BIRCHCLIFF ENERGY LTD.

Year Ended December 31, 2013

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

March 12, 2014

DATE OF STATEMENT

Relevant Dates

This Statement of Reserves Data and Other Oil and Gas Information of Birchcliff Energy Ltd. ("**Birchcliff**" or the "**Corporation**") is dated March 12, 2014. The effective date of the reserves and future net revenue information provided is December 31, 2013, unless otherwise indicated. The preparation date in respect of the disclosures contained herein is March 12, 2014.

DISCLOSURE OF RESERVES DATA

Independent Qualified Reserves Evaluator

Deloitte LLP ("**Deloitte**"), independent qualified reserves evaluators of Calgary, Alberta prepared a Reserves Estimation and Economic Evaluation effective December 31, 2013 in respect of the Corporation's oil and natural gas properties, which is contained in a report dated February 5, 2014 (the "**2013 Reserves Evaluation**"). Deloitte has confirmed to the Reserves Evaluation Committee of The Corporation's Board of Directors that the 2013 Reserves Evaluation has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("**COGE Handbook**") and National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

In preparing its report, Deloitte obtained basic information from the Corporation, which included land data, well and accounting information, reservoir and geological studies, estimates of on-stream dates for certain properties, contract information, budget forecasts and financial data. Other engineering, geological or economic data required to conduct the evaluation, and upon which the 2013 Reserves Evaluation is based, were obtained from public records, other operators and from Deloitte's non-confidential files. The extent and character of ownership and all factual data supplied to Deloitte by the Corporation were accepted by Deloitte as presented.

For the purposes of properly understanding the reserves and future net revenue data presented from Deloitte's Evaluation, it is important to understand each of the following:

- The net present value of future net revenue attributable to the Corporation's reserves is based on Deloitte's December 31, 2013 forecast price assumptions set out in Table 5 ("**Deloitte Price Forecast**") and was determined without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, transportation and marketing costs, development costs, other income, future capital expenditures and well abandonment and reclamation costs for wells that were evaluated by Deloitte in the 2013 Reserves Evaluation.
- Well reclamation costs used by Deloitte were not independently evaluated and were assumed to be equal to the average costs for the Corporation's regional reclamation cost area set forth in Directive 11 from the Alberta Energy Regulator.
- 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 Deloitte, represent the fair market value of those reserves.
- The recovery and reserve estimates of the Corporation's oil, natural gas liquids 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. Reservoir performance after December 31, 2013 may justify revision of assessed reserves, either upward or downward.

- The tables below are a summary of the oil, natural gas liquids and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the 2013 Reserves Evaluation based on the Deloitte Price Forecast. The tables summarize the data contained in the 2013 Reserves Evaluation.
- The 2013 Reserves Evaluation is based on certain factual data supplied by the Corporation and Deloitte'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 the Corporation to Deloitte and accepted without any further investigation. Deloitte accepted this data as presented and neither title searches nor field inspections were conducted.
- Estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Reserves Summary (Forecast Prices and Costs)

All of the Corporation's reserves are in Canada, specifically, in the Peace River Arch area in the Province of Alberta.

The following table summarizes Deloitte's estimates of the Corporation's oil and natural gas reserves at December 31, 2013, using the Deloitte Price Forecast.

Table 1

Summary of Oil and Natural Gas Reserves at December 31, 2013
(Forecast Prices and Costs)

	Light and Medium Oil *(Mbbl)*		**Natural Gas[1]** *(Bcf)*		**Natural Gas Liquids** *(Mbbl)*		**Total Boe** *(Mboe)*	
Reserves Category	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Proved								
Developed Producing	6,235.0	5,192.6	320.8	294.5	2,253.6	1,556.8	61,951.4	55,835.3
Developed Non-Producing	2,912.7	2,304.4	20.3	18.1	147.6	96.8	6,447.9	5,419.8
Undeveloped	8,473.3	6,611.7	823.6	757.2	5,912.1	4,415.3	151,650.2	137,227.2
Total Proved	17,621.0	14,108.7	1,164.7	1,069.8	8,313.2	6,068.8	220,049.4	198,482.3
Probable	18,201.3	14,344.7	755.9	686.7	5,813.5	4,020.6	150,002.8	132,814.6
Total Proved Plus Probable	35,822.3	28,453.3	1,920.6	1,756.5	14,126.8	10,089.4	370,052.2	331,296.9

(1) Estimates of reserves of natural gas include associated and non-associated gas.

Net Present Value of Future Net Revenue (before and after income tax)

The following table is a summary of the net present value of future net revenue associated with the Corporation's reserves at December 31, 2013, using the Deloitte Price Forecast, before and after deducting future income tax expense, and calculated at various discount rates.

Table 2

Net Present Value of Future Net Revenue(1)(2(3)) at December 31, 2013

	Discounted At					
(Forecast Prices and Costs) (MM$) (per year)	0%	5%	8%	10%	15%	20%
BEFORE INCOME TAXES						
Proved						
Developed Producing	1,643.7	1,220.0	1,057.3	972.2	813.3	703.9
Developed Non-Producing	255.5	188.6	161.8	147.5	120.1	101.0
Undeveloped	3,175.8	1,725.2	1,220.5	971.9	544.0	284.0
Total Proved	5,074.9	3,133.8	2,439.6	2,091.5	1,477.5	1,088.9
Probable	4,920.2	2,191.2	1,437.3	1,106.8	606.7	350.2
Total Proved Plus Probable	9,995.2	5,325.0	3,876.9	3,198.3	2,084.1	1,439.1
AFTER INCOME TAXES						
Proved						
Developed Producing	1,537.6	1,165.3	1,019.4	942.2	795.9	693.4
Developed Non-Producing	191.7	147.2	129.2	119.5	100.7	87.2
Undeveloped	2,379.8	1,259.3	867.7	674.5	341.8	139.7
Total Proved	4,109.1	2,571.8	2,016.3	1,736.2	1,238.4	920.3
Probable	3,690.1	1,620.2	1,048.2	797.9	420.5	229.1
Total Proved Plus Probable	7,799.2	4,192.0	3,064.5	2,534.1	1,659.0	1,149.4

(1) Estimates of future net revenue, whether discounted or not, do not represent fair market value.
(2) Future net revenue is after deduction of estimated costs of abandonment and reclamation of existing and future wells that were evaluated by Deloitte in the 2013 Reserves Evaluation and does not include costs of abandonment and reclamation of facilities.
(3) Numbers may not total due to rounding.

Elements of Future Net Revenue

The following table sets out, in the aggregate, the various elements of the Corporation's future net revenue associated with the Corporation's reserves as estimated by Deloitte at December 31, 2013, calculated using the Deloitte Price Forecast and without discount.

Table 3

Elements of Future Net Revenue[(1)(2)] at December 31, 2013

(Forecast Prices and Costs) (Undiscounted)

(MM$)	Future Net Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs[(2)]	Future Net Revenue Before Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenue After Future Income Tax Expenses
Proved								
Developed Producing	2,559.3	280.8	579.2	1.3	54.3	1,643.7	106.1	1,537.6
Developed Non-Producing	392.6	71.3	56.2	9.2	0.4	255.5	63.8	191.7
Undeveloped	6,509.2	677.0	1,173.5	1,444.1	38.8	3,175.8	796.0	2,379.8
Total Proved	9,461.0	1,029.1	1,809.0	1,454.5	93.5	5,074.9	965.9	4,109.1
Probable	8,616.3	1,023.4	1,576.5	1,050.1	46.0	4,920.2	1,230.1	3,690.1
Total Proved Plus Probable	18,077.3	2,052.5	3,385.5	2,504.6	139.5	9,995.2	2,196.0	7,799.2

(1) Estimates of future net revenue, whether discounted or not, do not represent fair market value.

(2) Future net revenue is after deduction of estimated costs of abandonment and reclamation of existing and future wells that were evaluated by Deloitte in the 2013 Reserves Evaluation and does not include costs of abandonment and reclamation of facilities.

Net Present Value of Future Net Revenue by Production Group (before Income Tax)

The following table sets forth by production group, the future net revenue associated with the Corporation's reserves at December 31, 2013, before deducting future income tax expenses and calculated using a 10% discount rate.

Table 4

Net Present Value Of Future Net Revenue[(1)(2)] at December 31, 2013

(Forecast Prices and Costs) (Before Income Tax) (10% Discount Rate)

	Light and Medium Oil[(3)]		Natural Gas[(3)]	
	(MM$)	*($/boe)[(4)]*	*(MM$)*	*($/boe)[(4)]*
Proved				
Developed Producing	266.0	34.0	706.3	14.7
Developed Non-Producing	116.3	42.7	31.4	11.7
Undeveloped	170.1	20.2	804.9	6.2
Total Proved	552.5	29.1	1,542.7	8.6
Probable	363.0	18.2	743.9	6.6
Total Proved Plus Probable	915.4	23.5	2,286.6	7.8

(1) Estimates of future net revenue, whether discounted or not, do not represent fair market value.

(2) Future net revenue is after deduction of estimated costs of abandonment and reclamation of existing and future wells that were evaluated by Deloitte in the 2013 Reserves Evaluation and does not include costs of abandonment and reclamation of facilities.

(3) Estimates of reserves include associated and non-associated gas and by-products. The production groupings are determined based upon the primary product produced from each reserve entity. The values and volumes of associated gas and the by-products derived from such associated gas are included with oil. The values and volumes of the by-products derived from non-associated gas are included with natural gas.

(4) Unit amounts are derived using net reserves volumes.

PRICING ASSUMPTIONS

Forecast Prices Used in Estimates

The following table sets forth the forecast price assumptions used by Deloitte for the 2013 Reserves Evaluation. The pricing and cost assumptions used were determined by Deloitte using information available from numerous governmental agencies, industry publications, oil refineries, natural gas marketers and industry trends. These long-term forecasts of prices are subject to the many uncertainties that effect long-term future forecasts.

Table 5

Deloitte Price Forecast

	Crude Oil		Natural Gas	Natural Gas Liquids				
Year	WTI Crude Oil *($US/bbl)*	Edmonton City Gate *($CDN/bbl)*	Natural Gas at AECO *($CDN/Mcf)*	Edmonton Propane *($CDN/bbl)*	Edmonton Butane *($CDN/bbl)*	Edmonton C5+ *($CDN/bbl)*	Currency Exchange Rate *($US/$CDN)*	Inflation Rate *(%)*
2014	95.00	95.75	3.70	33.50	76.60	105.35	0.94	0.0
2015	91.80	92.30	3.95	32.30	73.85	101.55	0.94	2.0
2016	91.55	95.20	4.10	52.35	76.15	104.70	0.94	2.0
2017	91.25	94.80	4.30	52.15	75.85	104.30	0.94	2.0
2018	92.00	95.60	4.55	52.60	76.50	105.15	0.94	2.0
2019	93.85	97.50	4.85	53.65	78.00	107.25	0.94	2.0
2020	95.70	99.45	5.25	54.70	79.55	109.40	0.94	2.0
2021	97.65	101.45	5.70	55.80	81.15	111.60	0.94	2.0
2022	99.60	103.45	6.10	56.90	82.75	113.80	0.94	2.0
2023	101.60	105.55	6.45	58.05	84.45	116.10	0.94	2.0
Thereafter	Escalate at 2.0% per annum							

Actual Weighted Average Commodity Prices

The actual weighted average commodity prices received by the Corporation in 2013 are as follows:

- Crude Oil: $89.89 per bbl
- Natural Gas: $3.41 per Mcf
- Natural Gas Liquids: $88.45 per bbl

RECONCILIATION OF CHANGES IN RESERVES

The following tables set forth a reconciliation of the Corporation's gross reserves at December 31, 2013 set forth in the 2013 Reserves Evaluation, using the Deloitte price forecast at December 31, 2013, to the Corporation's gross reserves at December 31, 2012 set forth in the 2012 Reserves Evaluation, using the Deloitte price forecast at December 31, 2012.

Table 6

Reconciliation of Gross Reserves, from December 31, 2012 to December 31, 2013

(Forecast Prices and Costs)	**Light and Medium Crude Oil** *(Mbbl)*	**Natural Gas** *(Bcf)*	**NGLs** *(Mbbl)*	**Oil Equivalent** *(Mboe)*
GROSS TOTAL PROVED				
Opening balance December 31, 2012	**20,018.6**	**961.8**	**5,624.9**	**185,950.0**
Discoveries	0.0	0.0	0.0	0.0
Extensions(1) & Improved Recovery	1,750.5	252.2	1,767.6	45,556.7
Infill Drilling	0.0	0.0	0.0	0.0
Technical Revisions(2)	-174.4	-5.0	1,218.8	202.8
Acquisitions	0.0	0.0	0.0	0.0
Dispositions	-2,292.3	0.0	0.0	-2,292.3
Economic Factors(3)	29.4	1.1	3.6	223.9
Production(4)	-1,710.8	-45.5	-301.7	-9,591.8
Closing balance December 31, 2013	**17,621.0**	**1,164.7**	**8,313.2**	**220,049.4**
GROSS PROBABLE				
Opening balance December 31, 2012	**15,874.7**	**668.7**	**4,489.8**	**131,819.9**
Discoveries	0.0	0.0	0.0	0.0
Extensions(1) & Improved Recovery	2,439.4	86.1	1,124.8	17,911.9
Infill Drilling	0.0	0.0	0.0	0.0
Technical Revisions(2)	1,227.2	-0.1	189.2	1,407.0
Acquisitions	469.1	0.6	6.9	569.8
Dispositions	-1,820.1	0.0	0.0	-1,820.1
Economic Factors(3)	11.0	0.6	2.9	114.5
Production(4)	0.0	0.0	0.0	0.0
Closing balance December 31, 2013	**18,201.3**	**755.9**	**5,813.6**	**150,002.9**
GROSS TOTAL PROVED PLUS PROBABLE				
Opening balance December 31, 2012	**35,893.3**	**1,630.6**	**10,114.7**	**317,770.0**
Discoveries	0.0	0.0	0.0	0.0
Extensions(1) & Improved Recovery	4,189.9	338.3	2,892.4	63,468.5
Infill Drilling	0.0	0.0	0.0	0.0
Technical Revisions(2)	1,052.8	-5.1	1,408.0	1,609.7
Acquisitions	469.1	0.6	6.9	569.8
Dispositions	-4,112.4	0.0	0.0	-4,112.4
Economic factors(3)	40.4	1.7	6.5	338.4
Production(4)	-1,710.8	-45.5	-301.7	-9,591.8
Closing balance December 31, 2013	**35,822.3**	**1,920.6**	**14,126.8**	**370,052.2**

(1) The majority of reserve changes comprising "Extensions" were the result of drilling activities in the Montney/Doig Natural Gas Resource Play. Wells were drilled extending the resource play beyond lands to which reserves had previously been attributed. As a result of these successful wells, reserves were attributed to future well locations proximal to these wells.

(2) The majority of the "Technical Revisions" are a result of a change in the well type curves used by Deloitte for Birchcliff's liquid rich gas wells and Montney oil wells in certain areas, and the better performance of some Charlie Lake oil wells at Worsley.

(3) The change in reserves attributed to "Economic Factors", results from Deloitte's natural gas prices forecast used in the 2013 Reserves Evaluation being lower than Deloitte's natural gas prices forecast used in the 2012 Reserves Evaluation, increasing the time to payout of a non-participating partner's penalty wells and thereby adding working interest gas reserves for Birchcliff's account.

(4) Represents Deloitte's estimate of actual production for the year ended December 31, 2013 before year-end results were available.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following table sets forth the volumes of each of the proved undeveloped reserves and the probable undeveloped reserves from the applicable reserves evaluation for such year for each product type that were first attributed as reserves in each of the most recent three financial years and in the aggregate, before that time.

Table 7

Undeveloped Reserves

	Proved Undeveloped Reserves			Probable Undeveloped Reserves		
Year of first attribution	**Light and Medium Crude Oil** *(Mbbl)*	**Natural Gas** *(MMcf)*	**Natural Gas Liquids** *(Mbbl)*	**Light and Medium Crude Oil** *(Mbbl)*	**Natural Gas** *(MMcf)*	**Natural Gas Liquids** *(Mbbl)*
2013	894	154,141	924	2,901	70,102	948
2012	1,323	229,087	1,243	465	29,515	161
2011	1,401	170,556	1,076	569	42,587	251
Aggregate attributed in prior years	4,855	269,805	2,669	10,060	529,809	3,825

The Corporation has a large inventory of development opportunities in its portfolio and its capital spending activities are prioritized to optimize development plans, achieve strategic goals and maximize shareholder value.

There are 310 (267.3 net) future horizontal well locations to which the 2013 Reserves Evaluation has attributed proved undeveloped reserves.

Approximately 93% of the proved undeveloped reserves are attributed to the Montney/Doig Natural Gas Resource Play, and the 2013 Reserves Evaluation has attributed proved undeveloped reserves to each future horizontal well location that is proximal to an existing well to which Deloitte has attributed proved developed reserves. Deloitte has estimated such proved undeveloped reserves using forecast production rates that are based on a statistical analysis of production rates of existing wells operated by the Corporation or others on the Montney/Doig Natural Gas Resource Play in the regional area.

There are 266 (255 net) future horizontal well locations in the Montney/Doig Natural Gas Resource Play to which the 2013 Reserves Evaluation has attributed proved undeveloped reserves. In the 2013 Reserves Evaluation, Deloitte forecast that 31.4 net wells and 63.4 net wells would be drilled in 2014 and 2015 respectively. The Corporation anticipates that drilling activities in 2014 will utilize existing and expansion capacity available at the PCS Gas Plant totalling 180 MMcf/day. In 2015, the Corporation will continue to develop its proved undeveloped reserves on the Montney/Doig Natural Gas Resource Play as processing capacity becomes available from expanded and new processing plants operated by the Corporation or from third party plants.

Approximately 5.5% of the proved undeveloped reserves are attributed to the Corporation's Worsley Charlie Lake Light Oil Resource Play and of those, approximately 60% are based on Deloitte's forecast of increased recoveries from the waterflood enhanced recovery scheme that has been underway for a number of years and Deloitte's forecast areal expansion of the waterflood. During 2014 and 2015, the Corporation will develop a portion of these undeveloped reserves by the drilling of new wells and the conversion of existing wells to water injection wells.

The balance of the proved undeveloped reserves attributed by Deloitte to the Worsley Charlie Lake Light Oil Resource Play relate in part to 42 (41.1 net) future drilling locations. The Corporation is planning to develop approximately 20 (20.0 net) of these future drilling locations prior to the end of 2015 to the extent that their production can be accommodated at the Corporation's current Worsley facilities. The balance of these future drilling locations will be developed, thereafter, as processing capacity becomes available.

With respect to the probable undeveloped reserves, on both the Montney/Doig Natural Gas Resource Play and the Worsley Charlie Lake Light Oil Resource Play, the Corporation's development plans are largely dependent on the development of the proved undeveloped reserves discussed above. The development of the probable undeveloped reserves is planned to occur during the ensuing three years, on a schedule consistent with the Corporation's access to required processing capacity.

The Corporation's plans relating to the development of its proved undeveloped reserves and its probable undeveloped reserves and the timing of such development may change based on changes in geological, geophysical, engineering data and commodity prices that become available to the Corporation and upon the characteristics of other potential investments that become available to the Corporation in its areas of interest and elsewhere.

Significant Factors or Uncertainties Affecting Reserves Data

There are a number of uncertainties inherent in estimating the quantities of reserves and resources, including many factors beyond the control of the Corporation. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom, are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineer at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Corporation with respect to these reserves will vary from such estimates, and such variances could be material.

Estimates with respect to proved plus probable reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves. Consistent with the securities disclosure legislation and policies of Canada, the Corporation has used forecast prices and costs in calculating reserve quantities. Actual future net cash flows also will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulations or taxation and the impact of inflation on costs.

The reserve estimates contained herein are based on Deloitte's production forecasts, prices and economic conditions at the time of preparation of the 2013 Reserves Evaluation. The factors and assumptions that affect these reserve estimates include, among other things: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

Future Development Costs

The following table sets forth the future development costs that have been deducted in the estimation of future net revenue attributable to the Corporation's reserves estimated by Deloitte in the 2013 Reserves Evaluation using the Deloitte Price Forecast and calculated without discount.

Table 8

Future Development Costs

(Forecast Prices and Costs) (MM$)	**Proved**	**Proved Plus Probable**
2014	220.1	237.1
2015	408.4	472.3
2016	342.5	407.7
2017	285.3	346.5
2018	197.7	355.3
2019	0.2	283.8
Thereafter	0.3	402.0
Total undiscounted	1,454.5	2,504.6

The Corporation expects to be able to fund the development costs required in the future from working capital, internally generated cash flow, existing credit facilities and access to debt. Interest and other costs of external funding are not included in the future net revenue estimates. The Corporation does not expect any inordinate costs to be associated with such funding sources.

There can be no guarantee that funds will be available or that the Corporation will allocate funding to develop all of the reserves attributed in the 2013 Reserves Evaluation. Failure to develop those reserves would have a negative impact on future production and cash flow estimated by Deloitte.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

The Corporation's important properties and facilities are described in its Annual Information Form into which this Statement of Reserves Data and Other Oil and Gas Information is incorporated by reference.

Producing and Non-Producing Wells

The following table shows the Corporation's producing and non-producing oil and natural gas wells at December 31, 2013, all of which are in Alberta.

Table 9

Producing and Non-Producing Wells(1) at December 31, 2013

	OIL WELLS				**NATURAL GAS WELLS**			
	Producing		**Non-producing**		**Producing**		**Non-producing**	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Alberta	230	193.5	96	73.4	190	167.9	130	83.2

(1) Does not include water injection wells, service wells, capped wells and wells that have not been categorized as either oil wells or natural gas wells.

Properties with No Attributed Reserves

At December 31, 2013, the Corporation held 576,893 (544,917 net) acres of undeveloped land. The Corporation has 110,194 (110,194 net) acres where the rights to explore, develop and exploit are expected to expire prior to the end of 2014. The Corporation expects that its planned operations will continue its tenure with respect to approximately 46% of this expiring acreage, primarily where it recognizes the most value. None of the planned operations are subject to any work commitments.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

There are several economic factors and significant uncertainties that affect the anticipated development of the Corporation's properties with no attributed reserves. The Corporation will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil and natural gas from these properties in the future. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, that the terms will be acceptable to the Corporation. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain opportunities and reduce its development. The inability of the Corporation to access sufficient capital for its exploration and development purposes could have a material adverse effect on the Corporation's ability to execute its business strategy to develop its prospects. See also the Corporation’s Annual Information Form under the heading “*Risk Factors*”.

The significant economic factors that affect the Corporation’s development of its lands to which no reserves have been attributed are future commodity prices for crude oil and natural gas (and the Corporation’s outlook relating to such prices), the future costs of drilling, completing, tying in and operating wells at the relevant times.

The significant uncertainties that affect the Corporation’s development of its lands are the future drilling and completion results the Corporation achieves in its development activities, drilling and completion results achieved by others on lands in proximity to the Corporation’s lands and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. On the other hand, uncertainty as to the timing and nature of the evolution or development of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to the development of such lands.

Forward Contracts

The Corporation has entered into certain commodity price risk management contracts for 2014 in order to reduce volatility in its financial results and protect its cash flow and capital expenditure program. Birchcliff’s current strategy is to hedge a portion of its oil and natural gas using a combination of financial derivatives and physical delivery sales contracts to manage commodity risk.

Financial derivatives

The Corporation had entered into the following financial derivative contracts at December 31, 2013.

Table 10

Product	Option traded	Notional quantity	Term	Strike price	Fair value *($000's)*
Crude oil	Put option	500 bbls/day	January 1, 2014 – December 31, 2014	WTI USD $90/bbl	507
Crude oil	Put option	500 bbls/day	January 1, 2014 – December 31, 2014	WTI USD $85/bbl	319
Total fair value assets(1)					**826**

(1) The Corporation also recorded approximately $1.2 million as a deferred premium on financial instruments, which represents the amount payable to the counterparty to these contracts at December 31, 2013.

The fair value of these risk management assets at December 31, 2013 was approximately $0.8 million (2012 – NIL). As of December 31, 2013, if the future strip prices for WTI crude oil had been $1.00 USD per bbl higher, with all other variables held constant, after tax net income would have been $0.04 million (2012 - NIL) lower.

The following table provides a summary of the unrealized losses on financial instruments.

Table 11

	Three months ended December 31,		**Twelve months ended December 31,**	
($000's)	**2013**	**2012**	**2013**	**2012**
Unrealized loss on financial instruments	379	-	379	-
Unrealized loss on financial instruments	**379**	-	**379**	-

There were no financial derivative contracts entered into subsequent to December 31, 2013.

Physical sales contracts

Physical delivery sales contracts are considered sales contracts in the normal course of operations and are not recorded at fair value in the financial statements. The Corporation had entered into the following physical contracts at December 31, 2013.

Table 12

Product	Type of contract	Volume	Term(1)	Contract price
Natural gas	AECO fixed price	40,000 GJ/day	April 1, 2014 to October 31, 2014	$3.68 CDN/GJ

(1) Transactions with common terms have been aggregated and presented as the weighted average price.

The Corporation has entered into the following physical contract subsequent to December 31, 2013.

Table 13

Product	Type of contract	Volume	Term(1)	Contract price
Natural gas	AECO fixed price	35,000 GJ/day	April 1, 2014 to October 31, 2014	$3.98 CDN/GJ

(1) Transactions with common terms have been aggregated and presented as the weighted average price.

Birchcliff's total natural gas hedge position for 2014 is summarized below.

Table 14

Product	Term[(1)]	Average production hedged[(2)]	Estimated average wellhead price[(2)]
Natural gas	April 1, 2014 to October 31, 2014	65,908 Mcf/day	$4.35 CDN/Mcf

(1) Transactions with common terms have been aggregated and presented as the weighted average price.

(2) The conversion from GJ to Mcf is based on an estimated average natural gas heat content for Birchcliff's Pouce Coupe area of 40.4 MJ/m^3.

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation estimates the future costs for abandonment and reclamation of surface leases, wells and facilities by using amounts that are consistent with Directive 11 of the Alberta Energy Regulator, which provides ranges of typical costs for abandonment and reclamation experienced by the industry in the Corporation's areas of operation. Based on this information and the actual experience of its technical personnel in handling such matters in the past, the Corporation estimates its typical abandonment costs to be in the range of $61,000 to $65,000 per well depending on the specific circumstances. Reclamation costs are forecast at approximately $30,000 per wellsite. Costs of abandoning pipelines are estimated by the Corporation on a case by case basis relying on the knowledge and experience of its technical personnel.

The 2013 Reserves Evaluation has included estimated well abandonment costs for all existing wells and future drilling locations identified in the 2013 Reserves Evaluation, but reclamation costs have been included only for future drilling locations.

The Corporation currently has 647 net wells that ultimately will need to be abandoned and/or reclaimed.

The following table sets forth the total amount of future costs to be incurred by the Corporation in connection with the abandonment and reclamation of wells in the proved and proved plus probable categories at December 31, 2013.

Table 15

Future Abandonment and Reclamation Costs Relating to Proved and Proved Plus Probable Reserves

	Undiscounted Amount		Discounted Amount at 10% per year	
(Forecast Pricing and Costs) ($000)	**Proved**	**Proved Plus Probable**	**Proved**	**Proved Plus Probable**
Total amount of the future abandonment and reclamation costs, net of salvage value estimated by Deloitte to be incurred	93,509	139,476	25,350	24,946
Portion not deducted as abandonment and reclamation costs, in determining future net revenue[(1)]	43,417	55,730	12,251	5,456
Portion that the Corporation expects to pay in the next three years	6,900	6,900	1,871	1,871

(1) Includes estimated abandonment and reclamation costs for facility sites and pipelines.

Tax Horizon

The Corporation was not required to pay any cash income taxes for the year ended December 31, 2013. The Corporation estimates that based on current expenditure plans and the current price environment, no income taxes will become payable on the Corporation's income during 2014. If the Corporation continues to expend capital beyond its internally generated funds flow, it is likely that the Corporation will not become taxable within the next five years as long as such expenditures continue and commodity prices remain consistent with today's environment.

Costs Incurred

The following table sets forth the Corporation's property acquisition costs for proved properties and unproved properties, exploration costs and development costs for the year ended December 31, 2013.

Table 16

2013 Acquisition, Exploration and Development Costs

Acquisition Costs			
Proved Properties *($000)*	**Unproved Properties** *($000)*	**Exploration Costs** *($000)*	**Development Costs** *($000)*
0.3	450.9	24,361	243,757

Exploration and Development Activities

The following table sets forth a summary of the Corporation's exploration and development drilling activities for the year ended December 31, 2013.

Table 17

2013 Exploration and Development Activities

	Exploration Wells		**Development Wells**		**Total**	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*
Oil Wells	2	2	15	13.7	17	15.7
Natural Gas Wells	5	5	21	21	26	26
Service Wells	–	–	–	–	–	–
Stratigraphic Test Wells	–	–	–	–	–	–
Dry Holes	–	–	–	–	–	–
Total	7	7	36	34.7	43	41.7

The Corporation's most important current and likely exploration and development activities will focus on the drilling and completion of wells on the Montney/Doig Natural Gas Resource Play and the Worsley Charlie Lake Light Oil Resource Play.

Production Estimates

The following table sets forth Deloitte's forecast volumes of the Corporation's production from gross proved reserves and gross probable reserves as estimated in the 2013 Reserves Evaluation for the year ended December 31, 2013.

Table 18

2014 Production Volume Estimates

	Light and Medium Crude Oil *(Mbbl)*	**Natural Gas** *(Bcf)*	**NGLs** *(Mbbl)*	**Oil Equivalent** *(Mboe)*
Gross Total Proved	1,773.0	65.0	440.5	13,006.8
Gross Probable	162.7	0.9	7.4	320.1

The estimated production volumes for the field that accounts for more than 20% of Deloitte's total forecast production for the 2013 year is set forth below.

Table 19

2014 Production Volume Estimates for Important Field

	Deloitte Forecast Production	
Field Name	**Gross Proved Reserves** *(Mboe)*	**Gross Probable Reserves** *(Mboe)*
Pouce Coupe South	9,270.8	40.9

Production History

2013 Average Daily Production by Product Type

The following table sets out, by product type, the Corporation's average gross daily production volumes, quarterly and for the year ended December 31, 2013.

Table 20

2013 Quarterly Production History

	Three months ended				Year ended
Product Type	**March 31, 2013**	**June 30, 2013**	**September 30, 2013**	**December 31, 2013**	**December 31, 2013**
Light and Medium Crude Oil *(bbls/day)*	4,047	3,941	3,903	4,227	4,030
Natural Gas *(Mcf/day)*	128,101	116,963	119,608	138,132	125,712
NGLs *(bbls/day)*	710	706	824	1,142	847
Total *(boe/day)*	26,108	24,141	24,662	28,391	25,829

2013 Annual Production by Product Type

The following table sets forth the Corporation's annual production volumes for the year ended December 31, 2013 by product type, for the fields comprising more than 10% of the Corporation's total production.

Table 21

2013 Production Volumes

	Light and Medium Crude Oil *(bbls)*	**Natural Gas** *(Mcf)*	**NGLs** *(bbls)*	**Oil Equivalent** *(boe)*
Worsley	1,171,638	2,828,333	35,830	1,678,857
Pouce Coupe South	4,998	33,692,581	192,532	5,812,960
Total Annual Production Volumes[1]	1,470,816	45,884,734	309,133	9,427,404

(1) Total actual annual production volumes provided by Birchcliff.

2013 Price Received, Royalties Paid, Production Costs and Netbacks

The following table sets forth, by product type, the Corporation's share of average daily production before deduction of royalties, the prices received, royalties paid, production costs incurred and the resulting netback on a per unit of volume basis, quarterly and for the year ended December 31, 2013.

Table 22

2013 Quarterly Price, Royalty, Production Cost and Netback History

	Three months ended				Year ended
	March 31, 2013	**June 30, 2013**	**September 30, 2013**	**December 31, 2013**	**December 31, 2013**
Light and Medium Crude Oil *($/bbl)*					
Price Received [1]	84.82	91.19	102.82	81.52	89.89
Royalties Paid	(13.05)	(15.21)	(18.04)	(13.05)	(14.79)
Production Costs	(9.76)	(11.40)	(9.97)	(10.65)	(10.46)
Transportation and Marketing	(6.83)	(7.72)	(6.74)	(8.03)	(7.35)
Netback	55.18	56.86	68.07	49.79	57.29
Royalty Income	0.07	1.48	0.02	0.02	0.40
Netback Including Royalty Income	55.25	58.34	68.09	49.81	57.69
Natural Gas *($/Mcfe)*					
Price Received [1]	3.40	3.78	2.60	3.81	3.41
Royalties Paid	(0.05)	(0.08)	0.06	(0.07)	(0.04)
Production Costs	(0.84)	(0.80)	(0.81)	(0.75)	(0.80)
Transportation and Marketing	(0.23)	(0.26)	(0.28)	(0.27)	(0.25)
Netback	2.28	2.64	1.57	2.72	2.32
Royalty Income	-	-	-	-	-
Netback Including Royalty Income	2.28	2.64	1.57	2.72	2.32
NGL *($/bbl)*					
Price Received [1]	86.80	86.60	95.58	85.45	88.45
Royalties Paid	(16.75)	(16.10)	(12.59)	(9.59)	(13.16)
Production Costs	(5.17)	(5.03)	(5.02)	(4.74)	(4.98)
Transportation and Marketing	(1.47)	(1.66)	(1.71)	(1.63)	(1.61)
Netback	63.41	63.81	76.26	69.49	68.70
Royalty Income	0.09	0.08	0.06	0.04	0.06
Netback Including Royalty Income	63.50	63.89	76.32	69.53	68.76

(1) Does not include royalty income.

ADVISORIES

Non-GAAP Measures: *This Statement of Reserves Data and Other Oil and Gas Information uses "netback", which does not have a standardized meaning prescribed by GAAP and therefore may not be comparable to measures by other companies where similar terminology is used. Netback denotes petroleum and natural gas revenue less royalties, less operating expenses and less transportation and marketing expenses.*

Boe Conversions: *Barrels of oil equivalent ("**boe**") amounts have been calculated by using the conversion ratio of six thousand cubic feet (6 Mcf) of natural gas to one barrel of oil (1 bbl). Boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 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.*

Mcfe, MMcfe, Bcfe or Tcfe Conversions: *Thousands of cubic feet of gas equivalent ("**Mcfe**"), millions of cubic feet of gas equivalent ("**MMcfe**"), billions of cubic feet of gas equivalent ("**Bcfe**") and trillions of cubic feet of gas equivalent ("**Tcfe**") amounts have been calculated by using the conversion ratio of six thousand cubic feet (6 Mcf) of natural gas to one barrel of oil (1 bbl). Mcfe, MMcfe, Bcfe and Tcfe may be misleading, particularly if used in isolation. A Mcfe, MMcfe, Bcfe or Tcfe conversion ratio of 6 Mcf to 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.*

Forward-Looking Information: *This Statement of Reserves Data and Other Oil and Gas Information contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to future events or future performance and is based upon the Corporation's current internal expectations, estimates, projections, assumptions and beliefs. All information other than historical fact is forward-looking information. Information relating to "reserves" is forward-looking as it involves the implied assessment, based on certain estimates and assumptions, that the reserves exist in the quantities estimated and that they will be commercially viable to produce in the future. Words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "may", "will", "potential", "proposed" and other similar words that convey certain events or conditions "may" or "will" occur are intended to identify forward-looking information. In particular, this Statement of Reserves Data and Other Oil and Gas Information contains forward-looking information, including among other places, under the document headings "Net Present Value of Future Net Revenue", "Future Development Costs", "Properties With no Attributed Reserves", "Additional Information Regarding Abandonment and Reclamation Costs", "Tax Horizon" and "Production Estimates". This forward-looking information includes but is not limited to statements regarding: business strategy, plans and priorities; planned drilling, exploration and development; the quantity and development of oil and gas reserves; and other expectations, beliefs, plans, goals, objectives, assumptions, information and statements about possible future events, conditions, results of operations or performance.*

The forward-looking information is based upon assumptions as to future commodity prices, currency exchange rates, inflation rates, well production rates, well drainage areas, success rates for future drilling and availability of labour and services. With respect to estimates of reserves and resource volumes, a key assumption is the validity of the data used by Deloitte in their independent reserves evaluation and resource assessment. With respect to estimates of numbers of future wells to be drilled a key assumption is that geological and other technical interpretations performed by the Corporation's technical staff, which indicate that commercially economic reserves can be recovered from the Corporation's lands as a result of drilling such future wells, are valid.

Undue reliance should not be placed on forward-looking information, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. Although the Corporation believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. As a consequence, actual results may differ materially from those anticipated.

Forward-looking information necessarily involves both known and unknown risks associated with oil and gas exploration, production, transportation and marketing such as uncertainty of geological and technical data, imprecision of reserves and resources estimates, operational risks, environmental risks, loss of market demand, general economic conditions affecting ability to access sufficient capital, changes in governmental regulation of the oil and gas industry and competition from others for scarce resources.

The foregoing list of risk factors is not exhaustive. Additional information on these and other risk factors that could affect operations or financial results are included in the Corporation's most recent Annual Information Form, in the Report on Reserves Data by the Corporation's Independent Qualified Reserves Evaluator; and in the Report of Management and Directors on Oil and Gas Disclosure and in other reports filed with Canadian securities regulatory authorities. Forward-looking information is based on estimates and opinions of management at the time the information is presented. The Corporation is not under any duty to update the forward-looking information after the date of this Statement of Reserves Data and Other Oil and Gas Information to conform such information to actual results or to changes in the Corporation's plans or expectations, except as otherwise required by applicable securities laws.

DEFINITIONS

Definitions

In this Statement of Reserves Data and Other Oil and Gas Information, the capitalized terms set forth below have the following meanings. Certain terms used but not defined herein shall have the same meanings as in NI 51-101 and CSA Staff Notice 51-324.

"**2013 Reserves Evaluation**" means the independent evaluation dated February 5, 2014 prepared by Deloitte, evaluating the Corporation's oil and natural gas reserves at December 31, 2013.

"**Birchcliff**" or "**Corporation**" means Birchcliff Energy Ltd.

"**CSA Staff Notice 51-324**" means Canadian Securities Administrators Staff Notice 51-324 – *Glossary to NI 51-101*.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook.

"**Deloitte**" means Deloitte LLP, independent qualified reserves evaluators of Calgary, Alberta.

"**Deloitte Price Forecast**" means Deloitte's December 31, 2013 forecast price assumptions set out in Table 5 of this NI 51-101F1.

"**Gross**" means:

(a) in relation to the Corporation's interest in production or reserves, the Corporation's working interest (operating or non-operating) share before deduction of royalty obligations and without including any royalty interests;

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

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

"**Montney/Doig Natural Gas Resource Play**" means the Corporation's Montney and Doig formations natural gas resource play located northwest of Grand Prairie, Alberta.

"**Net**" means:

(a) in relation to the Corporation's interest in production or reserves, the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in such production or reserves;

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

(c) in relation to properties, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

"**NI 51-101**" means National Instrument 51 101 – *Standards of Disclosure for Oil and Gas Activities*.

"**NI 51-101F1**" means Form 51-101F1 – *Statement of Reserves Data and Other Oil and Gas Information*.

"**Reserves**" means estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the 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; and

(c) **Possible Reserves** are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

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

(a) **Developed Reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing; and

(b) **Undeveloped Reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

"**Uncertainty Ranges**" are described by the COGE Handbook as low, best, and high estimates for reserves and resources as follows:

(a) **Low Estimate** is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P_{90}) that the quantities actually recovered will equal or exceed the low estimate;

(b) **Best Estimate** is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P_{50}) that the quantities actually recovered will equal or exceed the best estimate; and

(c) **High Estimate** is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P_{10}) that the quantities actually recovered will equal or exceed the high estimate.

"**Working interest**" means a percentage of ownership in an oil and gas property, obligating the owner to share in the costs of exploration, development and operations and granting the owner the right to share in production revenue after royalties are paid.

"**Worsley Charlie Lake Light Oil Resource Play**" means the Corporation's Charlie Lake formation light oil resource play located near Worsley, Alberta.

ABBREVIATIONS, CONVERSIONS AND CONVENTIONS

Abbreviations

The abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

bbls	barrels
bbls/d	barrels per day
Mbbls	thousand barrels
MMbbls	million barrels
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
NGLs	natural gas liquids
LNG	liquefied natural gas

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Tcf	trillion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m^3	cubic metres
GJ	gigajoule

Other

AECO	benchmark natural gas price determined at the AECO 'C' hub in southeast Alberta
WTI	West Texas Intermediate crude oil, a benchmark oil price determined at Cushing, Oklahoma
$000	thousands of dollars
MM$	millions of dollars

Conversions

The following table sets forth certain Standard Imperial Units and International System of Units conversions.

From	To	Multiply By
Mcf	m^3	28.174
Mcf	GJ	1.055
m^3	cubic feet	35.494
bbls	cubic metres	0.159
acres	hectares	0.405
sections	acres	640
sections	hectares	256

Conventions

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.