Hunter Oil Corp.
(formerly known as Enhanced Oil Resources Inc.)

Management's Discussion & Analysis

Year Ended December 31, 2016

DATE AND BASIS OF INFORMATION

Hunter Oil Corp., formally known as Enhanced Oil Resources Inc., is a company incorporated in British Columbia, Canada and is engaged, through its wholly-owned U.S. subsidiaries (collectively referred to as the "Company", "we", or "our"), in the acquisition, development, operation and exploitation of crude oil and natural gas properties in the Permian Basin in eastern New Mexico, United States.

The Company's corporate headquarters is located in Vancouver, Canada and its operational headquarters is located in Houston, Texas. Common shares of the Company are listed on the TSX Venture Exchange ("TSX-V") under the symbol "HOC" and quoted on the Over the Counter marketplace ("OTCQX") under the symbol "HOILF." The registered address of the office is Suite 940, 1040 West Georgia Street, Vancouver, British Columbia, V6E 4H1. Additional information relating to the Company can be found on the SEDAR website at www.sedar.com.

Effective August 14, 2016, the Company changed its name to Hunter Oil Corp. Concurrently, its trading symbol on the TSX-V changed from "EOR" to "HOC" and its trading symbol on the OTCQX changed from "EORIF" to "HOILF."

Basis of Presentation

The following Management's Discussion and Analysis ("MD&A") is dated August 16, 2017 and should be read in conjunction with the Company's consolidated financial statements and related notes for the year ended December 31, 2016, as well as the consolidated financial statements and related notes, and MD&A for the year ended December 31, 2015. The referenced consolidated financial statements have been prepared by management and approved by the Company's Board of Directors. Unless otherwise noted, all financial information presented herein has been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

All financial information is in US dollars, unless otherwise indicated.

Non-IFRS Financial Measures

Certain financial measures in this MD&A, namely netback, cash flow from operations, lifting costs and EBITDA are not prescribed, do not have a standardized meaning defined by IFRS and therefore may not be comparable with the calculation of similar measures by other companies.

Netbacks are used by the Company as a key measure of performance and are not intended to represent operating profit nor should they be viewed as an alternative to cash flow provided by operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. A netback is a per barrel (or mcf) computation determined by deducting royalties, production expenses, transportation and selling expenses from the oil or gas sales price to measure the average net cash received from the barrels or mcf sold.

Lifting costs include all production costs necessary to produce oil or gas, however exclude severance taxes.

EBITDA refers to income (loss) before income taxes, depletion, depreciation, amortization and accretion.

Please refer to the Abbreviations and Definitions section at the end of this document which lists abbreviations and definitions commonly referred to in the energy business and which may be used in this MD&A.

BUSINESS OVERVIEW

Overview of Year Ended December 31, 2016

Crude Oil and Natural Gas Business Segment. The Company has one reportable business segment; crude oil and natural gas production and development, with all activities located in the United States of America. As such, we produce oil and gas from Permian Basin crude oil fields located in eastern New Mexico. The New Mexico fields were purchased in 2007 ("Chaveroo Field" and "Milnesand Field") because they represented excellent candidates for future development based on estimates of substantial remaining original-oil-in-place ("OOIP"). The OOIP associated with these fields represents more than 300 million barrels, of which some estimates project as much as 20% of OOIP could remain recoverable. The Company's net proved reserves at December 31, 2016 and 2015, respectively, were 12.6 million and 6.2 million barrels of oil equivalents, with a net present value of $233.4 million and $180.2 million respectively, using a 10% discount rate for both periods. This represented a 103.2% increase in reserves as of December 31, 2016.

Subsidiaries and Operations. The operations of the Company include Hunter Oil Corp. (the Parent Company) and its wholly-owned subsidiary, Hunter Oil Management Corp. ("HOMC") (formerly Ridgeway Petroleum (Florida), Inc.). HOMC includes the results of its wholly-owned subsidiaries, Hunter Oil Resources Corp. (formerly Enhanced Oil Resources USA Inc.), Milnesand Minerals Inc., Chaveroo Minerals Inc., and Hunter Oil Production Corp. ("HOPC") (formerly Arizona Resources Industries, Inc.). HOPC includes the results of its wholly-owned subsidiaries, Ridgeway Arizona Oil Corp. and EOR Operating Company. All intercompany amounts have been eliminated upon consolidation.

OVERALL PERFORMANCE

Consolidated Statements of Operations and Comprehensive Loss:

(In thousands of US dollars)	Three Months Ended December 31, 2016	Three Months Ended December 31, 2015	Years Ended December 31, 2016	Years Ended December 31, 2015
Revenues				
Oil and gas gross sales	$ 455	$ 325	$ 1,415	$ 1,358
Less royalties	(98)	(75)	(310)	(293)
	357	250	1,105	1,065
Expenses				
Operating costs, production costs and taxes	312	161	942	1,393
Workover expenses	114	249	353	809
General and administrative	777	788	2,648	2,613
(Gain) loss on disposition of assets	(14)	(106)	31	(42)
Depreciation and depletion	201	540	758	959
Accretion	98	93	372	427
Other, net	(32)	-	(36)	9
(Gain) loss on derivative financial instruments, net	-	(28)	-	75
Foreign currency translation (gain) loss	2	(23)	8	-
	1,458	1,674	5,076	6,243
Net comprehensive loss for the period	$ (1,101)	$ (1,424)	$ (3,971)	$ (5,178)
Loss per share - basic and diluted	$ (0.19)	$ (0.89)	$ (0.70)	$ (3.23)

Results of operations for the year ended December 31, 2016, included crude oil and natural gas sales revenues of $1.4 million, and a net loss of $4.0 million, compared to revenues of $1.4 million and a net loss of $5.2 million for the year ended December 31, 2015. The decrease in net loss of $1.2 million is principally due to field personnel reductions, operating cost improvements, reduced workover expenses and the closing of the Midland, Texas office during the second quarter of 2015. Per share losses (basic and fully diluted) were $0.70 and $3.23 for the years ended December 31, 2016 and 2015, respectively. Cash used in operating activities for the year ended December 31, 2016 was $3.7 million compared to $4.3 million in 2015, a decrease of $0.6 million.

Results of operations for the three months ended December 31, 2016, included crude oil and natural gas sales revenues of $0.5 million, and a net loss of $1.1 million, compared to revenues of $0.3 million and a net loss of $1.4 million for the three months ended December 31, 2015. Per share losses (basic and fully-diluted) were $0.19 and $0.89 for the three months ended December 31, 2016 and 2015, respectively.

DISCUSSION OF OPERATIONS

Revenues

In 2016, gross sales of crude oil and natural gas increased $0.06 million, or 4.2%, when compared to 2015. The increase is due to a 19.0% increase in sales volumes (37,112 Boe's in 2016 compared to 31,175 Boe's in the prior year), partially offset by a 12.6% reduction in the average price received for commodity sales ($38.10 per Boe in 2016 compared to $43.57 per Boe in 2015).

Gross sales of crude oil and natural gas in the fourth quarter of 2016 increased 40% to $0.5 million when compared to 2015. The increase is due to a 19.4% increase in sales volumes (10,389 Boe's in 2016 compared to 8,704 Boe's in the prior year) and a 16.9% increase in the average price received for commodity sales ($43.77 per Boe in 2016 compared to $37.43 per Boe during the same three months in the prior year).

Operating Costs, Production Costs and Workover Expenses

Our efforts have been focused on increasing oil recovery from legacy oil fields, which normally reflect higher operating costs than fields with newly established production. Since a majority of the Company's properties are older oil fields, we expect that operating costs will always be relatively higher due to the higher frequency of workovers, increasing compliance costs associated with increased regulatory activity and higher maintenance costs pending additional field development.

Operating and Production Costs: Operating and production costs for the year ended December 31, 2016, decreased approximately $0.5 million (or 32.4%) to $0.9 million, compared to $1.4 million for 2015. The decrease in costs is primarily due to field personnel reductions and operating cost improvements coupled with the closing of the Midland, Texas office during the second quarter of 2015.

Operating and production costs for the three months ended December 31, 2016, increased $0.15 million (or 93.8%) to $0.3 million when compared to the same three months in 2015. The increase in costs is principally due to the activity of eight wells brought online that were acquired in October 2016.

Workover Expenses: Workover expenses for the year ended December 31, 2016, decreased approximately $0.5 million (or 56.4%) when compared to the prior year. This represents a $16.29 per gross Boe (or 65.7%) reduction in workover expenses to $8.51 per gross Boe when compared to 2015. The decrease in costs is primarily due to the large amount of workover projects the Company undertook during 2015 in order to satisfy leasehold requirements for certain properties in both the Milnesand and Chaveroo fields.

Workover expenses for the three months ended December 31, 2016, decreased 54.2% to $0.1 million when compared to the same three months in the prior year. The decrease in costs is primarily due to reduced workover activity in the Chaveroo Field.

Netback: As a result of the increase in sales volume coupled with the decrease in workover costs, the operating netback for the twelve months ended December 31, 2016 decreased to a $4.39 loss per Boe compared to a $22.51 loss per Boe for 2015.

Operating netback for the quarter ending December 31, 2016 was a $6.15 loss compared to a $22.76 loss per Boe for the same period in 2015. The decrease in loss is primarily due increased sales volumes, higher average price received for commodity sales and lower workover costs during the period.

General & Administrative

General and administrative expenses were approximately $2.6 million for the years ended December 31, 2016 and 2015. General and administrative expenses for the quarters ended December 31, 2016 and 2015, were approximately $0.8 million and $0.8 million, respectively.

Depreciation and Depletion

Depreciation and depletion expense for the year ended December 31, 2016, decreased approximately $0.2 million (or 21.0%) to $0.8 million when compared to 2015. The decrease in expense for 2016 is primarily due to lower well bond premiums and a lower depreciable asset base when compared to the prior year, coupled with increased reserve balances at December 31, 2016. Depreciation and depletion expense for the three months ended December 31, 2016, and 2015 was $0.2 million and $0.5 million, respectively (discussed above).

Accretion

Accretion expense was approximately $0.4 million for the years ended December 31, 2016 and 2015, respectively. Accretion expense for the three months ended December 31, 2016 and 2015 was $0.1 million.

Gain (Loss) on Financial Instruments

The Company realized a loss of $0.1 million on NYMEX WTI settlements related to its crude oil derivative contracts for the year ended December 31, 2015. During 2015, all outstanding agreements expired leaving no derivative contracts in place at either December 31, 2015, or December 31, 2016.

Foreign Exchange Gain (Loss)

The Company's functional currency and presentational currency, as determined under International Accounting Standard ("IAS") 21, *The Effects of Changes in Foreign Exchange Rates*, is the United States dollar. All of the Company's operating expenses and capital expenditures are paid in the United States dollar except for general and administrative expense of the Canadian parent entity and all historical equity issuances of the Canadian parent which are denominated in Canadian dollars. There will continue to be an impact from currency translation and exchange gains and losses, but we believe this translation will have a small impact on our financial results. The average Canadian/US dollar exchange rate was $0.76 and $0.78 for the years ended December 31, 2016 and 2015, respectively.

Earnings before Interest, Taxes, Depreciation, Depletion and Amortization (EBITDA) Reconciliation

(In thousands of US dollars)	Three Months Ended December 31, 2016	Three Months Ended December 31, 2015	Years Ended December 31, 2016	Years Ended December 31, 2015
Net comprehensive loss	$ (1,101)	$ (1,424)	$ (3,971)	$ (5,178)
Adjustments:				
(Gain) loss on disposition of assets	(14)	(106)	31	(42)
Depreciation and depletion	201	540	758	959
Foreign currency translation (gain) loss	2	(23)	8	-
Accretion	98			
Unrealized gain on financial instruments	-	(62)	-	(39)
Other, net	(32)	-	(36)	9
EBITDA	**$ (846)**	**$ (1,075)**	**$ (3,210)**	**$ (4,291)**

Operating Netback and Production

The table below summarizes the operating netback for the comparable periods in the aggregate for the years ended December 31, 2016 and 2015.

Operating Netback Per Gross Boe:

(In US dollars)		Three Months Ended December 31, 2016	Three Months Ended December 31, 2015	Years Ended December 31, 2016	Years Ended December 31, 2015
Oil & Gas Sales Volumes					
Oil equivalent	*Boe's*	10,389	8,704	37,112	31,175
Average prices [(1)]					
Oil equivalent	*$/Boe*	$ 43.77	$ 37.43	$ 38.10	$ 43.57
Less:					
Royalties, net [(2)]	*$/Boe*	(9.38)	(6.93)	(8.07)	(7.94)
Production taxes	*$/Boe*	(3.27)	(3.08)	(2.71)	(3.72)
Production costs	*$/Boe*	(26.86)	(22.36)	(23.20)	(29.62)
Workover expense	*$/Boe*	(10.41)	(27.83)	(8.51)	(24.80)
Operating Netback [(3)]	*$/ Boe*	$ (6.15)	$ (22.76)	$ (4.39)	$ (22.51)

(1) Average prices are after deduction of transportation costs.

(2) Net of related production taxes.

(3) Operating netback equals crude oil and natural gas sales less royalties, operating costs and transportation costs calculated on a Boe basis. Operating netback does not have a standardized measure prescribed by IFRS and therefore may not be comparable with the calculations of similar measures for other companies.

Operating netback for the year ended December 31, 2016, decreased $18.12 per gross Boe (or 80.5%) to a $4.39 loss per gross Boe, compared to $22.51 loss per gross Boe in 2015. The decrease in net loss is principally due to field personnel reductions, operating cost improvements and reduced workover activity during the current period. For the same reasons, operating netbacks for the three months ended December 31, 2016, decreased $16.61 per gross Boe (or 73.0%) to a $6.15 loss, compared to a $22.76 loss per gross Boe realized in the same period in 2015.

LIQUIDITY AND CAPITAL RESOURCES

As of December 31, 2016, the Company had unrestricted cash of $1.1 million and restricted cash of $2.3 million.

On May 13, 2016, the Company closed a private placement of 6,470,000 common shares of the Company at a price of C$0.50 per share to raise gross proceeds of US $2.5 million. The intended use of proceeds is for operating expenses and general working capital. During 2015, the Company received $0.3 million in the private placement financing. In 2016, the Company received private placement proceeds of $1.75 million.

On January 11, 2016, an additional $1.25 million was released from escrow by Kinder Morgan (refer to "Commitments" herein and Notes 6 and 17 in the Company's consolidated financial statements for the year ended December 31, 2016).

In May of 2016, in connection with the deposits to secure asset retirement obligations, approximately $0.7 million of certain bond funds were released to the Company as it had fulfilled the requirements of those obligations. This resulted in a reduction of long-term restricted cash in 2016.

In order to provide the necessary funds to develop its projects, the Company is considering all available sources of financing, including equity, bank and mezzanine debt, asset sales and joint venture arrangements. The Company expects that financing of drilling activities will require dilution of equity interests or higher cost debt financing and will require that the development of these fields command a high rate of return on investment. The Company will continue to focus on operations activities that further its objectives of positive operating cash flows and increasing production in one or more of its oil fields.

While the 2016 consolidated financial statements are prepared on the basis that the Company will continue to operate as a going concern, which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of business for the twelve-month period following the date of these consolidated financial statements, certain conditions and events cast significant doubt on this assumption. For the year-ended December 31, 2016, the Company had negative cash flows from operations of approximately $3.7 million and, at December 31, 2016, an accumulated deficit of approximately $110.6 million. The Company also expects to incur further losses during the future development of its business. The Company's ability to continue as a going concern is dependent upon its ability to generate profitable production and to obtain additional funding from loans or equity financings or through other arrangements. Although the Company has been successful in obtaining financing, there is no assurance that it will be able to obtain adequate financing in the future or that such financing will be on terms acceptable to the Company.

QUARTERLY RESULTS OF OPERATIONS AND SELECT FINANCIAL DATA

Summary of Quarterly Information:

Quarterly Revenue, Loss and Earnings Per Share:

(In thousands except per share amounts)	2015				2016			
	First	**Second**	**Third**	**Fourth**	**First**	**Second**	**Third**	**Fourth**
Revenues	$ 267	$ 394	$ 372	$ 325	$ 236	$ 317	$ 407	$ 455
Net comprehensive income (loss)	$ (1,320)	$ (1,335)	$ (1,099)	$ (1,424)	$ (1,033)	$ (690)	$ (1,147)	$ (1,101)
Per share - basic	$ (0.82)	$ (0.83)	$ (0.69)	$ (0.89)	$ (0.65)	$ (0.12)	$ (0.20)	$ (0.19)
Per share - diluted	$ (0.82)	$ (0.83)	$ (0.69)	$ (0.89)	$ (0.65)	$ (0.12)	$ (0.20)	$ (0.19)

Revenue varies directly with the average price of oil received and production volumes achieved. The following table summarizes the average received prices and gross production for the three-month periods indicated:

Quarterly Average Prices Received and Sales Volumes:

	2015				2016			
	First	**Second**	**Third**	**Fourth**	**First**	**Second**	**Third**	**Fourth**
Average price received	$ 41.96	$ 52.28	$ 43.34	$ 37.43	$ 28.19	$ 39.96	$ 39.58	$ 43.77
Sales volume	6,365	7,535	8,571	8,704	8,378	8,036	10,309	10,389

The quarterly table reflects operational activity arising from planned and unplanned activities, such as regulatory requirements, changes in prices, availability of oil field services and/or weather related downtime, thereby affecting the level of workover and maintenance activity in each of the oilfields. The increase in crude oil sales in the fourth quarter of 2016 was due to the activity of eight wells brought online that were acquired in October 2016 in the Chaveroo field. The increase in crude oil sales in the third quarter of 2016 was due to the reactivation of wells in both the Milnesand and the Chaveroo fields. Crude oil sales volume decreased in the second quarter of 2016 principally due to an increase in crude storage. The decrease in crude oil sales volumes in the first quarter of 2016 was primarily due to weather related downtime in January 2016. The increases in crude oil sales volumes in the second, the third and the fourth quarters of 2015 were due to the reactivation of numerous wells in both the Milnesand and the Chaveroo fields. Crude oil sales volume decreased in the second quarter of 2016 due to an increase in crude storage.

The increase in revenue in the fourth quarter of 2016 was due to both higher sales volumes and higher oil prices. Revenue increased in the third quarter of 2016 due to higher sales volumes. Revenue increased in the second quarter of 2016 due to higher commodity prices received from oil sales. Revenue decreased in the first quarter of 2016 and the third and the fourth quarters of 2015 due to lower commodity prices received from oil sales. Revenue increased in the second quarter of 2015 due to higher sales volume coupled with higher oil prices.

Selected Annual Information

The following information is presented from annual information in the Company's audited financial statements for the periods indicated and prepared on the basis of the accounting principles effective for such period, as indicated:

Three Year Select Financial Data:

(In thousands except per share amounts)	Year Ended December 31, [1]		
	2016	**2015**	**2014**
Revenues	$ 1,415	$ 1,358	$ 8,001
Net comprehensive loss	$ (3,971)	$ (5,178)	$ (6,439)
Net loss per common share [2]	$ (0.70)	$ (3.23)	$ (4.02)
Loss per share basic and fully diluted [2]	$ (0.70)	$ (3.23)	$ (4.02)
Total assets	$ 43,542	$ 46,572	$ 58,588
Total non-current financial liabilities	$ 17,240	$ 18,977	$ 24,972

[1] The selected annual information was prepared in accordance with IFRS. Amounts are denominated in US dollars, which the Company determined under International Accounting Standard (IAS) 21 is its functional currency.

[2] Effective January 21, 2015, the Company implemented a share consolidation on the basis of one new common share for every ten pre-consolidation shares. Effective September 9, 2016, the Company implemented a further share consolidation on the basis of one new common share for every ten pre-consolidation shares as of September 9, 2016. Accordingly, all references to the outstanding common shares and the common share options of the Company in these financial statements have been restated to give effect to the two consolidations as if the number of shares or options were effective for all periods presented.

Revenues increased due to increased production from both reactivated wells in the Milnesand and Chaveroo fields and new wells acquired during 2016 as well as higher oil prices. Revenues decreased in 2015 primarily due to the lost production from the sale of the Crossroads field (37,915 gross Boe's sold in the prior year) coupled with the decrease in the average price received for crude oil sales. Losses in 2014 were principally associated with large workover costs associated with the Crossroads field, which was sold in October 2014.

Equity Placements

On May 13, 2016, the Company closed a private placement of US $2.5 million. On closing, a total of 6,470,000 common shares was issued at a price of C$0.50 per share. The intended use of proceeds is for operating expenses and general working capital.

During 2015, the Company received $0.3 million in connection with the private placement. During 2016, the Company received an additional $1.75 million in private placement subscription proceeds. The private placement proceeds are recorded in equity instruments on the Company's consolidated balance sheet at December 31, 2016.

Share Consolidation

Effective January 21, 2015, the Company implemented a share consolidation on the basis of one new common share for every ten pre-consolidation shares. Effective September 9, 2016, the Company implemented a further share consolidation on the basis of one new common share for every ten pre-consolidation shares as of September 9, 2016. Accordingly, all references to the outstanding common shares and the common share options of the Company have been restated to give effect to the two consolidations as if the number of shares were consolidated effective December 31, 2014 (see the Company's consolidated financial statements for the year ended December 31, 2016, Note 14 – *Equity Instruments*).

Commitments

In February 2014, the Company amended its CO_2 Purchase Agreement obligation with Kinder Morgan CO_2 Company, L.P. ("Kinder Morgan"), to extend the dates before which the Company was obligated to take or pay for CO_2 purchases and connect to Kinder Morgan's pipeline. The agreement provided the source of CO_2 for use in tertiary oil recovery projects in the Permian Basin. The contract, as amended, required the Company to take or pay for the purchase of 27.4 billion cubic feet of CO_2 over a five-year period commencing no later than January 1, 2018. The maximum daily purchase commitment required under the contract was 20 million cubic feet per day during year three with the cost of CO_2 fluctuating based on the price of crude oil and transportation tariffs at the time. The Company was required to construct a pipeline, estimated to be a distance of 32 miles, to the pipeline operated by Kinder Morgan. The purchase commitment and obligation to pay, as amended, were terminated as of December 31, 2016, and the Company has no further obligations under the agreement.

In connection with the sale of certain assets to Kinder Morgan in 2012, the Company agreed to be contingently responsible for up to \$5.0 million of future appraisal drilling costs to evaluate helium in certain areas of the St. Johns Dome field ("Drilling Costs"). The obligation was secured in part by \$2.5 million placed into escrow at closing of the sale. On September 4, 2015, approximately \$1.25 million of the Company's restricted cash was released from escrow by Kinder Morgan. In January 2016, the remaining sum of approximately \$1.25 million was released to the Company (see Notes 6 and 17 in the Company's consolidated financial statements for the year ended December 31, 2016). The remaining obligation of \$2.5 million expires in January of 2024. The Company's obligations to fund Drilling Costs are contingent on both (i) all permits being issued, and (ii) all steel being purchased to construct a pipeline to the St. Johns Dome field.

Regulatory Compliance in New Mexico

The Company's operating subsidiaries, primarily Ridgeway Arizona Oil Corp. ("Ridgeway") and EOR Operating Company, conduct their operations under the oversight of multiple federal and state agencies. The Company's Chaveroo field is operated by Ridgeway, which is both the federal and State of New Mexico operator of record. The Company's other principal oil field, Milnesand, is operated by EOR Operating Company, which is both the federal and State of New Mexico operator of record.

DISCLOSURE OF CONTROLS, PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

As a TSX Venture Exchange issuer, the Company's officers are not required to certify the design and evaluation of operating effectiveness of the Company's disclosure controls and procedures ("DC&P") or its internal controls over financial reporting ("ICFR"). The Company maintains DC&P designed controls to ensure that information required to be disclosed in reports filed or submitted is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In addition, the Chief Executive Officer and the Chief Financial Officer have designed controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Due to its size, the small number of employees, the scope of its current operations, its limited liquidity and capital resources, there are inherent limitations on the Company's ability to design and implement on a cost-effective basis the DC&P and ICFR procedures, the effect of which may result in additional risks related to the quality, reliability, transparency and timeliness of its interim filings and other reports. There have been no changes in ICFR during the year ended December 31, 2016.

OFF-BALANCE SHEET ARRANGEMENTS

The Company does not have any special purpose entities nor is it party to any arrangements that would be excluded from the consolidated balance sheet.

RELATED PARTY TRANSACTIONS

During the years ended December 31, 2016 and 2015, the Company paid approximately $0.36 million and $0.34 million, respectively, for management fees, rent and office expenses to an entity controlled by the Company's Chief Executive Officer.

SUBSEQUENT EVENTS

On May 5, 2017, as a result of delinquent filing of its consolidated financial statements, the Company was issued a Cease Trade Order by the British Columbia Securities Commission (see the Company's press release dated May 8, 2017). Upon filing of the consolidated annual financial statements, the Company will seek a revocation of the Cease Trade Order.

CRITICAL ACCOUNTING ESTIMATES

Estimates and underlying assumptions are reviewed on an ongoing basis and involve significant estimation uncertainty which have a significant risk of causing adjustments to the carrying amounts of assets and liabilities. Revisions to accounting estimates are recognized in the year in which the estimates are reviewed and for any future years affected. Significant judgments, estimates and assumptions made by management in the consolidated financial statements are outlined below:

Deferred income tax assets: Assessing the recoverability of deferred income tax assets requires significant estimates related to expectations of future taxable income based on forecasted cash flows from operations as well as interpretations and judgements on uncertain tax positions of applicable tax laws. Such judgements include determining the likelihood of tax positions being successfully challenged by tax authorities based on information from relevant tax interpretations and tax laws. To the extent such interpretations are challenged by the tax authorities or future cash flows and taxable income differ significantly from estimates, the ability to realize deferred tax assets recorded at the balance sheet date may be compromised. Refer to Note 13 in the Company's consolidated financial statements for the year ended December 31, 2016, for further details.

Financial instruments: The estimated fair values of financial assets and liabilities, by their very nature, are subject to measurement uncertainty due to their exposure to credit, liquidity and market risks. Furthermore, the Company may use derivative instruments to manage oil and gas commodity prices. The fair value of these derivatives is determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data, including quoted commodity prices and volatility. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and, as such, are subject to measurement uncertainty. Refer to Note 18 in the Company's consolidated financial statements for the year ended December 31, 2016, for further details.

Oil and natural gas reserves: Certain depletion, depreciation, impairment and asset retirement obligation charges are measured based on the Company's estimate of proved and probable oil and gas reserves and resources. The estimation of proved and probable reserves and resources is an inherently complex process and involves the exercise of professional judgment. Oil and natural gas reserves have been evaluated at December 31, 2016 and December 31, 2015 by independent petroleum engineers in accordance with National Instruments 51-101 "*Standards of Disclosure for Oil and Gas Activities*".

Oil and natural gas reserve estimates are based on a range of geological, technical and economic factors, including projected future rates of production, estimated commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Assumptions reflect market and regulatory conditions existing at the reporting date, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves and resources.

Impairment of assets: The Company evaluates its assets for possible impairment at the CGU level. The determination of CGUs requires judgement in defining the smallest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs has been determined based on similar geological structure, shared infrastructure, geographical proximity, commodity type, the existence of active markets, similar exposure to market risks, and the way in which management monitors the operations.

The recoverable amounts of CGUs and individual assets have been determined based on the higher of fair value less costs of disposal model and value in-use model. The key assumptions the Company uses in estimating future cash flows for recoverable amounts are: anticipated future commodity prices, expected production volumes, future operating and development costs, estimates of inflation on costs and expenditures, expected income taxes and discount rates. In addition, the Company considers the current environmental, social and governance issues affecting its property interests and operations, including the current legislative and regulatory activity affecting the permitting and approval of its projects and operations. Changes to these assumptions will affect the estimated recoverable amounts attributed to a CGU or individual assets and may then require a material adjustment to their related carrying value.

The decision to transfer exploration and evaluation assets to property and equipment is based on management's determination of a property's technical feasibility and commercial viability based on proved and probable reserves as well as related future cash flows.

Judgements are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgements as to future events and circumstances as to whether economic quantities of reserves will be found so as to assess if technical feasibility and commercial viability has been achieved.

Judgements are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings.

Asset retirement obligations: The Company estimates and recognizes liabilities for future asset retirement obligations and restoration of exploration and evaluation assets, and for oil and gas development and producing assets. These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration, technological advances and the possible future use of the asset. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new restoration techniques, operating experience and prices. The expected timing of future retirement and restoration may change due to these factors, as well as affect the estimates of reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented. The Company has chosen to use a risk-free rate for discounting asset retirement obligations.

FUTURE ACCOUNTING PRONOUNCEMENTS

The following new standards and amendments to standards and interpretations are effective for annual periods beginning after January 1, 2018, and have not been applied in preparing these financial statements.

IFRS 9: Financial Instruments

The complete version of *IFRS 9* was issued in July 2014. It replaced guidance in *IAS 39* that relates to the classification and measurement of financial instruments. *IFRS 9* retains but simplifies the mixed measurement model and establishes three primary measurement categories for financial assets: amortized cost, fair value through other comprehensive income (OCI) and fair value through profit and loss (P&L). The basis of classification depends on the entity's business model and the contractual cash flow characteristics of the financial asset. Investments in equity instruments are required to be measured at fair value through profit or loss with the irrevocable option at inception to present changes in fair value in OCI not recycling. There is now a new expected credit losses model that replaces the incurred loss impairment model used in *IAS 39*. For financial liabilities, there were no changes to classification and measurement except for the recognition of changes in own credit risk in other comprehensive income, for liabilities designated at fair value through profit or loss. *IFRS 9* relaxes the requirements for hedge effectiveness by replacing the bright line hedge effectiveness tests. It requires an economic relationship between the hedged item and hedging instrument and for the "hedged ratio" to be the same as the one management actually uses for risk management purposes. Contemporaneous documentation is still required but is different to that currently prepared under *IAS 39*. The standard is effective for accounting periods beginning on or after January 1, 2018. Early adoption is permitted. The Company has not fully assessed the impact of *IFRS 9*.

IFRS 15: Revenue from Contracts with Customers

IFRS 15 deals with revenue recognition and establishes principles for reporting useful information to users of financial statements about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers. Revenue is recognized when a customer obtains control of a good or service and thus has the ability to direct the use and obtain the benefits from the good or service. The standard replaces *IAS 18 Revenue* and *IAS 11 Construction Contracts* and related interpretations. The standard is effective for annual periods beginning on or after January 1, 2018 and earlier application is permitted. The Company has not fully assessed the impact of *IFRS 15*.

IFRS 16: Leases

In January 2016, the IASB issued *IFRS 16 Leases*. It replaces the existing leasing standard (*IAS 17 Leases*) and provides transparency on companies' lease assets and liabilities by removing off balance sheet lease financing and will improve comparability between companies that lease and those that borrow to buy. *IFRS 16* is effective January 1, 2019, with earlier application permitted. The Company is currently assessing the impact of this standard.

There are no other IFRS or IFRIC interpretations that are not yet effective that would be expected to have a material impact on the Company.

POTENTIAL RISKS AND UNCERTAINTIES

The resource industry is highly competitive and, in addition, exposes the Company to a number of risks. Resource exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. It is also highly capital intensive and the ability to complete a development project may be dependent on the Company's ability to raise additional capital. In certain cases, this may be achieved only through joint ventures or other relationships, which would reduce the Company's ownership interest in the project. There is no assurance that development operations will prove successful.

Risks Associated with Financial Assets and Liabilities – The Company is exposed to financial risks arising from its financial assets and liabilities. Financial risks include market risks (such as commodity prices, foreign exchange and interest rates), credit risk and liquidity risk. The future cash flows of financial assets or liabilities may fluctuate due to movements in market prices and the exposure to credit and liquidity risks. Disclosures relating to exposure risk are provided in detail below

Credit Risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments exposed to concentrations of credit risk are primarily cash and cash equivalents, including restricted cash, accounts receivable and counterparty risk on derivative contracts.

The Company limits its exposure to credit risk with respect to cash equivalents by investing available cash in short-term deposits with Canadian and US banks, principally in overnight money market funds investing in government treasury instruments. The Company's receivables mainly consist of amounts due from sales of its crude oil and natural gas production. The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit ratings (if available) or to historical information about counterparty default rates.

With respect to its crude oil and natural gas production receivables, the Company is the operator of all its property interests and owns the significant majority of the working interest in producing and non-producing properties.

Receivables related to the sale of crude oil production are with two major reputable marketers and proceeds are collected within approximately 25 days following the month of delivery. The Company produces a limited amount of natural gas which is sold to a reputable purchaser and collections occur within approximately 55 days of the end of any monthly period.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, as far as possible, that it will always have sufficient liquidity to meet liabilities when due. At December 31, 2016, the Company had cash of $1.5 million, excluding restricted cash of $2.3 million. The Company is still dependent on raising funds by borrowings, equity issues, or asset sales to finance its ongoing operations, capital expenditures and acquisitions. The contractual maturity of the majority of accounts payable is within three months or less. Management has delayed capital expenditures on certain projects until the oil commodity pricing environment improves and has reduced general and administrative and operating costs during 2015 and 2016. The Company has historically financed its expenditures and working capital requirements through the sale of common stock or, on occasion, through the issuance of short-term debt.

Foreign Exchange Risk

Substantially all of the Company's assets and expenditures are either denominated in or made with US dollars. As a result, the Company has very limited exposure to foreign exchange risk in relation to existing commitments or assets denominated in a foreign currency. The Company has chosen not to enter into any foreign exchange contracts since its Canadian dollar working capital balances are not significant to the consolidated entity.

Commodity Price Risk

The Company is exposed to fluctuations in the world commodity prices for its products with a corresponding impact to cash flow. Reduced cash flow may result in lower levels of capital being available for field activity, thus compromising the Company's capacity to grow production while at the same time replacing continuous production declines from existing properties. When the Company forecasts increased debt levels due to capital expenditures exceeding cash flow, it may enter into oil and natural gas hedging contracts in order to provide stability of future cash flow and, thus, predictable debt reduction. The Company engages in derivative financial instruments solely to manage its commodity price risk exposure relative to its actual commodity production and not for speculative purposes.

Exploration, Drilling and Operational Risks

The business of exploration for and production of oil, gas and other resources involves a high degree of risk. In particular, the operations of the Company may be disrupted, curtailed or cancelled by a variety of risks and hazards which are beyond the control of the Company, including environmental hazards, industrial accidents, occupational and health hazards, technical failures, labor disputes, unusual or unexpected rock formations, flooding and extended interruptions due to inclement or hazardous weather conditions, mechanical difficulties, shortage or delays in the delivery of rigs and/or other equipment, compliance with governmental requirements, explosions and other accidents. These risks and hazards could also result in damage to, or destruction of, production facilities, personal injury, environmental damage, business interruptions, monetary losses and possible legal liability.

Additional Financing

To the extent that external sources of capital, including the issuance of additional common shares, become limited or unavailable, the Company's ability to make necessary capital investments to maintain or expand its oil and gas exploration and development activities will be impaired.

Political Risks

The Company's principal licenses are located in New Mexico, USA. Future 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, foreign investment, maintenance of licenses, environmental legislation, land use, land claims of local people, water use and well safety.

Failure to comply strictly with applicable laws, regulations and local practices relating to exploration and evaluation assets could result in loss, reduction or expropriation of entitlements. The occurrence of these various factors and uncertainties cannot be accurately predicted and could have an adverse effect on the Company's consolidated results of operations and financial condition.

Dependence on Key Personnel

The Company has a small management team and the loss of a key individual or the inability to attract suitably qualified personnel in the future could materially and adversely affect the Company's business.

Foreign Investments

The Company expects that its oil and gas exploration activities will take place principally outside of Canada for the foreseeable future. As such, the Company's operations are subject to a number of risks over which it has no control. These risks may include risks related to economic, social or political instability or change, terrorism, hyperinflation, currency non-convertibility or instability, changes of laws affecting foreign ownership, government participation, taxation, working conditions, rates of exchange, exchange control, exploration licensing, petroleum and export licensing and export duties as well as government control over domestic oil and gas pricing. The Company endeavors to operate in such a manner in order to minimize and mitigate its exposure to these risks. However, there can be no assurance that the Company will be successful in protecting itself from the impact of all of these risks.

Environmental Regulation

The oil and gas industry is subject to environmental regulation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of the Company or its properties. Such legislation may be changed to impose higher standards and potentially costlier obligations. The Company endeavors to operate in such a manner to ensure it conforms to the standards and government regulations required for each jurisdiction in which it operates.

General Economic Conditions

There has been a high level of volatility in the world financial markets over the past few years. This volatility has caused investors to become less willing to provide debt or equity financing to most companies and in particular to junior resource companies. This will potentially make completing financings for the Company difficult in the foreseeable future.

Market Risks

The Company is subject to normal market risks including fluctuations in foreign exchange rates and interest rates. While the Company manages its operations in order to minimize exposure to these risks, the Company has not entered into any derivatives or contracts to hedge or otherwise mitigate this exposure.

Government Regulations

The Company's oil and gas concessions are subject to various federal and local governmental regulations. Matters subject to regulation include discharge permits for drilling operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells, and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas. The production, handling, storage, transportation and disposal of oil and gas, by-products thereof, and other substances and materials produced or used in connection with oil and gas operations are also subject to regulation under federal and local laws and regulations relating primarily to the protection of human health and the environment. The Company incurs expenditures related to complying with these laws, and for remediation of existing environmental contamination. The requirements imposed by such laws and regulations are frequently changed and subject to interpretation, and the Company is unable to predict the ultimate cost of compliance with these requirements or their effect on its operations.

OTHER MD&A INFORMATION NOT DISCLOSED ELSEWHERE

Disclosure of Share Capital

Authorized capital:

25 million preference shares of no par value;

Unlimited common shares of no par value;

Issued and outstanding at August 16, 2017:

1,000 preference shares (held by a wholly-owned subsidiary of the Company);

8,070,871 common shares issued.

All outstanding common stock options expired during the year ended December 31, 2016.

Forward-Looking Statements

Certain statements contained in this Management's Discussion and Analysis and in certain documents incorporated by reference into this Management's Discussion and Analysis, contain estimates and assumptions which management are required to make regarding future events and may constitute forward-looking statements within the meaning of applicable securities laws. Management's assessment of future operations, drilling and development plans and timing thereof, other capital expenditures and timing thereof, methods of financing capital expenditures and the ability to fund financial liabilities, expected commodity prices and the impact on the Company, and the impact of the adoption of future changes in accounting standards may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, the flexibility of capital funding plans and the source of funding therefore; production, marketing and transportation, loss of markets, volatility of commodity prices, the effect of the Company's risk management program, including the impact of derivative financial instruments; currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of the acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources.

All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar other expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A, as the case may be. The Company does not intend, and does not assume an obligation, to update these forward-looking statements, except as required by securities law.

In particular, this MD&A and the documents incorporated by reference include, but are not limited to, forward-looking statements pertaining to the following:

- the quantity of reserves and contingent resources;
- crude oil, natural gas, CO_2 and helium operations and production levels;
- capital expenditure programs, including drilling programs, asset retirement and abandonment activities and pipeline construction projects, and the timing and method of financing thereof;
- projections of market prices and costs;
- supply, demand and pricing for crude oil, natural gas, and CO_2;
- expectations regarding the Company's ability to raise capital and to continually add to reserves through acquisitions and development
- drilling inventory, drilling plans and timing of drilling, re-completion and tie-in of wells;
- plans for production facilities construction and completion and the timing and method of funding thereof;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production;
- drilling, completion and facilities costs;
- results of various projects of the Company;
- timing of receipt of regulatory approvals;
- timing and effect of production increases and the related effect and timing on operating costs per BOE;
- ability to lower cost structure in certain projects of the Company;
- growth expectations within the Company;
- timing of development of undeveloped reserves;
- the tax horizon and tax related implications of the Company;
- supply and demand for oil, natural gas liquids and natural gas;
- the performance and characteristics of the Company's oil and natural gas properties;
- the Company's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- the impact of federal and state governmental regulation on the Company, either directly or relative to other oil and gas issuers of similar size;

- realization of the anticipated benefits of acquisitions and dispositions;
- weighting of production between different commodities;
- expected levels of royalty rates, production and workover costs, office field expenses, general and administrative costs, costs of services and other costs and expenses; and
- benefits or costs related to settlement of financial instruments
- treatment under government regulation and taxation, including carbon taxation regimes

Although the Company believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. The Company cannot guarantee future results, levels of activity, performance, or achievements. Moreover, neither the Company nor any other person assumes responsibility for the outcome of the forward-looking statements. Many of the risks and other factors are beyond the Company's control, which could cause actual results to differ materially from those anticipated in these forward-looking statements as a result of risk factors as set forth, but not limited to, those below and elsewhere in this MD&A:

- volatility in market prices for oil, natural gas, and CO_2;
- liabilities and risks inherent in oil and natural gas operations;
- uncertainties associated with estimating reserves;
- competition for capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- incorrect assessments of the recoverability of asset costs and investments;
- geological, technical, drilling and processing problems; and
- governmental, regulatory and taxation regimes.

ABBREVIATIONS AND DEFINITIONS

Crude Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
BBls/d	barrels per day
BOEPD	barrel of oil equivalent per day
MMbbls	million barrels
Mbbls	thousand barrels

Carbon Dioxide and Natural Gas

Bcf	billion cubic feet
CO_2	carbon dioxide
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
Tcf	trillion cubic feet

API	American Petroleum Institute
Boe	Barrel of oil equivalent of natural gas and crude oil on the basis of one boe for six mcf of natural gas and one boe for forty- two gallons of plant products (these conversion factor are an industry accepted norm and is not based on either energy content or current prices).
Contingent resource	Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.
DD&A	Depreciation, depletion and amortization
DOE	United States Department of Energy

EBITDA	Income before income taxes, depletion, depreciation, amortization and accretion and often referred to as 'cash flow from operations'
EOR	Enhanced oil recovery, typically any method of economically removing oil incremental to that produced by primary or conventional improved-recovery methods.
MBoe	1,000 barrels of oil equivalent
Net revenue	Gross revenue less all taxes, royalties and lease operating expenses.
NI 51-101	National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* adopted by the Canadian Securities Administrators.
Permian Basin	A large crude oil and natural gas producing area representing a sedimentary basin dating from the Permian geologic period and covering an area extending from West Texas to eastern New Mexico.
Reserves	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 (i) analysis of drilling, geophysical and engineering data; (ii) the use of established technology; (iii) specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and (iv) a remaining reserve life of 50 years. These definitions and disclosures are in accordance with the definitions, procedures and standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook and the Canadian Securities Administrators NI 51-101.
Primary recovery	Production in which only existing natural energy sources in the reservoir provide for movement of well fluids.
Secondary recovery	Any method by which an essentially depleted reservoir is restored to producing status by the injection of liquids or gases (from external sources) into the formation, thereby effecting a restoration of reservoir energy which moves the unrecoverable secondary reserves through the reservoir to the wellbore.
Tertiary recovery	Any of various methods, chiefly reservoir drive mechanisms and enhanced recover techniques, designed to improve the flow of hydrocarbons from the reservoir to the wellbore to recover more oil after the primary and secondary methods (water and gas floods) are uneconomic.
$	United States dollars
C$	Canadian dollars