 Constant Prices Used In Estimates

No supplemental disclosure under Item 2.2 has been made.

Item 3.2 Forecast Prices Used In Estimates

Fekete employed the following pricing and exchange rate assumptions as of June 30, 2013, in estimating the Corporation's reserves data using forecast prices and costs.

Oil and Liquids Forecast

FEKETE ASSOCIATES INC.
OIL AND LIQUIDS FORECAST
JUNE 30, 2013
Date Prepared: July 8, 2013

Year	W.T.I.[1]	Edmonton Light[2]	Hardisty Bow River Medium[3]	Western Canadian Select[4]	Hardisty Heavy[5]	Sask. Cromer[6]	Edmonton Propane	Edmonton Butane	Pentane +	Inflation*	U.S./CDN Exchange Rate*
	($U.S./STB)	($CDN/STB)	($CDN/STB)	($CDN/STB)	($CDN/STB)	($CDN/STB)	($CDN/STB)	($CDN/STB)	($CDN/STB)	(%/YR)	($U.S./$CDN)
Historical											
1992	20.56	23.51	17.52	-	12.96	20.52	11.20	14.72	-	1.5	0.829
1993	18.48	22.04	16.70	-	13.26	19.53	14.39	13.61	-	1.8	0.776
1994	17.19	21.88	18.43	-	15.02	20.06	12.57	13.37	-	0.2	0.734
1995	18.40	24.05	20.79	-	17.26	22.05	14.15	13.99	-	1.8	0.729
1996	22.00	29.23	25.03	-	20.06	25.94	22.17	17.13	-	2.1	0.733
1997	20.66	27.65	21.23	-	14.35	23.71	18.59	19.09	-	1.3	0.722
1998	14.42	20.11	14.66	-	9.41	16.95	10.96	11.90	-	1.3	0.674
1999	19.24	27.35	23.35	-	20.42	25.47	15.43	17.74	-	1.4	0.673
2000	30.20	44.33	34.35	-	28.61	40.10	31.55	35.01	46.25	1.5	0.674
2001	25.90	39.18	25.05	-	18.42	32.22	29.19	28.47	42.42	2.0	0.646
2002	26.08	39.94	31.67	-	27.58	34.93	19.87	25.84	40.66	2.1	0.637
2003	31.04	43.17	32.67	-	27.35	37.67	30.15	33.44	44.10	2.2	0.716
2004	41.40	52.54	37.60	-	30.40	45.94	33.39	39.47	55.77	1.8	0.770
2005	56.59	68.72	44.83	-	34.35	57.47	40.29	47.48	77.30	2.0	0.825
2006	66.22	72.77	51.53	51.02	43.27	62.10	40.84	50.84	75.29	1.9	0.882
2007	72.31	76.35	53.36	52.84	44.77	65.68	44.71	51.75	77.33	2.0	0.935
2008	99.65	102.16	84.40	82.92	76.30	93.17	52.03	60.29	104.69	2.4	0.943
2009	61.81	65.90	60.29	58.64	55.65	62.79	38.67	47.73	68.88	0.9	0.880
2010	79.55	77.64	68.48	67.26	62.19	73.76	46.71	68.18	84.23	1.5	0.971
2011	95.12	95.03	78.54	77.10	68.36	88.28	56.38	70.95	104.18	2.9	1.012
2012	94.21	86.29	74.36	73.08	64.97	81.12	30.56	68.64	100.79	1.6	1.001
2013 Q1-Q2	94.30	90.44	71.18	69.86	59.06	N/A	34.07	70.16	105.90	2.0	0.985
Forecast											
2013 Q3-Q4	94.50	91.80	73.80	72.55	65.80	84.80	36.72	68.85	102.80	2.0	0.980
2014	95.00	92.35	75.35	74.35	67.35	85.35	41.55	73.90	103.35	2.0	0.980
2015	95.50	93.35	77.35	76.35	69.35	86.35	46.75	74.70	103.85	2.0	0.980
2016	96.00	94.65	79.65	78.65	70.65	87.65	52.05	75.70	104.65	2.0	0.980
2017	97.00	95.65	80.65	79.65	71.65	88.65	52.60	76.50	105.65	2.0	0.980
2018	98.00	96.70	81.70	80.70	72.70	89.70	53.20	77.40	106.70	2.0	0.980

…escalate prices at 2% per year thereafter…

**Inflation and U.S./CDN Exchange rates kept constant at 2%/year and 1.000 $U.S./$CDN beyond 2018.*

1. at Cushing
2. 40° API; 0.5% sulphur
3. 24.9° API; 2.1% sulphur
4. 20.5° API, 3.2% sulphur
5. 12° API
6. 29° API; 1.2% sulphur

Natural Gas Price Forecast

FEKETE ASSOCIATES INC.
NATURAL GAS PRICE FORECAST
JUNE 30, 2013
($/MMBTU)
Date Prepared: July 8, 2013

			Alberta Plantgate			British Columbia				
Year	Henry Hub Spot	AECO-C Hub	Alberta Gas Reference Price	Progas	Spot	Sumas		Spectra Station 2	Plantgate Spot	Sask. Plantgate Spot
	($U.S.)	($CDN)	($CDN)	($CDN)	($CDN)	($U.S.)	($CDN)	($CDN)	($CDN)	($CDN)
Historical										
1992	1.77	-	1.38	1.55	-	1.16	1.40	-	-	1.17
1993	2.13	-	1.66	1.91	-	1.89	2.44	-	-	2.07
1994	1.92	1.92	1.80	1.92	1.80	1.59	2.18	-	1.87	1.88
1995	1.64	1.19	1.31	1.52	1.07	1.04	1.42	-	1.12	0.99
1996	2.59	1.47	1.63	1.81	1.26	1.32	1.80	-	1.47	1.28
1997	2.59	1.80	1.97	1.98	1.70	-	2.36	-	1.98	1.75
1998	2.11	2.07	2.03	1.95	1.87	1.59	2.37	-	2.00	2.13
1999	2.27	2.92	2.48	2.43	2.75	2.15	3.19	-	2.79	2.87
2000	3.89	5.61	4.50	4.39	5.46	4.15	6.22	-	4.88	5.03
2001	3.96	5.44	5.40	4.99	5.28	3.73	7.01	-	6.28	6.12
2002	3.36	4.07	3.88	4.08	3.91	2.68	4.21	-	3.93	4.09
2003	5.49	6.67	6.17	6.20	6.50	4.74	6.65	-	6.28	6.68
2004	5.90	6.51	6.34	6.32	6.36	5.20	6.67	-	6.30	6.85
2005	8.60	8.79	8.29	8.54	8.63	7.44	8.96	-	8.49	8.44
2006	6.74	6.51	6.56	6.62	6.32	6.03	6.86	-	6.11	7.11
2007	6.98	6.44	6.21	6.37	6.23	6.52	7.00	-	6.24	6.54
2008	8.86	8.15	7.87	8.07	7.90	8.16	8.58	-	7.91	8.18
2009	3.91	3.99	3.87	3.96	3.76	3.75	4.28	-	3.76	4.15
2010	4.39	4.01	3.76	3.83	3.79	4.11	4.24	3.77	3.83	3.91
2011	4.00	3.62	3.45	3.37	3.44	3.87	3.82	3.30	3.24	3.55
2012	2.78	2.39	2.20	1.66	2.19	2.79	2.78	2.38	2.31	2.28
2013 Q1-Q2	3.75	3.37	3.04	2.52	3.17	3.75	3.81	3.32	3.20	3.14
Forecast										
2013 Q3-Q4	4.00	3.60	3.40	2.95	3.40	3.85	3.90	3.50	3.35	3.50
2014	4.25	3.85	3.65	3.45	3.65	4.10	4.15	3.75	3.60	3.75
2015	4.55	4.15	3.95	3.95	3.95	4.40	4.45	4.05	3.90	4.05
2016	5.00	4.60	4.20	4.20	4.20	4.85	4.90	4.50	4.35	4.30
2017	5.35	4.95	4.75	4.75	4.75	5.25	5.30	4.90	4.75	4.85
2018	5.75	5.35	5.15	5.15	5.15	5.60	5.65	5.25	5.10	5.25

...escalate at 2% per year thereafter...

Note: [1.] Years 2002 - 2010 historical aggregator prices shown are prior to receipt transportation deduction.
Forecast prices are Plantgate assuming $0.20/MMBTU receipt transportation deduction.

PART 4 RECONCILIATIONS OF CHANGES IN RESERVES

Item 4.1 Reserves Reconciliation

The following table sets forth the Corporation's total proved, probable and total proved plus probable gross reserves as at June 30, 2013, based on forecast price and cost assumptions.

	Light and Medium Oil			Heavy Oil		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MBbls)	(MBbls)	(MBbls)	(MBbls)	(MBbls)	(MBbls)
June 30, 2012	-	-	-	60.7	9.6	70.3
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Infill Drilling	-	-	-	9.0	1.2	10.2
Technical Revisions	-	-	-	(56.5)	(8.5)	(65.0)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions (neg.)	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production (neg.)	-	-	-	(1.2)	-	(1.2)
June 30, 2013	-	-	-	12.0	2.3	14.3

	Associated and Non-Associated Gas			Natural Gas Liquids		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMCF)	(MMCF)	(MMCF)	(MBbls)	(MBbls)	(MBbls)
June 30, 2012	115	19	134	1.8	0.3	2.1
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Infill Drilling	3	0	3	-	-	-
Technical Revisions	-	-	-	-	-	-
Discoveries	-			-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions (neg.)	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production (neg.)	(3)	0	(3)			
June 30, 2013	115	19	134	1.8	0.3	2.1

Note: Numbers may not add due to rounding.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

The following discussion generally describes the basis on which the Corporation attributes Proved and Proved Plus Probable Undeveloped Reserves and its plans for developing these reserves.

GALILEO PETROLEUMS LTD.
SUMMARY OF COMPANY INTEREST UNDEVELOPED RESERVES
SALT LAKE, SASKATCHEWAN
JUNE 30, 2013

	Light & Medium Oil		Heavy Oil		Natural Gas	
	1st Attributed (MSTB)	Cumulative @ Year End (MSTB)	1st Attributed (MSTB)	Cumulative @ Year End (MSTB)	1st Attributed (MMSCF)	Cumulative @ Year End (MMSCF)
Proved Undeveloped						
2011	-	-	72.0	72.0	115	115
2012			0	49.2 (1)	0	115
2013			0	9.0 (2)	0	115
Proved Plus Probable Undeveloped						
2011	-	-	85.5	85.5	134	134
2012			0	56.2 (1)	0	134
2013			0	10.2 (2)	0	134

Reserves shown are gross working interest before royalty.

(1) Proved and Proved Plus Probable Undeveloped oil reserves were reduced based on the revised deliverability forecassts

(2) Proved and Proved Plus Probable Undeveloped oil reserves were reduced based on the revised deliverability forecast of the 191/12-36-038-25W3 well and the removal of the previously assigned undeveloped reserves for the 111/12-31-038-25W3 and 141/09-36-038-26W3 wells.

Proved Undeveloped Reserves

Proved undeveloped reserves are those reserves tested or indicated by analogy to be productive. All assigned proved undeveloped reserves are planned to be on-stream within a one year timeframe. These reserves represent a conservative estimate.

Probable Undeveloped Reserves

Probable undeveloped reserves are those reserves tested or indicated by analogy to be productive. All assigned probable undeveloped reserves are planned to be on-stream within a one year timeframe. The probable undeveloped reserves represent the difference between our proved plus probable best estimate and our proved conservative estimate.

ITEM 5.2 SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The Corporation's reserves are evaluated by Fekete Associates Inc., an independent engineering firm.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Item 5.3 Future Development Costs

	Prices and Costs	
	Proved	**Proved Plus Probable**
Year	**($000s)**	**($000s)**
2013	0.0	0.0
2014	365.9	365.9
2015	0.0	0.0
2016	0.0	0.0
2017	0.0	0.0
2018	0.0	0.0
Remainder	0.0	0.0
Total Undiscounted	**365.9**	**365.9**

All the capital expenditures were forecast to be spent in 2014.

Sources of Funding

The Company anticipates that the future exploration and development costs will be financed through combinations of internally generated cash flow, debt, flow-through and/or equity financing.

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.1 Oil and Gas Properties and Wells

1. The Corporation's important properties, plants, facilities and installations:

    a) are located exclusively in Canada and more specifically in the Provinces of Alberta and Saskatchewan.
    b) are located onshore.
    c) wells as shown below:

Well Location	Oil/Gas	Property	Status	Comments
111/07-18-038-25W3/00	Gas	Salt Lake	Abandoned	Producing gas zone abandoned; Birdbear oil zone tested and abandoned.
111/07-18-038-25W3/01	Gas	Salt Lake	Compl. Gas Well	No gas reserves assigned.
111/07-18-038-25W3/02	Gas	Salt Lake	Non-Act	Well tested for Birdbear oil production; re-completed in the Waseca gas
111/07-19-038-25W3/02	Gas	Salt Lake	Abandoned	Colony gas tested and abandoned.
111/07-19-038-25W3/03	Oil	Salt Lake	Abandoned	Well tested for Birdbear oil production; abandoned
191/16-30-038-25W3/00	Oil	Salt Lake	Abandoned	Well tested for Birdbear oil production; abandoned
111/01-31-038-25W3/00	Oil	Salt Lake	Non-Act	Former Birdbear oil producer; currently non active well (no reserves assigned). Uphole gas potential. Gas reserves assigned.
191/12-36-038-26W3/00	Oil	Salt Lake	Producing	Birdbear oil reserves assigned.
192/12-36-038-26W3/00	Oil	Salt Lake	Non Producing	No oil reserves assigned.
100/01-11-044-21W4/00	Oil	Ferintosh	Drilled and Cased	Unsuccessful fracure stimulation performed. Well shut-in.

2. The number of the Corporation's oil wells and gas wells producing and non-producing expressed on a gross and net basis, by location, is as follows:

	Oil Wells				Gas Wells			
	Producing		Non Producing		Producing		Non Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Saskatchewan, Canada	1	0.25	2	0.5	0	0	1	0.25
Alberta, Canada	0	0	1	0.285	0	0	0	0

Item 6.2 Properties with No Attributed Reserves

a. The Corporation has interests in the following lands with a gross area of 5,922 hectares or 14,633.1 acres.

Wi Lands	Gross Area	Company WI	Net Area
	(ha)	%	(ha)
Border, Alberta	96	100.0	96.0
Ferintosh, Alberta	4,994	28.5	1,423.2
Provost, Alberta	832	50.0	416.0
	5,922		1,935.2

b. The Border, Ferintosh and Provost lands are located in Canada in the Province of Alberta.

c. There are no wells drilled and no reserves assigned at Border and Provost, Alberta.

d. The Corporation has an exploration well drilled and cased at the Ferintosh property. The Corporation is committed to completing and testing the exploration well. A recent fracture stimulation treatment was performed by a third party, however, it was unsuccessful. Currently, the well is shut-in.

e. The acreage also has some deeper hydrocarbon potential. There are plans to either acquire or shoot seismic across the prospective lands.

Item 6.3 Forward Contracts

1. The Corporation is not bound by any agreements under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas.

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs

a) The estimate of costs is determined through a review of industry guidelines.

b) The number of net wells for which the Corporation expects to show such costs is 0.75 (0.25 producing well, 0.25 well that is to be drilled in 2014 and one re-completion well in 2014).

c) An estimate of abandonment and reclamation costs, net of salvage:

   a. Total Proved Case
      i. Undiscounted: $51.9M
      ii. Discounted at 10%: $30.2M
   b. Total Proved Plus Probable Case
      i. Undiscounted: $52.3M
      ii. Discounted at 10%: $28.9 M

d) The entire amount disclosed in (c) herein was deducted as abandonment and reclamation costs in estimating the Corporation's future net revenue.

e) The portion of the amounts disclosed in (c) herein that the Corporation expects to pay in the next three financial years is $0M or 0%.

Item 6.5 Tax Horizon

The Company is not expected to pay corporate income taxes in 2013. Based on current estimated reserves and forecasted future production, the Corporate tax pools are such that no Corporate income tax would be payable.

Item 6.6 Costs Incurred

The capital expenditures incurred for year ended June 30, 2013, are shown below:

Property Acquisition	-
Exploration	$9,767
Development	$12,674
Total	**$22,441**

Item 6.7 Exploration and Development Activities

1. In the Corporation's financial year ended June 30, 2013, the number of wells completed are as follows:

		Gross		Net	
Canada	Exploratory Wells	Dry Oil Gas Service	0 0 0 0	Dry Oil Gas Service	0 0 0 0
	Development Wells	Dry Oil Gas Service	0 0 1 0	Dry Oil Gas Service	0 0 0.25 0

The Corporation's most important exploration and development activities are located in the Salt Lake property, Saskatchewan, Canada.

Item 6.8 Production Estimates

1. All of the Corporation's properties are located in Canada. The Corporation's production volume estimates as reflected in the estimates of future net revenue disclosed herein are as follows:

Estimated First Year Production—Total Corporation

	Gross Cumulative Production			Net Cumulative Production		
	Light, Medium and Heavy Crude Oil	Natural Gas	Natural Gas Liquids	Light, Medium and Heavy Crude Oil	Natural Gas	Natural Gas Liquids
	(MBbls)	(MMCF)	(MBbls)	(MBbls)	(MMCF)	(MBbls)
Proved						
Developed Producing	0.5	-	-	0.5	-	-
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-
Total Proved	0.5	-	-	0.5	-	-
Probable	-	-	-	-	-	-
Total Proved plus Probable	0.5	-	-	0.5	-	-

2. The Salt Lake property accounts for 100% of the estimated production disclosed under Section 1.

Item 6.9

The following sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Corporation for the most recent completed financial period:

Net Average Daily Production	**Q1**	**Q2**	**Q3**	**Q4**
Oil & NGL (Bbls/d)	4.4	2.8	4.1	2.4
Gas (Mcf/d)	0	22	13	10
BOE/D (6:1)	4.4	6.4	6.3	4.1
Prices				
Oil & NGL ($/ Bbl)	60.1	59.4	44.8	65.6
Gas ($/Mcf)	0	3.1	3.1	3.5
BOE ($/BOE)	60.1	47.8	37.5	61.5
Royalties ($/BOE)	1.5	0.9	0.9	0.9
Production Costs ($/BOE)	23.6	25.1	25.9	27.2
Netback ($/BOE)	35.0	21.8	10.7	33.4