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BLACKBIRD ENERGY INC.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

EFFECTIVE JULY 31, 2016

DATED OCTOBER 21, 2016

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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, 2016 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 October 6, 2016. The GLJ Report, as at the **effective date of July 31, 2016**, evaluated all of 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, 2016.

Preparation Date

The preparation date (the latest date of receipt of information relevant to this evaluation by GLJ) of this report was September 19, 2016.

PART 2 DISCLOSURE OF RESERVES DATA

Item 2.1 RESERVES DATA (FORECAST PRICES AND COSTS)

1. Breakdown of Reserves (Forecast Case)

FORECAST PRICES AND COSTS (Effective July 31, 2016)

	SUMMARY OF CORPORATION OIL AND GAS RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		SHALE 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
Producing	0	0	0	0	0	0	0	0	0	0
Developed Non-Producing	0	0	0	0	5,344	4,908	599	459	1,489	1,277
Undeveloped	0	0	0	0	5,950	5,537	533	423	1,525	1,346
TOTAL PROVED	**0**	**0**	**0**	**0**	**11,294**	**10,445**	**1,132**	**882**	**3,014**	**2,623**
Probable	0	0	0	0	13,314	12,212	1,242	907	3,461	2,942
TOTAL PROVED + PROBABLE	**0**	**0**	**0**	**0**	**24,609**	**22,657**	**2,374**	**1,789**	**6,475**	**5,565**

2. Net Present Value of Future Net Revenue (Forecast Case)

FORECAST PRICES AND COSTS (Effective July 31, 2016)

	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$)	20 (M$)
Producing	0	0	0	0	0	0.00	0	0	0	0	0
Developed Non-Producing	22,514	16,504	12,550	9,810	7,815	9.83	22,514	16,504	12,550	9,810	7,815
Undeveloped	12,840	5,773	1,463	(1,325)	(3,224)	1.09	12,840	5,773	1,463	(1,325)	(3,224)
TOTAL PROVED	35,354	22,277	14,014	8,484	4,591	5.34	35,354	22,277	14,014	8,484	4,591
Probable	68,540	40,954	27,261	19,577	14,815	9.27	51,499	32,040	22,116	16,380	12,716
TOTAL PROVED + PROBABLE	103,893	63,231	41,275	28,061	19,406	7.42	86,853	54,317	36,129	24,864	17,307

NOTE:

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

3. Additional Information Concerning Future Net Revenue (Forecast Case)

Undiscounted Revenue and Costs

FORECAST PRICES AND COSTS (Effective July 31, 2016)

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$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Producing	0	0	0	0	0	0	-	-
Developed Non-Prod.	62,152	9,194	19,187	10,625	632	22,514	-	22,514
Undeveloped	61,031	8,133	19,636	19,960	462	12,840	-	12,840
TOTAL PROVED	123,182	17,327	38,823	30,585	1,094	35,354	-	35,354
Probable	159,014	27,665	48,558	13,525	725	68,540	17,041	51,499
TOTAL PROVED + PROBABLE	282,196	44,992	87,381	44,110	1,819	103,893	17,041	86,853

Discounted Future Net Revenue by Product Type

FORECAST PRICES AND COSTS (Effective July 31, 2016)

RESERVE CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE(1)	
			$/boe	$/Mcfe
Proved Producing	Shale Gas	0	0	0
Total Proved Producing	-	0	0	0
Proved	Shale Gas	14,014	5.34	0.89
Total Proved	-	14,014	5.34	0.89
Proved Plus Probable	Shale Gas	41,275	7.42	1.24
Total Proved Plus Probable	-	41,275	7.42	1.24

NOTE:

(1) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company Net Reserves.

PART 3 PRICING ASSUMPTIONS

Item 3.2 FORECAST PRICES USED IN ESTIMATES

The following price forecasts effective July 1, 2016 were used by the Evaluator:

		CADUSD Exchange Rate	NYMEX Henry Hub Constant 2016 $	NYMEX Henry Hub Then Current	Edmonton Propane	Edmonton Butane	Edmonton C5+ Stream Quality
Year	Inflation %	USD/CAD	USD/MMBtu	USD/MMBtu	CAD/bbl	CAD/bbl	CAD/bbl
2016 Q3-Q4	2.0	0.750	3.00	3.00	14.25	39.62	67.77
2017	2.0	0.775	3.14	3.20	16.61	46.52	71.10
2018	2.0	0.800	3.08	3.20	20.25	50.63	72.23
2019	2.0	0.825	3.20	3.40	24.61	52.73	75.22
2020	2.0	0.850	3.33	3.60	25.53	54.71	78.05
2021	2.0	0.850	3.44	3.80	27.18	58.24	83.08
2022	2.0	0.850	3.55	4.00	28.82	61.76	88.12
2023	2.0	0.850	3.66	4.20	30.47	65.29	93.15
2024	2.0	0.850	3.75	4.39	32.12	68.82	98.19
2025	2.0	0.850	3.75	4.48	32.97	70.65	100.79
2026+	2.0	0.850	3.75	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.

The Corporation's average prices received for the fiscal year August 1, 2015 to July 31, 2016 were:

Oil: $42.60 /bbl
Natural Gas: $ 2.20 /mcf
NGLs: $33.52 /bbl

PART 4 RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 RESERVES RECONCILIATION

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, 2016 and July 31, 2015. All natural gas and natural gas liquids 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 CRUDE			NATURAL GAS LIQUIDS		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)
July 31, 2015	223	97	321	117	49	166
Discoveries	0	0	0	0	0	0
Extensions	0	0	0	800	1,100	1,901
Infill Drilling	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0
Technical Revisions	(223)	(97)	(321)	215	92	308
Acquisitions	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0
Production	0	0	0	0	0	0
July 31, 2016	**0**	**0**	**0**	**1,132**	**1,242**	**2,374**
	NATURAL GAS			**BOE**		
FACTORS	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved + Probable (MMcf)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved + Probable (Mboe)
July 31, 2015	2,352	988	3,340	732	311	1,043
Discoveries	0	0	0	0	0	0
Extensions	8,925	12,321	21,246	2,288	3,154	5,442
Infill Drilling	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0
Technical Revisions	17	5	22	(5)	(4)	(9)
Acquisitions	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0
Production	0	0	0	0	0	0
July 31, 2016	**11,294**	**13,314**	**24,609**	**3,014**	**3,461**	**6,475**

Extensions to the natural gas and natural gas liquids categories were a result of the Corporation drilling, completing and testing its third 100% working interest Elmworth Montney well, which is located at 02-20-70-7W6 ("02-20 well"). The 02-20 well was shut-in after testing. Reserves have been estimated by the Evaluator based on available test data and forecasts.

The Corporation has working interests remaining in its Ferrier, Pembina, Watts, Badger and Alsask (located to the west of the 4th meridian) properties. These properties are considered to be non-core and have not been evaluated. Management does not attribute any reserves to these properties as they are immaterial to operations and the Corporation has no intention of further development in any of these areas.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 UNDEVELOPED RESERVES

Year First Attributed

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)		SHALE GAS (MMcf)		CONVENTIONAL 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	-	-	-	-	-	-	-	-	-	-
2016	-	-	5,950	5,950	-	-	533	533	1,525	1,525
	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	-	-	-	-	-	-	-	-	-	-
2016	-	-	11,046	11,046	-	-	986	986	2,827	2,827

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

General Basis for Reserves and Timing of Development

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 during the year ended July 31, 2016 are attributed to the Elmworth property.

Approximately 100 percent of the proved undeveloped reserves and 100 percent of the proved plus probable reserves are scheduled to be developed within the next three years.

Item 5.2 SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The Corporation's reserves are evaluated by 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, 2016 consist of Elmworth gas and natural gas liquids 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, 2016 for more information regarding sales.

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, 2016 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.

The Corporation's total future undiscounted decommissioning liability is estimated to be $1.5 million ($0.4 million discounted at 10%). The Evaluator has provided for abandonment costs of $95.0 thousand per well and reclamation costs of $35.0 thousand per well in their forecast. These costs are expressed in terms of 2016 Canadian dollars. The Evaluator's total future undiscounted abandonment and reclamation costs are $1.1 million ($0.1 million discounted at 10%) for the total Proved reserves category. The Evaluator's total future undiscounted abandonment and reclamation costs are $1.8 million ($0.1 million discounted at 10%) for the total Proved plus Probable reserves category. 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 (i.e. existing and future Elmworth Montney wells).

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 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	2016	2017	2018	2019-2027	Sub Total	Remainder	Total	10% Discounted
Proved Producing	0	0	0	0	0	0	0	0
Total Proved	17,325	13,260	0	0	30,585	0	30,585	29,135
Total Proved + Probable	17,325	13,260	13,525	0	44,110	0	44,110	40,402

Sources of Funding

All future development costs relate to the Elmworth property. It is expected that these will be financed through a combination of working capital, internally generated cash flows, and additional financing in the form of assumption of debt and/or equity raises.

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, 2016, Blackbird's core project, the "Elmworth Project", consisted of 83.75 sections (53,600 acres), the majority of which are contiguous. Blackbird holds a 100% working interest in the Elmworth Project.

Subsequent to July 31, 2016, the Corporation purchased 5.0 gross (3.5 net) additional sections of Elmworth Montney lands for cash consideration of $0.2 million, bringing the total land position to 88.75 gross sections (56,800 gross acres) or 87.25 net sections (55,840 net acres).

The Corporation believes the exploration risk of the Elmworth Project to have been significantly reduced through the drilling of the Corporation's first three wells as well as drilling in the vicinity by industry peers and majors. Currently and going forward, Blackbird expects the Elmworth Project to be its predominant focus.

On October 27, 2015, Blackbird announced that it successfully drilled, logged, and cased its third 100% working interest Elmworth well, the 02-20. This location was selected based on extensive geological research, competitor data, and proximity to planned infrastructure.

The 02-20 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 formation. Upon completion of logging operations, Blackbird drilled a horizontal leg of 2,008 meters, targeting the Middle Montney formation, to bottom-hole location 02-20-70-7W6. The measured depth of the 02-20 well is 4,660 meters. Blackbird realized cost savings from utilizing a monobore.

The 02-20 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.

Blackbird completed the well using sliding sleeve frac technology and an energized CO_2 foam frac with 70 individual stages. A total of 10,531 m^3 (88,317 bbls) of load fluid and 9,226 m^3 of CO_2 distributed an average of 31.75 tonnes of proppant per stage over the 70 stages.

On January 28, 2016, Blackbird released the production test results for the 02-20 well. Results from the final 24 hours of the test are as follows:

Well	Average Flowing Casing Pressure (kPa)(1)	Raw Gas (mmcf/d)(2)	Liquid Hydrocarbons (bbls/d)(2)(3)	Total Combined Production (boe/d)(2)	Liquids to Gas Ratio (bbls/mmcf)
02-20	7,973	6.8	641	1,768	94

Notes:

1) The 02-20 well produced through a 19.05 millimeter choke at the beginning of the final 24-hour test period and a 21.30 millimeter choke at the end of the final 24-hour test period.
2) The 02-20 well average rates over the final 24 hours of the test.
3) The 02-20 well total liquid hydrocarbons are comprised of 316 Bbls of free condensate and 325 Bbls of estimated natural gas liquids based on the composition from the 06-26 gas analysis.

The 02-20 well flowed on clean-up for a total of 751 hours and recovered approximately 43% of its load fluid, in addition to 481.4 m^3 (3,027 bbls) of condensate and 2,150 e3m3 of CO_2. During the final 24 hour test the casing pressure averaged 7,973 kPa. Blackbird expects that the 02-20 well will continue to clean up and that productivity will increase as additional load fluid is recovered.

During the final 24-hour test, the flow rate of the 02-20 well was restricted in order to limit production to 275 10^3m^3 of total gas per day (combined raw gas, CO_2 and N_2), in accordance with the Corporation's flare permit.

East Wapiti Project

The Corporation's Wapiti Project consists of 77.0 sections (49,280 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 Corporation holds a 100% working interest in 1.0 section (640 acres) of its Alsask Project land which is located near the Alberta/Saskatchewan border. The Alsask land is located in Alberta. All wells belonging to this property remained shut-in during the year ended July 31, 2016. The property also has a water disposal well.

Pembina Project

The Corporation holds a 24% working interest in certain petroleum and natural gas rights in 1.0 section (640 acres) of land and a standing Nisku formation sour gas/condensate well in the Pembina Field, Alberta.

Ferrier Project

The Corporation currently holds a 26.6% working interest in one well, which is subject to a 7.1% non-convertible gross overriding royalty.

Watts Project

The Corporation currently holds 50% working interests in certain petroleum and natural gas rights in 2.0 sections (1,280 acres) of land and a reversionary working interest of 50% before pay out / 25% after pay out in a producing gas well.

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	4	4	3	1.04	10	6.74
TOTAL	**0**	**0**	**5**	**5**	**3**	**1.04**	**10**	**6.74**

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.

Expiries

Of the 83.75 net sections of Elmworth Montney land held at July 31, 2016, there are 19.0 net sections which expiry dates occurring within the next fiscal year. The Corporation has 1.0 net section of land with an indefinite expiry date, based on the productive life of the well. The remaining 63.75 net sections have expiry dates ranging from fiscal 2017 to 2021.

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.

For additional information on abandonment and reclamation costs, see Item 5.2.

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 6.5 TAX HORIZON

Based on after tax economic forecasts prepared by GLJ, the Corporation will not be taxable in the total Proved reserves category and income taxes are payable by the Corporation in 2021 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, 2016:

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
	(M$)	(M$)	(M$)	(M$)
Elmworth	-	449	-	17,227
Wapiti	-	-	-	-
Alberta & Saskatchewan	-	-	-	-

Item 6.7 EXPLORATION AND DEVELOPMENT ACTIVITIES

During the year ended July 31, 2016, the Corporation acquired 10.75 additional sections of Elmworth Montney undeveloped land for cash consideration of $0.4 million.

The Corporation incurred approximately $3.3 million for drilling of the 02-20 well, $6.7 million for the completion of the 02-20 well and $3.9 million for testing operations and other post-completion costs. In addition the Corporation incurred $0.6 million for the drilling and logging of a pilot well from this wellbore. All other development costs incurred during the period were related to the Elmworth infrastructure project. The Corporation incurred approximately $0.6 million for drilling of the Elmworth water disposal well, $0.2 million for the completion of the Elmworth water disposal well and front end engineering design costs associated with the Elmworth facility and pipeline gathering system.

On September 29, 2016, the Corporation announced that it had received regulatory approval from the Alberta Energy Regulator for its 100% owned and operated Elmworth facility and pipeline gathering system. The Corporation commenced construction on these projects immediately following the receipt of approval.

On September 29, 2016, the Corporation also announced the commencement of its fall drill program. The drill program will consist of the Corporation's fourth 100% working interest Elmworth Montney horizontal well targeting the Upper Montney formation. The well will be spud from surface location 10-8-70-07W6 with a lateral length of approximately 2,150 meters to location 02/02-20-70-7W6 (the "02/02-20 well"). This well was spud at the beginning of October, 2016.

The Corporation is planning a large scale 02/02-20 well completion program using Stage Completion Inc.'s Bowhead II fracturing system. The slickwater completion program will place approximately 4,000 tonnes of proppant through approximately 71 individual fracs.

The 02/02-20 well will be tied-in and placed on production upon the commissioning of the Corporation's Elmworth infrastructure, eliminating costly flow back and production testing.

Item 6.8 PRODUCTION ESTIMATES

The table below sets out the Evaluator's estimate of First Year Production in the estimates of future net revenue from the forecast case of the various reserves classes as disclosed above under Item 2.1.

RESERVE CATEGORY	SHALE GAS		NATURAL GAS LIQUIDS		OIL EQUIVELANT	
	Company Gross (Mcf/d)	Company Net (Mcf/d)	Company Gross (bbl/d)	Company Net (bbl/d)	Company Gross (boe/d)	Company Net (boe/d)
Elmworth	0	0	0	0	0	0
Total Proved Producing	0	0	0	0	0	0
Elmworth	2,136	1,986	273	254	629	585
Total Proved Developed Non-Producing	2,136	1,986	273	254	629	585
Elmworth	0	0	0	0	0	0
Total Proved Undeveloped	0	0	0	0	0	0
Elmworth	2,136	1,986	273	254	629	585
Total Proved	2,136	1,986	273	254	629	585
Elmworth	594	553	71	66	170	158
Total Probable	594	553	71	66	170	158
Elmworth	2,730	2,539	344	320	799	743
Total Proved Plus Probable	2,730	2,539	344	320	799	743

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, 2016 Year End			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Production				
Heavy oil (bbls/d)	-	0.73	-	0.06
Natural gas (Mcf/d)	28.05	0.69	51.64	47.69
Natural gas liquids (bbls/d)	0.16	-	0.48	0.50
Total production (BOE/d)	4.84	0.85	9.09	8.51
Revenue				
Heavy oil ($/bbl)	-	42.89	-	39.16
Natural Gas ($/Mcf)	3.20	2.68	2.39	1.41
Natural gas liquids ($/bbl)	36.65	-	30.67	35.19
Total revenue ($/BOE)	19.77	39.21	15.23	10.22
Royalties ($/BOE)	-	-	-	0.19
Production Costs ($/BOE)	16.60	196.38	10.88	6.74
Netbacks ($/BOE)	3.17	(157.17)	4.35	3.29

Production Volume by Product

The following table discloses in total, working interest production volumes for the year ended July 31, 2016 for each product type:

	Heavy oil	**Natural gas**	**NGLs**	**Total**
	bbls	**Mcf**	**bbls**	**BOE**
TOTAL	73	11,679	104	2,124

The following fields accounted for 20% or more of the total working interest production volumes for the year ended July 31, 2016 by product type:

	Heavy oil	**Natural gas**	**NGLs**
	bbls	**Mcf**	**bbls**
Ferrier	N/A	6,822	96
Watts	N/A	3,979	N/A
Badger	67	N/A	N/A