Doxa Energy Ltd.

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Management Discussion and Analysis

For the period ended June 30, 2017
(Expressed in U.S. Dollars)

Overview

The following Management's Discussion and Analysis ("MD&A") of Doxa Energy Ltd. (the "Company" or "Doxa"), prepared as of August 28, 2017, should be read together with the unaudited condensed consolidated financial statements for the period ended June 30, 2017 and related notes attached thereto, which are prepared in accordance with International Financial Reporting Standards, ("IFRS"), as issued by the International Accounting Standards Board. The Company's functional currency is the Canadian dollar and the US subsidiary's functional currency is the U.S. dollar. All amounts are stated in U.S. dollars unless otherwise indicated.

The reader should also refer to the audited consolidated financial statements for the years ended December 31, 2016 and 2015, found filed on SEDAR.

Additional information related to the Company is available for view on SEDAR at www.sedar.com, and the Company website www.doxaenergy.com.

Forward Looking Statements and Risk Factors

The forward-looking information in this MD&A is based on the conclusions of management. The Company cautions that due to risks and uncertainties, actual events may differ materially from current expectations. With respect to the Company's operations, actual events may differ from current expectations due to economic conditions, new opportunities, changing budget priorities of the Company or other factors.

Further information regarding these and other factors which may cause results to differ materially from those projected in forward-looking statements are included in the Company's filings with securities regulatory authorities. The Company does not undertake to update any forward-looking statement that may be made from time to time by the Company or on its behalf, except in accordance with applicable securities laws.

GLOSSARY OF ABBREVIATIONS

BBL	barrel
BOPD	barrels of oil per day
BOE	barrels of oil equivalent[(1)]
BOEPD	barrels of oil equivalent per day
MCF	1,000 cubic feet of natural gas
MCFD	1,000 cubic feet of natural gas per day

(2) BOE conversion ratio of 6 MCF: l BBL is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation.

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	Cubic metres	28.317
Cubic metres	Cubic feet	35.494
BBLs	Cubic metres	0.159
Cubic metres	Bbls	6.292
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

DESCRIPTION OF BUSINESS

Doxa Energy Ltd. (the "Company" or "Doxa") is a Canadian junior oil and gas company with its offices in Vancouver, B.C., and Fort Worth, Texas, and its shares are listed for trading on the TSX Venture Exchange under the symbol **DXA**. Its head office is found at Suite 1450 – 700 West Georgia Street, Vancouver, B.C., V7Y 1K8. The Company is engaged primarily in exploration for, and production of, petroleum and natural gas reserves in Oklahoma and Texas, USA.

Management is actively looking for additional oil and gas projects in North America. Management has experience evaluating and financing oil and gas projects and anticipates expanding the Company's activities through acreage acquisitions, along with development drilling of wells on its existing and acquired properties.

Oil and Gas Properties

Mississippian Lime Play, Oklahoma

As of June 30, 2017, Doxa continued to own interests in 26 Mississippian wells, 17 of which are currently producing an average of approximately 3 barrels of oil per day (BOPD) and 36 MCF of natural gas per day (MCFPD), or 10 barrels of oil equivalent per day (BOEPD) per well, net to the company. As previously disclosed, the Company has no plans to participate in any new wells on this project.

3D Seismic Project, Bee and Goliad Counties, Texas

As previously reported, the successfully farmed out a portion of its interests in four different drilling projects to a third party retaining 5.37% participating interest along with a reversionary interest equal to 1.775% which it will receive upon the occurrence of payout of the project. The farmout provided the Company with capital necessary to fund its share of the drilling and completion cost associated with the retained interest. Two wells were

successfully drilled in Q1, both completed as oil wells and initiated production in Q2, 2017. The initial well, being the MK O'Brien Unit No. 1 was drilled to a depth of 5,100 feet and completed in the Basal Frio formation from 4,938-4,943 feet subsurface. The well was tested on a 7/64th inch choke at an initial rate of 60 BOPD and 100 MCFD and put on line May 18, 2017 flowing 60+ BOPD and a nominal amount of gas. Approximately 3.4 miles to the southeast the second well, being the Hiller No. 1 was drilled to a depth of 5,400 and also completed in the Basal Frio formation from 5,216-5,221 feet subsurface. The Hiller well was tested on a 7/64th inch choke at an initial rate of 95 BOPD and 110 MCF, and put on line May 24, 2017 flowing 95+ BOPD and 110 MCFD. Both wells are currently producing as expected and plans are underway to drill the two remaining wells in Q3 2017. Doxa intends to participate directly for its share of the future activities without further dilution by farmout or sale.

Peeler Ranch Area, Atascosa County, Texas

Doxa continues to own interests in 2 producing Eagle Ford wells in Atascosa County, Texas, both on the Peeler Ranch leasehold.

The Company owns a 20% interest in the Peeler Ranch No. 1-H, which was completed in March, 2011, is producing an average of 12 BOPD, and a 9.4796% interest in the Peeler Ranch No. 2-H was completed in January, 2012 and is also currently producing an average of 12 BOPD.

County Line Prospect, McMullen County, Texas

Doxa owns a 14.0625% leasehold working interest and a respective 10.4867% net revenue interest in the County Line Prospect, McMullen County, Texas. In early 2011, the Martin-State Gas Unit No.1 was drilled vertically to a total depth of 11,800 feet, and completed as a gas well. The well has produced approximately 3.61 BCF of gas and in September, 2016 was successfully recompleted to a shallower behind pipe zone of interest, and is currently producing approximately 316 MCFD and 8 BOPD.

County Line North Prospect, McMullen County, Texas

Doxa also owns a 12.527% working interest along with an 8.999% net revenue interest in the County Line North Project, McMullen County, Texas. One well has been drilled on the project, being the Kynette No. 1, which was completed as a gas well in October, 2011. After producing a total of 2.52 BCF the well is still producing at a rate of approximately 536 MCFD and 8 BCPD on compression. This project is situated approximately 2 miles northeast of the Martin-State Unit No. 1.

New Beilau Prospect, Colorado County, Texas

The Company owns 6.25% interest in the Koehn Unit No. 1 well, and a 12.5% interest in the Koehn Unit No. 2 well, both situated on the New Beilau Prospect, Colorado County, Texas.

While the Koehn No. 1 is nominally productive, the No. 2 well is producing an average of 16 BOPD and 374 MCFD.

Rogers Project, Jackson County, Texas

Doxa also owns a 4.50% interest in a Yegua formation producer, being the Rogers No. 1 well, Jackson County, Texas. The well is marginally productive. No further operations are planned for this project.

West Texas Leasehold

During 2016 Doxa agreed to participate for a 15% interest in the ongoing acquisition of various base oil and gas leases within what is known as the Permian Basin. Along with its partners, the Company acquired just over 200 gross acres of base leases and initiated various sales of portions of the leases late in 2016, continuing into Q2, 2017. Doxa realized a gain of approximately $145,000 from lease sales in the second quarter of 2017. The Company continues its efforts to acquire leases for resale to third parties for profit as opportunities arise. Details on this project will be released as the project progresses.

OPERATIONS REVIEW

Selected Production Net to the Company

	Three months ended June 30		**Six months ended June 30**		**Year Ended December 31,**	
	2017	2016	**2017**	2016	**2016**	2015
Gas - MCF	**9,914**	22,434	**29,514**	41,871	**83,537**	103,132
Oil - BBL	**1,115**	1,201	**2,152**	2,249	**4,530**	5,576
Total - BOE	**2,767**	4,940	**7,071**	9,227	**18,453**	22,764

Selected Revenue Net to the Company

	Three months ended June 30		Six months ended June 30		Year ended December 31	
	2017		2017		2016	
	($000's)	($/BOE)	($000's)	($/BOE)	($000's)	($/BOE)
Oil and gas revenue	$89.8	$32.5	$204.7	$28.9	$369.9	$20.0
Severance taxes	(10.5)	(3.8)	(18.3)	(2.6)	(39.8)	(2.2)
Production expenses	(48.3)	(17.5)	(86.2)	(12.2)	(245.4)	(13.3)
Total $, $/BOE	$31	$11.2	$100.2	$14.1	$84.7	$4.5

Selected Annual Information

Year Ended December 31	2016	2015	2014
Total Revenues *	$330,076	$443,713	$1,362,586
Net Loss	(212,320)	(842,990)	(2,592,218)
Basic and Diluted Loss per share	(0.01)	(0.02)	(0.08)
Total Assets	2,124,844	2,326,245	2,830,657
Total Non-Current liabilities	81,795	2,556,809	2,490,813
Cash Dividends Declared per Share	$0.00	$0.00	$0.00

*Revenues presented net of severance taxes and transport

Summary of Quarterly Results

The following table sets forth a comparison of the revenues and net income (loss) for each of the Company's last eight quarters:

Quarter Ended	2017		2016				2015	
	30-Jun	31-Mar	31-Dec	30-Sep	30-Jun	31-Mar	31-Dec	30-Sep
Total Revenues	$89,868	$114,863	$127,064	$91,492	$88,220	$63,150	$93,327	$121,722
Net Income (Loss)	86,026	68,686	(102,421)	75,502	(80,851)	(104,550)	(400,895)	(106,294)
Earnings (Loss) per share	$0.01	$0.00	$(0.01)	$0.00	$(0.00)	$(0.00)	$(0.01)	$(0.00)

Performance Summary

Three months ended June 30, 2017:

For the three months ended June 30, 2017, the Company realized a net income of $86,026 as compared to net loss of $(80,810) for the same period in 2016. The income per share was $0.01 as compared to loss per share of $(0.01) for the same period in 2016. Earnings (Loss) before interest, taxes, depletion and amortization (EBITDA) for the period were $147,476 compared to $3,300 for the same period in 2016. The net income (loss) experienced by the Company fluctuates each quarter due to the timing of certain expenditures such as impairments which are tested for annually. The net income (loss) can also fluctuate due to peripheral or incidental transactions or events such as a realized gain or a write-down or write-off of an asset.

During the three month period ended June 30, 2017, the Company realized a gain of $145,674 on the sale of certain acreage in the East Midland Extension.

The Company had gross revenue from oil and gas production from thirty three wells during the three month period ended June 30, 2017 of $89,868, as compared with $88,585 from thirty three wells for the same period in 2016. During the three months ended June 30, 2017, the Company had net production of 1,115 BBLS oil and 9,914 MCF gas compared with 1,201 BBLS oil and 22,434 MCF gas for the same period in 2016. The average price of oil realized during the current period was $38.92 per BBL and for gas $4.50 per MCF compared to $38.12 per BBL and $1.71 per MCF for the prior year period.

Filing fees and shareholder services for the three month period were $1,913 as compared to $2,000 in 2016. Filing fees and shareholder services fluctuates depending on activity during the period.

Interest expense on long-term debt for the period was $59,562 as compared to $62,935 in 2016. During the period the Company did not pay interest on related party loans in agreement with the related parties. The interest on the related party loans is being accrued.

Professional fees for the period were $18,320 as compared to 23,923 in 2016. Professional fees include legal, accounting and auditing fees. Professional fees fluctuate each quarter depending on activity.

Six months ended June 30, 2017:

For the six months ended June 30, 2017, the Company realized a net income of $154,712 as compared to net loss of $(185,360) for the same period in 2016. The income per share was $0.01 as compared to loss per share of $(0.01) for the same period in 2016. Earnings (Loss) before interest, taxes, depletion and amortization (EBITDA) for the period were

$275,010 compared to $(26,057) for the same period in 2016. The net income (loss) experienced by the Company fluctuates each quarter due to the timing of certain expenditures such as impairments which are tested for annually. The net income (loss) can also fluctuate due to peripheral or incidental transactions or events such as a realized gain or a write-down or write-off of an asset.

During the six month period ended June 30, 2017, the Company realized a gain of $215,525 on the sale of certain acreage in the East Midland Extension.

The Company had gross revenue from oil and gas production from thirty three wells during the six month period ended June 30, 2017 of $204,731, as compared with $152,095 from thirty three wells for the same period in 2016. During the six months ended June 30, 2017, the Company had net production of 2,152 BBLS oil and 29,514 MCF gas compared with 2,249 BBLS oil and 41,871 MCF gas for the same period in 2016. The average price of oil realized during the current period was $44.00 per BBL and for gas $3.56 per MCF compared to $32.85 per BBL and $1.68 per MCF for the prior year period.

Filing fees and shareholder services for the six month period were $6,679 as compared to $6,538 in 2016. Filing fees and shareholder services fluctuates depending on activity during the period.

Interest expense on long-term debt for the period was $115,592 as compared to $117,035 in 2016. During the period the Company did not pay interest on related party loans in agreement with the related parties. The interest on the related party loans is being accrued.

Professional fees for the period were $18,320 as compared to 23,923 in 2016. Professional fees include legal, accounting and auditing fees. Professional fees fluctuate each quarter depending on activity.

Liquidity and Capital Resources

The Company ended the period with $182,019 (2016 - $11,456) cash and negative working capital of $(2,019,703) (2016 - $(1,958,502)).

Net cash from (used in) operating activities for the period ended June 30, 2017 was $77,842 as compared to net cash of $(16,005) from operating activities in 2016.

Net cash from investing activities for the period ended June 30, 2017 was $185,017 as compared to $3,638 during 2016.

Net cash provided from (used in) financing activity for the period ended June 30, 2017 was $(115,899) as compared to $Nil during 2016.

The Company does not have sufficient funds to meet its liabilities and investment obligations for the ensuing twelve months as they fall due. In assessing whether the going concern assumption is appropriate, Management takes into account all available information about the future, which is at least, but not limited to, twelve months from the end of the reporting period.

The Company's ability to continue operations and fund its liabilities is dependent on management's ability to secure additional financing from either debt or equity, or from asset divestment opportunities. In this regard, Management has secured a revolving line of credit in the face amount of $5,000,000 with a borrowing base of $550,000. Management is pursuing such additional sources of financing and, while it has been successful in doing so in the past, there can be no assurance it will be able to do so in the future.

Critical Accounting Judgments and Estimates

The Company's use of judgments and estimates are presented in Note 2 of the accompanying consolidated financial statements. The preparation of the consolidated financial statements in accordance with IFRS requires management to select accounting policies and make judgments and estimates. Such judgments and estimates may have a significant impact on the consolidated financial statements. Actual amounts could differ materially from the estimates used and, accordingly, affect the results of the operations.

These include:

- identification of cash-generating units ("CGUs");
- classification of exploration and evaluation assets;
- going concern assumption;
- the valuation of deferred income tax assets;
- the determination of the Company and its subsidiary's functional currency
- the estimation of the oil and natural gas reserves;
- recoverability of asset carrying values;
- depreciation and depletion;
- the recoverability of accounts receivable; and
- the provision for decommissioning liabilities;

Key Accounting Policies

a) Revenue Recognition

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer, which is usually when legal title passes to the external party. This is generally at the time product enters the pipeline. Revenue is measured net of discounts customs

duties and royalties. With respect to the latter, the entity is acting as a collection agent on behalf of others.

Tariffs and tolls charged to other entities for use of pipelines and facilities owned by the Company are recognized as revenue, as they accrue in accordance with the terms of the service or tariff and tolling agreements.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

b) Property and equipment and exploration and evaluation assets

(i) Pre-exploration expenditures

Expenditures made by the Company before acquiring the legal right to explore in a specific area do not meet the definition of an asset and therefore are expensed by the Company as incurred.

(ii) Exploration and evaluation expenditures

Costs incurred once the legal right to explore has been acquired are capitalized as exploration and evaluation assets. These costs include, but are not limited to, exploration license expenditures, leasehold property acquisition costs, evaluation costs, including drilling costs directly attributable to an identifiable well and directly attributable general and administrative costs. These costs are accumulated in cost centers by property and are not subject to depletion until technical feasibility and commercial viability has been determined.

Exploration and evaluation assets are assessed for impairment when facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are grouped together with developing and producing assets and are tested at an aggregated CGU level. The Company evaluates the geography, geology, production profile and infrastructure of its assets in determining its CGUs. Doxa's CGUs are generally composed of significant development areas. The Company reviews the composition of its CGUs at each reporting date to assess whether any changes are required in light of new facts and circumstances.

The assessment of technical feasibility and commercial viability is based upon estimates of the recoverability of capitalized costs by future exploitation or sale and where the activities have reached a stage that permits a reasonable assessment of the existence of proved reserves. This policy requires management to make certain estimates and assumptions as to future events and circumstances, in particular whether an economically viable extraction operation can be established. Any such estimates and assumptions may change as new information becomes available.

When technical feasibility and commercial viability of a well is determinable based on management's assessment of current information, the exploration and evaluation assets attributable to that well are first tested for impairment and then reclassified from exploration and evaluation assets to property and equipment.

(iii) Other intangible costs

Costs of data purchased to formulate strategy for license applications, such as seismic data, and asset purchases are accumulated and capitalized as other intangible assets to the extent that they are incurred prior to obtaining related licenses and do not relate to a field with proven reserves attributed.

(iv) Developing and production costs

Items of property and equipment, which include petroleum and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. A CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount.

When significant parts of an item of property and equipment, including petroleum and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property and equipment, including petroleum and natural gas properties, are determined by comparing the proceeds from disposal with the carrying amount of

property and equipment and are recognized net within the statements of operations and comprehensive loss.

(v) Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property and equipment are recognized as petroleum and natural gas properties only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in comprehensive income (loss) as incurred. Such capitalized petroleum and natural gas properties generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property and equipment are recognized in comprehensive income (loss) as incurred.

(vi) Depletion and depreciation

Depletion of petroleum and natural gas properties is provided using the unit-of-production method based on production volumes in relation to total estimated proved reserves as determined annually by independent engineers.

Natural gas reserves and production are converted at the energy equivalent of six thousand cubic feet to one barrel of oil. Costs are only depleted once production in a given area begins.

Calculations for depletion and depreciation of production equipment are based on total capitalized costs plus estimated future development costs of proved and undeveloped reserves less the estimated net realizable value of production equipment and facilities after the proved reserves are fully produced.

Proved reserves are estimated using independent reserve engineering reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids, which geological, geophysical and engineering data demonstrate with a specified

degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- A reasonable assessment of the future economics of such production;
- A reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and
- Evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered proved if supported by either actual production or conclusive formation tests.

The area of reservoir considered proved includes:

(i) that portion delineated by drilling and defined by as-oil and/or oil-water contacts, if any, or both; and

(ii) immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower proved limit of the reservoir.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proved classification when successful testing by a pilot project, the operation of an installed program in the reservoir or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

Depletion and depreciation for other equipment is recognized in profit or loss on a declining balance basis with the following annual rates:

Office equipment	20%
Computer equipment	45%

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

c) Impairment of non-financial assets

Exploration and evaluation assets are assessed for impairment when they are reclassified to developing and producing assets, as petroleum and natural gas properties, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

Fair value less costs to sell is determined to be the amount for which the asset could be sold in an arm's length transaction. Fair value less costs to sell can be determined by using an observable market or by using discounted future net cash flows of proved and probable reserves using forecasted prices and costs. Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU.

Exploration and evaluation assets are grouped together with the Company's CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to developing and producing assets (oil and natural gas properties).

An impairment loss would be recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. Impairment losses are recognized in profit or loss.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset’s carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

At December 31, 2016, the Company calculated the recoverable amounts which were determined with fair value less costs to sell using a discounted cash flow method and categorized in Level 3 of the fair value hierarchy. Key assumptions in the determination of cash flows from reserves include crude oil and natural gas prices, loss factors and discount rates specific to the underlying composition of assets residing the CGU. The post-tax discount rate used was 17%.

At December 31, 2016, an impairment of $210,739 was determined on the Martin State Prospect and Mississippian Prospects, CGU's.

Off Balance Sheet Arrangements

There are no off balance sheet arrangements to which the Company is committed.

Related Party Transactions

At June 30, 2017, the Company has CDN$2,281,302 in loans payable, and CDN$113,127 in accrued interest owing to Armada, a Company controlled by the chairman of the Company.

At June 30, 2017, the Company has CDN$670,971 in loans payable, and CDN$33,283 in accrued interest owing to Harvco, a Company controlled by the president and director of the Company.

At June 30, 2017, the Company has $1,738,629 in accounts payable owing to Dynamic Production, Inc. a Company controlled by the president and director of the Company for lease operating expenses relating to the Company's developed and producing oil and gas properties.

Capital Stock, Options, and Warrants:

a) Common shares issued and outstanding as at June 30, 2017 and the date this MD&A – 33,980,141 common shares.

b) Options outstanding as at June 30, 2017 and the date of this MD&A – 600,000 stock options with exercise price of $0.15, expiring September 24, 2017

c) Warrants outstanding as at June 30, 2017 and the date of this MD&A – None

List of Officers and Directors

John D. Harvison	Director, President and CEO, Ft. Worth, Texas
G. Arnold Armstrong	Director and Chairman, Vancouver, BC
Mark Bronson	Director and CFO, Ft. Worth, Texas
Gerald Graham	Director, President of Doxa Energy US, Inc. Fort Worth, Texas
Jonathon Weiss	Director, Ft. Worth, Texas
Dan Frederiksen	Director, Vancouver, BC
Paul McKenzie	Director, Vancouver, BC
Shauna Hartman	Corporate Secretary, Surrey, BC

FINANCIAL INSTRUMENTS

Details of the Company's financial instruments, management's assessment of their related risks and details of management of those risks are as follows:

Financial Risk Management

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Company's financial instruments consist of cash, accounts receivable and accounts payable and accrued liabilities.

The fair values of cash, accounts receivable and accounts payable and accrued liabilities approximate their book values because of the short-term nature of these instruments.

Financial Instrument Risk Exposure

The Company is exposed in varying degrees to a variety of financial instrument related risks. The Board approves and monitors the risk management processes.

Credit Risk

The Company's only exposure to credit risk is on its bank accounts and accounts receivable. Bank accounts are with highly rated Canadian and US financial institutions.

Liquidity Risk

The Company has sufficient capital in order to meet short-term business requirements, taking into account the Company's holdings of cash. The Company's cash is invested in business accounts which are available on demand.

Market Risk

The only significant market risk exposure to which the Company is exposed is interest rate risk. The Company's bank account earns interest income at variable rates. The fair value of its portfolio is relatively unaffected by changes in short-term interest rates. The Company's future interest income is exposed to short-term rate fluctuations.

Exchange Risk

As at June 30, 2017, some of the Company's cash was held in Canada in Canadian dollars and some was held in the US in US dollars. As a result, the Company is subject to fluctuations in exchange rates.

Risk Factors

The Company is in the business of acquiring, exploring and, if warranted, developing and exploiting natural resource properties in North America. Due to the nature of the Company's proposed business and the present stage of exploration of its oil and gas properties the following risk factors, among others, will apply:

Exploration, Development and Operating Risks
The exploration for and development of oil and gas reserves involves significant risks which even a combination of careful evaluation, experience and knowledge may not eliminate. Few properties that are explored are ultimately developed into producing wells. Major expenses may be required to locate and establish petroleum reserves, to develop processes and to construct battery facilities at a particular site. It is impossible to ensure that the exploration or development programs planned by the Company will result in a profitable commercial oil operation. Whether an oil reserve will be commercially viable depends on a number of factors, some of which are: the particular attributes of the reserve, such as quantity and quality of the minerals and proximity to infrastructure; oil prices, which are highly cyclical; and government regulations, including regulations relating to prices, taxes, royalties, land tenure, land use, and environmental protection. The exact effect of these factors cannot be accurately predicted but could have a material adverse effect upon the Company's operations.

Oil and gas operations generally involve a high degree of risk. The operations of the Company are subject to all the hazards and risks normally encountered in the exploration, development and production of oil and gas, including unusual and unexpected geologic formations, seismic activity, rock bursts, cave-ins, flooding and other conditions involved in the drilling and removal of material, any of which could result in damage to, or destruction of other producing facilities, damage to life or property, environmental damage and possible legal liability.

Dependence on the Operator and Operational Risks
The Company holds a minority interest in its oil and gas properties and is not the operator of them. As such, the Company is dependent on the operator of these properties for further development and management of these properties. Operational risks in the oil and gas industry include exploration and reserve estimate risks, costs and availability of services and materials, premature reservoir declines, blowouts, well bore collapse, equipment failure and other accidents and adverse weather conditions. The Company is able to obtain material information regarding the operations of these properties when necessary, and is confident that the operations on these properties are carried out in keeping with industry standards.

Political Stability and Government Regulation Risks
The operations of the Company are currently conducted in North America, and as such, the operations of the Company are not exposed to severe uncertainties. Operations may be affected in varying degrees by government regulations with respect to, but not limited to, restrictions on production, price controls, export controls, currency remittance, income taxes, expropriation of property, foreign investment, maintenance of claims, environmental legislation, land use, land claims of local people, water use and safety. Failure to comply strictly with applicable laws, regulations and local practices relating to mineral rights applications and tenure could result in loss, reduction or expropriation of entitlements.

Insurance and Uninsured Risks
The business of the Company is subject to a number of risks and hazards in general, including adverse environmental conditions, industrial accidents, labor disputes, unusual or unexpected geological conditions, ground or slope failures, changes in the regulatory environment and natural phenomena such as inclement weather conditions and floods.

Such occurrences could result in damage to oil properties or facilities and equipment, personal injury or death, environmental damage to properties of the Company or others, and monetary losses and possible legal liability.

Although the Company may maintain insurance to protect against certain risks in such amounts as it considers being reasonable, its insurance may not cover all the potential risks associated with the Company's operations. The Company may also be unable to maintain insurance to cover these risks at economically feasible premiums. Insurance coverage may not be available or may not be adequate to cover any resulting liability.

Moreover, insurance against risks such as environmental pollution or other hazards as a result of exploration and production is not generally available to the Company or to other companies in the oil and gas industry on acceptable terms. The Company might also become subject to liability for pollution or other hazards which it may not be insured against or which the Company may elect not to insure against because of premium costs or other reasons. Losses from these events may cause the Company to incur significant costs

that could have a material adverse effect upon its financial performance and results of operations.

Environmental Risks and Hazards
All phases of the Company's operations are subject to environmental regulation in the various jurisdictions in which it operates. These regulations mandate, among other things, the maintenance of air and water quality standards and land reclamation. They also set forth limitations on the generation, transportation, storage and disposal of waste. Environmental legislation is evolving in a manner that will require stricter standards and enforcement and involve increased fines and penalties for non-compliance, more stringent environmental assessments of proposed projects, and a heightened degree of responsibility for companies and their officers, directors and employees. There is no assurance that future changes in environmental regulation, if any, will not adversely affect the Company's operations. Environmental hazards may exist on properties in which the Company holds interests which are unknown to the Company at present and which have been caused by previous or existing owners or operators of the properties.

Forward Looking Statements

Except for statements of historical fact relating to the Company, certain information contained herein constitutes forward-looking statements. Forward-looking statements are frequently characterized by words such as "plan", "expect", "project", "intend", "believe", "anticipate" and other similar words, or statements that certain events or conditions "may" or "will" occur. Forward-looking statements are based on the opinions and estimates of management at the date the statements are made, and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those projected in the forward-looking statements. These factors include the inherent risks involved in the exploration and development of oil and gas properties, the uncertainties involved in interpreting drilling results and other ecological data, fluctuating oil and gas prices, the possibility of project costs overruns or unanticipated costs and expenses, uncertainties relating to the availability and costs of financing needed in the future and other factors. The Company undertakes no obligation to update forward-looking statements if circumstances or management's estimates or opinions should change. The reader is cautioned not to place undue reliance on forward-looking statements.