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BLACKBIRD ENERGY INC.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

EFFECTIVE JULY 31, 2015

DATED NOVEMBER 18, 2015

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ABBREVIATIONS AND CONVERSION

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

Crude Oil and Natural Gas Liquids

bbl	Barrel
Mbbl	thousand barrels
bbls/d	barrels per day
BOE or boe	barrels of oil equivalent of crude oil, natural gas liquids, and natural gas on the basis of 1 bbl for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either actual energy content or current prices)
Mboe	thousand barrels of oil equivalent
boe/d	barrels of oil equivalent per day
NGL	natural gas liquids
2D	two dimensional seismic
psi	pounds per square inch

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
Bcf	billion cubic feet
MMcf/d	million cubic feet per day
bbls/MMcf	barrels per million cubic feet
m^3	metres cubed
kPa	kilopascal
M$	thousands of dollars
MMBtu	million British Thermal Units
3D	three dimensional seismic

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To convert from	To	Multiply by
Mcf	1,000 cubic metres of gas	0.028
1,000 cubic metres of gas	Mcf	35.493
bbl	cubic metres of oil	0.158
cubic metres of oil	bbl	6.290
Feet	metres	0.305
Metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
GJ	MMBtu	0.950

NOTES AND DEFINITIONS

AECO	a natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° 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
M$	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

"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: (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) 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.

"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 (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. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide 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 recorded from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"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 + probable reserves. The following terms, used in the preparation of the GLJ Report (as defined herein) and this document have the following meanings:

"Associated gas" means the gas cap overlying a crude oil accumulation in a reservoir.

"**Corporation"** or **"Blackbird"** means Blackbird Energy Inc., including all of its subsidiaries, unless the context otherwise requires.

"Crude oil" or **"Oil"** means a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of Sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas.

"Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"Development well" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

“Exploration costs” means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as “prospecting costs”) and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);
(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;
(c) dry hole contributions and bottom hole contributions;
(d) costs of drilling and equipping exploratory wells; and
(e) costs of drilling exploratory type stratigraphic test wells.

“Exploratory well” means a well that is not a development well, a service well or a stratigraphic test well.

“Field” means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to denote localized geological features, in contrast to broader terms such as “basin”, “trend”, “province”, “play” or “area of interest”.

“Forecast prices and costs” means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;
(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

“Future income tax expenses” means future income tax expenses estimated (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

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

“Future net revenue” a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs.

“Gross” means:

(a) in relation to the Corporation’s interest in production or reserves, its “Corporation gross reserves”, which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;
(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 of properties in which the Corporation has an interest.

“Natural gas” means a naturally occurring mixture of hydrocarbon gases and other gases.

“Natural gas liquids” means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

“Net” means:

(a) in relation to the Corporation’s interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;
(b) in relation to the Corporation’s interest in wells, the number of wells obtained by aggregating the Corporation’s working interest in each of its gross wells; and
(c) in relation to the Corporation’s interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

“Non-associated gas” means an accumulation of natural gas in a reservoir where there is no crude oil.

“Operating costs” or “production costs” means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

“Production” means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

“Property” includes:

(a) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;
(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and
(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as “producer” of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"Property acquisition costs" means costs incurred to acquire a property (directly by purchase or lease or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;
(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;
(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"Proved property" means a property or part of a property to which reserves have been specifically attributed.

"Reservoir" means a subsurface rock unit that contains an accumulation of petroleum.

"Service well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

"Solution gas" means gas dissolved in crude oil.

"Stratigraphic test well" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) exploratory type" if not drilled into a proved property; or (b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"Support equipment and facilities" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"Unproved property" means a property or part of a property to which no reserves have been specifically attributed.

"Well abandonment costs" means costs of abandoning well and surface lease reclamation. They do not include costs of abandoning the gathering system, suspended wells, batteries, plants, or processing facilities.

Note Regarding Nomenclature:

Throughout this report "Corporation Interest" reserves refers to the sum of royalty interest* and working interest reserves before deduction of royalty burdens payable. "Working Interest" reserves equate to those reserves that are referred to as "Corporation Gross" reserves by the Canadian Securities Administrators in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). In this document, Corporation Gross (or working interest) volumes are presented in tables to correspond to NI 51-101 disclosure requirements.

**Royalty interest reserves include royalty volumes derived only from other working interest owners.*

FORWARD LOOKING STATEMENTS

This Form 51-101 F1 report (this "report") contains certain information and statements which constitute forward-looking information and forward-looking statements within the meaning of applicable Canadian securities laws (collectively, the "forward-looking statements"). Forward-looking statements are statements that do not relate strictly to historical or current facts, and words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "believe" and "intend", or similar expressions, will generally constitute forward-looking statements. Forward-looking statements represent management's reasonable projections, expectations, and estimates as of the date of this document, but undue reliance should not be placed upon it as it is derived from numerous assumptions. These assumptions are subject to known and unknown risks and uncertainties which may cause actual performance and financial results to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. In particular, this report contains forward-looking statements pertaining to the following: the characteristics of the Corporation's oil and natural gas properties; the Corporation's strategy for growth; future exploration and development activities; the Corporation's tax horizon; commodity prices and exchange rates; treatment under governmental and other regulatory regimes and tax, environmental and other laws; and expectations regarding the source of funds for future development costs. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future. The forward-looking statements in this report are subject to significant risks and uncertainties and is based on a number of material factors and assumptions which may prove to be incorrect, including but not limited to the following: assuming normal seasonal weather conditions; that the drilling and related equipment necessary for the Corporation's planned operations will be available on terms that are favourable to the Corporation and within the times planned by the Corporation; that skilled labour will be available on terms that are favourable to the Corporation; that the Corporation will be able to obtain additional financing on satisfactory terms; and that the Corporation will be able to attract and retain qualified personnel.

While management of the Corporation anticipates that subsequent events and developments may cause management's views to change, management does not have an intention to update the forward-looking statements contained herein, except as required by applicable securities laws. The forward-looking statements contained herein represent management's views as of the date of this report and such information should not be relied upon as representing the Corporation's views as of any date subsequent to the date of this report. Blackbird has attempted to identify important factors that could cause actual results, performance or achievements to vary from those current expectations or estimates expressed or implied by the forward-looking statements. However, there may be other factors that cause results, performance or achievements not to be as expected or estimated and that could cause actual results, performance or achievements to differ materially from current expectations. Other risks and uncertainties include, but are not limited to, the following: normal risks common to the oil and gas industry, including various operational risks in the carrying out of exploration, development and production operations; volatility of commodity prices; health, safety and environmental risks; development and exploitation projects; uncertainty of estimates and projections of production, costs and expenses; risks as to the availability and pricing of appropriate financing alternatives on acceptable terms; potential changes in income tax regulations, governmental policies, rules, practices or approval process changes, or delays, or enhancements; delays resulting from adverse weather conditions; delays resulting from an inability to obtain and/or maintain required regulatory approvals and licenses and the ability to access sufficient debt or equity capital from internal and external sources; the Corporation's ability to attract and retain qualified personnel; general economic conditions in Canada and globally; competition for, among other things, capital and acquisitions of reserves and undeveloped lands; risks and uncertainty relating to the accuracy of oil and gas reserve estimates and evaluations and estimated production levels as they are affected by the Corporation's exploration and development drilling and estimated decline rates; adverse regulatory rulings, orders and decisions; stock market volatility and market valuations; and the risk factors set forth in the Annual Information Form of the Corporation for the year ended July 31, 2015 available on SEDAR at www.sedar.com.

The forward-looking information contained in this report is given as of the date hereof and, accordingly, is subject to change after such date. The Corporation does not undertake to update or revise any forward-looking information, except as, and to the extent, required by applicable securities laws.

The forward-looking information contained in this report is expressly qualified by this cautionary statement.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

In accordance with NI 51-101, the Corporation engaged GLJ Petroleum Consultants Ltd. ("GLJ" or the "Evaluator") to prepare a report (the "GLJ Report") dated September 17, 2015. The GLJ Report, as at the **effective date of July 31, 2015**, evaluated all the oil, NGL and natural gas reserves at the Elmworth property held by the Corporation. All other reserves have either been sold or the Corporation does not attribute any value to the properties.

The tables below are a summary of the oil, NGL and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the GLJ Report based on forecast price and cost assumptions. 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 GLJ. Readers are cautioned that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by GLJ does not 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, NGL 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.

The GLJ Report is based on certain factual data supplied by the Corporation and the Evaluator'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 the Evaluator and accepted without any further investigation. The Evaluator accepted this data as presented and neither title searches nor field inspections were conducted.

All evaluated properties are located onshore in the province of Alberta, Canada.

All monetary values are expressed in Canadian Currency unless stated otherwise.

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PART 1 DATE OF STATEMENT

Item 1.1 RELEVANT DATES

Effective Date

The effective date of the reserves estimates and revenue projections in this report is July 31, 2015.

Preparation Date

The preparation date (the latest date of receipt of information relevant to this evaluation by GLJ) of this report was September 17, 2015.

PART 2 DISCLOSURE OF RESERVES DATA

Item 2.1 SUMMARY OF OIL AND GAS RESERVES

FORECAST PRICES AND COSTS - Effective July 31, 2015

	SUMMARY OF CORPORATION OIL AND GAS RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVE CATEGORY	Gross Mbbl	Net Mbbl	Gross Mbbl	Net Mbbl	Gross MMcf	Net MMcf	Gross Mbbl	Net Mbbl	Gross Mboe	Net Mboe
Developed Producing	0	0	0	0	0	0	0	0	0	0
Developed Non-Producing	223	176	0	0	2,352	2,157	117	90	732	625
Undeveloped	0	0	0	0	0	0	0	0	0	0
TOTAL PROVED	**223**	**176**	**0**	**0**	**2,352**	**2,157**	**117**	**90**	**732**	**625**
Probable	97	65	0	0	988	893	49	35	311	249
TOTAL PROVED + PROBABLE	**320**	**241**	**0**	**0**	**3,340**	**3,050**	**166**	**125**	**1,043**	**874**

Item 2.2 SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE

FORECAST PRICES AND COSTS (Effective July 31, 2015)

	NET PRESENT VALUES OF FUTURE NET REVENUE										
	BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR)					UNIT VALUE 10% DISCOUNT(1)	AFTER INCOME TAXES DISCOUNTED AT (%/YEAR)				
RESERVE CATEGORY	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	$/BOE	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Developed Producing	0	0	0	0	0	0	0	0	0	0	0
Developed Non-Producing	20,654	16,152	13,323	11,397	9,998	21.30	18,796	15,007	12,575	10,883	9,632
Undeveloped	0	0	0	0	0	0	0	0	0	0	0
TOTAL PROVED	20,654	16,152	13,323	11,397	9,998	21.30	18,796	15,007	12,575	10,883	9,632
Probable	9,875	5,940	4,214	3,315	2,773	16.94	7,439	4,516	3,253	2,605	2,219
TOTAL PROVED + PROBABLE	30,529	22,092	17,537	14,712	12,771	20.06	26,235	19,523	15,828	13,488	11,851

NOTE:

(1) Unit values are based on Corporation Net Reserves.

Item 2.3 TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

FORECAST PRICES AND COSTS (Effective July 31, 2015)

RESERVE CATEGORY	REVENUE (M$)	ROYALTY (M$)	OP. COSTS (M$)	DEV. COSTS (M$)	WELL ABAND. COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Developed Producing	0	0	0	0	0	0	0	0
Developed Non-Prod.	38,495	6,752	10,069	1,020	0	20,654	1,858	18,796
Undeveloped	0	0	0	0	0	0	0	0
TOTAL PROVED	38,495	6,752	10,069	1,020	0	20,654	1,858	18,796
Probable	20,272	5,178	5,220	0	0	9,875	2,436	7,439
TOTAL PROVED + PROBABLE	58,767	11,930	15,289	1,020	0	30,529	4,294	26,235

Item 2.4 FUTURE NET REVENUE BY PRODUCTION GROUP

FORECAST PRICES AND COSTS (Effective July 31, 2015)

RESERVE CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE[1]	
			$/boe	$/Mcfe
Proved Producing	Conventional Natural gas	0	0	0
Total Proved Producing	-	0	0	0
Proved	Conventional Natural gas	13,323	21.30	3.55
Total Proved	-	13,323	21.30	3.55
Proved Plus Probable	Conventional Natural gas	17,538	20.06	3.34
Total Proved Plus Probable	-	17,538	20.06	3.34

NOTE:

[1] *Unit values are based on Corporation Net Reserves.*

PART 3 PRICING ASSUMPTIONS OF FORECASTED PRICES USED IN ESTIMATES

The following price forecasts effective July 1, 2015 were used by the Evaluator:

		Edmonton Light, Sweet Oil	Hardisty Heavy Oil	NGL C5+ Stream Quality	AECO Spot Natural Gas
Year	Inflation %	CAD/bbl	CAD/bbl	CAD/bbl	CAD/MMBtu
2015 Q3-Q4	2.0	71.56	55.24	73.03	3.13
2016	2.0	75.76	58.39	81.06	3.30
2017	2.0	76.47	58.95	81.82	3.50
2018	2.0	82.35	64.64	88.12	3.79
2019	2.0	88.24	69.32	94.41	3.99
2020	2.0	94.12	74.01	100.71	4.20
2021	2.0	100.00	78.70	107.00	4.40
2022+	2.0	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.

The Corporation's average prices received for the fiscal year August 1, 2014 to July 31, 2015 were:

Heavy Oil: $50.71 /bbl
Natural Gas: $ 4.03/mcf
NGLs: $76.20 /bbl

PART 4 RECONCILIATION OF GROSS RESERVES BY PRODUCT TYPE

The following table sets forth the changes between the Corporation's total proved, probable and total proved plus probable gross reserves as at July 31, 2015 and July 31, 2014. The Corporation has no reserves of heavy oil or coal bed methane. All light oil, medium oil, natural gas liquids and natural gas are attributed to the Elmworth Montney property, located in Alberta, near Grande Prairie. The following is based on forecast price and cost assumptions.

	LIGHT AND MEDIUM OIL			HEAVY OIL			NATURAL GAS LIQUIDS		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)
July 31, 2014	0	0	0	14	5	19	151	613	764
Discoveries	0	0	0	0	0	0	0	0	0
Extensions	223	97	321	0	0	0	117	49	166
Infill Drilling	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	5	(1)	4	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	(9)	(4)	(13)	(151)	(613)	(764)
Economic Factors	0	0	0	0	0	0	0	0	0
Production	0	0	0	(10)	0	(10)	0	0	0
July 31, 2015	**223**	**97**	**321**	**0**	**0**	**0**	**117**	**49**	**166**

	CONVENTIONAL NATURAL GAS			COAL BED METHANE			BOE		
FACTORS	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved + Probable (MMcf)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved + Probable (MMcf)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved + Probable (Mboe)
July 31, 2014	1,865	7,331	9,196	0	0	0	476	1,840	2,316
Discoveries	0	0	0	0	0	0	0	0	0
Extensions	2,352	988	3,340	0	0	0	732	311	1,043
Infill Drilling	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0
Technical Revisions	(13)	0	(13)	0	0	0	3	(1)	2
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	(1,844)	(7,331)	(9,175)	0	0	0	(467)	(1,838)	(2,305)
Economic Factors	0	0	0	0	0	0	0	0	0
Production	(8)	0	(8)	0	0	0	(12)	0	(12)
July 31, 2015	**2,352**	**988**	**3,340**	**0**	**0**	**0**	**732**	**312**	**1,044**

Extensions to the light oil, medium oil, natural gas liquids and conventional natural gas categories were a result of the Corporation completing and testing its first two 100% working interest Elmworth Montney wells, which are located at 06-26-70-07-W6 ("06-26") and 05-26-70-07W6 ("05-26"). These wells were shut-in after testing. Reserves have been estimated by the Evaluator based on available test data and forecasts.

The Corporation sold its Bigstone property in September 2014 for cash consideration of $8.8 million, which resulted in significant dispositions in the natural gas liquids and conventional natural gas reserve categories.

Due to commodity pricing and poor economics, the Corporation shut-in operated properties during the year which were subsequently sold in June 2015 for cash consideration of $50 thousand, including its Flaxcombe, Dankin and Alsask (located to the west of the 3rd meridian) properties. This resulted in further reserves dispositions. The Corporation has working interests remaining in its Ferrier, Pembina, Watts, Badger and Alsask (located to the west of the 4th meridian) properties, which have had their attributed reserves adjusted downward to nil.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 UNDEVELOPED RESERVES

The following table provides a summary of the undeveloped reserves first attributed during the prescribed fiscal year and the Corporation total at the current year-end effective date.

	CORPORATION GROSS UNDEVELOPED RESERVES FIRST ATTRIBUTED BY YEAR									
	LIGHT AND MEDIUM OIL(Mbbl)		HEAVY OIL (Mbbl)		NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbl)		BOE (Mboe)	
	*First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
	Proved Undeveloped									
Prior	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	749	749	24	24	149	149
2013	-	-	-	-	417	417	20	20	90	90
2014	-	-	-	-	815	1,653	68	139	204	414
2015	-	-	-	-	-	-	-	-	-	-
	Probable Undeveloped									
Prior	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	1,123	1,123	37	37	224	224
2013	-	-	-	-	1,916	2,915	93	141	412	627
2014	-	-	-	-	3,608	7,210	303	605	904	1,807
2015	-	-	-	-	-	-	-	-	-	-

* "First Attributed" refers to reserves first attributed at year–end of corresponding fiscal year.

The proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the "Canadian Oil and Gas Evaluation Handbook" maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time. All gross proved and probable undeveloped reserves reported above were sold by the Corporation during the year ended July 31, 2015.

Item 5.2 SIGNIFICANT FACTORS OR UNCERTAINTIES

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 an independent reserves evaluator, being GLJ.

As circumstances change and additional data becomes 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.

The evaluated oil and gas properties of the Corporation have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing corporation.

Corporate reserves at July 31, 2015 consist of Elmworth light oil, medium oil, natural gas liquids and natural gas reserves in Alberta, near Grande Prairie.

Readers are also referred to the Corporation's financial statements and management's discussion and analysis for the year ended July 31, 2015 for more information regarding sales.

Item 5.3 FUTURE DEVELOPMENT COSTS

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves (using forecast prices and costs).

M$								
RESERVE CATEGORY	2015	2016	2017	2018-2026	Sub Total	Remainder	Total	10% Discounted
Proved Developed Non-Producing	0	1,020	0	0	1,020	0	1,020	935
Total Proved	0	1,020	0	0	1,020	0	1,020	935
Total Proved+ Probable	0	1,020	0	0	1,020	0	1,020	935

Sources of Funding

All future development costs relate to the Elmworth property. It is expected that these will be financed through internally generated cash flows.

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.1 OIL AND GAS PROPERTIES AND WELLS

The Corporation's properties, plants, facilities and installations are located exclusively in Western Canada and more specifically in the Provinces of Alberta and Saskatchewan and are located onshore.

Elmworth Project

As at July 31, 2015, Blackbird's core project, the Elmworth Project, consisted of 78.0 net sections (49,920 net acres), the majority of which are contiguous. Blackbird holds a 100% working interest in the Elmworth Project. The Corporation believes the exploration risk of the Elmworth Project to have been significantly reduced through the drilling in the vicinity by industry majors. Currently and going forward, Blackbird expects the Elmworth Project to be its predominant focus.

On March 4, 2015 Blackbird announced that its first two 100% working interest Elmworth Montney wells, the 06-26 and 05-26, were successfully completed and tested.

The 06-26 well, which targeted the Middle Montney interval, was drilled to a total measured depth of 4,734 meters, including a horizontal lateral of 2,052 meters. The well was stimulated with a 14 stage slick-water plug-and-perf completion with three to five perforations per stage, for a total of 51 intervals, and approximately 55 tonnes of proppant per interval. A total of 15,500m3 (approximately 97,500 barrels) of slick-water was pumped down-hole.

The 06-26 well flowed on cleanup, recovering approximately 21.7% of its load fluid prior to being shut-in, to allow for the reservoir to imbibile load fluids and to gather further pressure data, as is the industry practice.

The 05-26 well, which targeted the Upper Montney interval, was drilled to a total measured depth of 4,621 meters including a horizontal lateral of 1,951 meters. The well was stimulated with a 13 stage slick-water plug-and-perf completion, which included three to five perforations per stage, for a total of 49 intervals, and approximately 55 tonnes of proppant per interval. A total of 13,800m3 (approximately 86,800 barrels) of slick-water was pumped down-hole. The 05-26 well flowed on cleanup, recovering approximately 32.3% of its load fluid.

During the test, the well returned approximately 1,077 bbls/d of load fluid. The well was shut-in to allow for the reservoir to imbibe load fluids and to gather further pressure data, as is the industry practice.

The Company plans to further test both of these wells in the future. A summary of the existing 06-26 and 05-26 test results are as follows:

Well	**Flowing Pressure[1] (kPa)**	**Raw Gas (MMcf/d)**	**Liquid Hydrocarbons[2] (bbls/d)**	**Total Combined Production (boe/d)**	**Liquids/Gas Ratio[2] (bbls/MMcf)**
05-26	2,100	0.9	313	466	341
06-26 (Restricted) [3]	19,400 (Bottom-Hole)	1.36	181	407	133

Notes:

1) Bottom hole pressure of 6-26 is due to the 15/64 inch down-hole choke discussed previously.
2) Liquid Hydrocarbons includes free condensate plus estimated NGL recovery (35 bbls/MMcf).
3) Restricted through 15/64 inch downhole choke. Independent third party analysis of test and pressure data estimates that well is capable of between 3.0 MMcf/d and 3.5 MMcf/d plus associated liquids.

East Wapiti Project

The Corporation's Wapiti Project consists of 77.0 net sections (49,280 net acres) of land in a Montney resource prospective corridor north east of Blackbird's Elmworth project. Blackbird holds a 100% working interest in the lands. Blackbird has only begun its initial geological review but has begun to identify prospective targets.

Alsask Project

The Alsask Project consists of 1.0 net section (640 net acres) of land located near the Alberta/Saskatchewan border. The Corporation sold its one non-producing well and land in Saskatchewan. The remaining Alsask wells and land is located in Alberta and was shut-in by the Corporation during the year. The property also has a water disposal well. Blackbird holds a 100% working interest in the project.

The number of producing and non-producing wells is shown below:

	OIL WELLS				GAS WELLS			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Saskatchewan, Canada	0	0	1	1	0	0	0	0
Alberta, Canada	0	0	5	4.24	2	0.77	6	5.50
TOTAL	**0**	**0**	**6**	**5.24**	**2**	**0.77**	**6**	**5.50**

Item 6.2 PROPERTIES WITH NO ATTRIBUTED RESERVES

The Corporation considers its Ferrier, Pembina, Watts, Badger and Alsask (located to the west of the 4th meridian) properties, each of which is located in Canada, to be non-core as the Corporation is currently focused on exploring and developing its core Montney lands at Elmworth and East Wapiti, Alberta. These non-core properties no longer have any attributed reserves.

The table above in Item 6.1 includes non-core wells for which no reserves have been attributed.

East Wapiti

The Corporation's Wapiti Project consists of 77.0 net sections (49,280 net acres) of land in a Montney resource prospective corridor northeast of Blackbird's Elmworth project. Blackbird has only begun its initial geological review but has begun to identify prospective targets.

Expiries

Of the 78.0 net sections of Elmworth Montney land held at July 31, 2015, there are 11.0 net sections which have current expiry dates occurring within the next fiscal year. The remaining 67.0 net sections have expiry dates ranging from 2017 to 2020. Blackbird does not expect any of its rights to explore, develop, or exploit any unproved property to expire within one year, other than these noted.

Work Commitments

There are currently no work commitments associated with any unproved property.

Item 6.2.1 SIGNIFICANT FACTORS OR UNCERTAINTIES RELEVANT TO PROPERTIES WITH NO ATTRIBUTED RESERVES

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases and fires and spills.

The Corporation's properties with no attributed reserves have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing Corporation.

Item 6.3 FORWARD CONTRACTS

The Corporation did not hold any forward contract obligations and accordingly financial hedges have not been included in the economic forecasts.

Item 6.4 ADDITIONAL INFORMATION ON ABANDONMENT & RECLAMATION COSTS

The Corporation's future abandonment and reclamation costs as estimated in the decommissioning liability in its financial statements as at and for the year ending July 31, 2015 include costs for the existing wells (whether reserves attributed or not), pipelines and production facilities. Based on its working interest, the Corporation estimates the current abandonment and reclamation costs for each well, which includes a provision for the related facilities and pipelines. Those current costs are adjusted to the future expected retirement date using an inflation rate of 1.5% and an estimate of a retirement date being the latest production year determined by the independent reserve evaluator for the field.

The Corporation's total future undiscounted decommissioning liability is estimated to be $1.1 million. When discounted at 10% the amount is $0.3 million. No abandonment and reclamation costs have been included in forecasts prepared by the Evaluator. The difference between the Corporation's estimated liability and that of GLJ is that the Corporation provides for all wells, lease sites, pipelines and facilities while the Evaluator provides only for certain locations.

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

Blackbird's working interest share of costs, net of salvage value, will be funded through cash flow from operations.

Item 6.5 TAX HORIZON

Based on after tax economic forecasts prepared by GLJ, income taxes are payable by the Corporation in 2019 in the Total Proved reserves category and 2018 in the Total Proved plus Probable reserves category. After tax revenue projections are provided in the After Tax Analysis section of the report (Item 2.2).

Item 6.6 COSTS INCURRED

The following table summarizes the capital expenditures made by Blackbird on oil and natural gas properties for the period ended July 31, 2015:

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
	(M$)	(M$)	(M$)	(M$)
Elmworth	-	6.0	22.5	-
Wapiti	-	0.5	-	-
Alberta & Saskatchewan	-	-	-	0.6

Item 6.7 EXPLORATION AND DEVELOPMENT ACTIVITIES

The Corporation incurred $21.6 million of drilling, completing, and testing costs on the 100% working interest 06-26 and 05-26 Elmworth Montney wells during the year ended July 31, 2015. These wells were deemed exploratory gas wells. The Corporation also incurred seismic, surveying, and engineering costs in Elmworth. Development costs incurred during the year ended July 31, 2015, in Alberta and Saskatchewan related primarily to drilling, completion, recompletion, and workover.

On October 27, 2015, Blackbird successfully drilled, logged, and cased its third 100% working interest well at Elmworth, located at 2-20-70-7W6 (“2-20”). This location was selected based on extensive geological research, competitor data, and proximity to planned infrastructure.

The 2-20 well drill program included the drilling of a vertical pilot well from surface location 10-8-70-7W6 to a vertical depth of 2,582 meters. The vertical pilot well was then logged from surface to the bottom of the lower Montney. Upon completion of logging operations, Blackbird drilled a horizontal leg of approximately 2,000 meters targeting the middle Montney formation to downhole location 2-20-70-7W6. The measured depth of the 2-20 well is 4,660 meters.

The 2-20 well was spud on September 24, 2015 and drilling operations were completed in 32 days from spud to rig release, including 8 days to drill and log the vertical pilot well. This represented a significant improvement in drilling efficiency and planned capital expenditure compared to Blackbird's previous wells.

Blackbird is planning to complete the 2-20 well using NCS sliding sleeve frac technology run on coiled tubing. The completion will consist of 71 individual foam fracs over the horizontal length of approximately 2,000 meters. Subsequent to completion operations, the 2-20 well will be production tested. The Company expects to announce results from the 2-20 production test in January 2016.

Item 6.8 PRODUCTION ESTIMATES

There is no production estimated by the Evaluator for the First Year Production in the estimates of future net revenue from the forecast case of the various reserves classes disclosed above under Item 2.1.

Item 6.9 PRODUCTION HISTORY

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

	July 31, 2015 Year End			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Production				
Heavy oil (bbls/d)	44.24	32.26	11.64	24.04
Natural gas (Mcf/d)	80.58	77.01	2.33	4.55
Natural gas liquids (bbls/d)	2.33	1.06	0.04	0.17
Total production (BOE/d)	60.00	46.16	12.07	24.97
Revenue				
Heavy oil ($/bbl)	72.03	38.08	31.57	37.40
Natural Gas ($/Mcf)	3.77	4.29	4.34	3.68
Natural gas liquids ($/bbl)	82.00	62.67	40.23	62.98
Total revenue ($/BOE)	61.35	35.22	31.79	37.71
Royalties ($/BOE)	4.01	3.35	5.15	10.78
Production Costs ($/BOE)	47.25	52.75	148.86	24.31
Netbacks ($/BOE)	10.09	(20.88)	(122.22)	2.62

Production Volume by Product

The following table discloses in total, working interest production volumes for the year ended July 31, 2015 for each product type:

	Heavy oil	**Natural gas**	**NGLs**	**Total**
	bbls	**Mcf**	**bbls**	**BOE**
TOTAL	10,286	13,872	299	12,897

The following fields accounted for 20% or more of the total working interest production volumes for the year ended July 31, 2015 by product type:

	Heavy oil	**Natural gas**	**NGLs**
	bbls	**Mcf**	**bbls**
Ferrier	N/A	6,550	75
Watts	N/A	6,123	N/A
Flaxcombe	7,595	N/A	157