Hunter Oil Corp.

(formerly known as Enhanced Oil Resources Inc.)

Amended and Restated

Management's Discussion & Analysis

Six Months Ended June 30, 2017

DATE AND BASIS OF INFORMATION

Hunter Oil Corp., formally known as Enhanced Oil Resources Inc., is a corporation 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 are 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 Canada. 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."

Liquidity and Going Concern

While the unaudited interim condensed 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 the consolidated financial statements, certain conditions and events cast significant doubt on the validity of this assumption. For the three months ended June 30, 2017, the Company had negative cash flows from operations of approximately $0.3 million and, at June 30, 2017, an accumulated deficit of approximately $112.2 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.

The annual consolidated financial statements do not reflect the adjustments to the carrying values of assets and liabilities and the reported expenses and balance sheet classifications that would be necessary were the going concern assumption deemed to be inappropriate. These adjustments could be material.

Basis of Presentation

The following Management's Discussion and Analysis ("MD&A") is dated August 28, 2017 and should be read in conjunction with the Company's consolidated financial statements and related notes for the six months ended June 30, 2017, as well as the consolidated financial statements and related notes, and MD&A for the year ended December 31, 2016. 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 Six Months Ended June 30, 2017

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 Company's net proved reserves at December 31, 2016 and 2015, respectively, were 12.6 million and 6.2 million barrels of 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 June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Revenues				
Oil and gas sales	$ 347	$ 317	$ 804	$ 553
Less royalties	(72)	(66)	(168)	(117)
Revenues, net of royalties	275	251	636	436
Expenses				
Operating and production costs	241	180	560	348
Workover expenses	8	20	49	41
General and administrative	443	482	1,043	1,167
Loss on disposition of assets	-	45	22	45
Depreciation and depletion	144	172	324	363
Accretion	110	95	221	191
Other, net	(9)	(54)	24	4
Foreign currency translation loss	1	1	1	-
Total expenses	938	941	2,244	2,159
Net comprehensive loss for the period	$ (663)	$ (690)	$ (1,608)	$ (1,723)
Loss per share - basic and diluted	$ (0.08)	$ (0.12)	$ (0.20)	$ (0.30)

Results of operations for the six months ended June 30, 2017, included crude oil and natural gas sales revenues of $0.8 million, and a net loss of $1.6 million, compared to revenues of $0.6 million and a net loss of $1.7 million for the six months ended June 30, 2016. Per share losses (basic and fully diluted) were $0.20 and $0.30 for the six months ended June 30, 2017 and 2016, respectively. Cash used in operating activities for the six months ended June 30, 2017 was $0.3 million compared to $1.5 million in 2016, a decrease of $1.2 million.

Results of operations for both the three months ended June 30, 2017 and 2016, included crude oil and natural gas sales revenues of $0.35 million, and a net loss of $0.7 million. Per share losses (basic and fully-diluted) were $0.08 and $0.12 for the three months ended June 30, 2017 and 2016, respectively.

DISCUSSION OF OPERATIONS

Revenues

Gross sales of crude oil and natural gas in the first six months of 2017 increased $0.2 million, or 45.4 %, when compared to the same period in 2016. The increase is due to a 32.9% increase in the average price received for commodity sales ($44.77 per Boe in 2017 compared to $33.68 per Boe during the same three months in the prior year) coupled with a 9.4% increase in sales volumes (17,953 Boe's in 2017 compared to 16,414 Boe's in the prior year).

Gross sales revenue of crude oil and natural gas in the second quarter of 2017 increased 9.5% to $0.35 million when compared to 2016. The increase in revenue is due to a 0.3% increase in sales volumes (8,060 Boe's in 2017 compared to 8,036 Boe's in the prior year) coupled with a 7.7% increase in the average price received for commodity sales ($43.02 per Boe in 2017 compared to $39.96 per Boe during the same three months in the prior year).

Operating Costs, Production Costs and Netback

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 six months ended June 30, 2017, increased approximately $0.21 million (or 60.9%) to $0.56 million, compared to $0.35 million for 2016. The increase in costs is primarily due to the activity of eight wells that were acquired during 2016 and brought online coupled with the reactivation of wells in both the Milnesand and the Chaveroo fields.

Operating and production costs for the three months ended June 30, 2017, increased $0.06 million (or 33.9%) to $0.24 million when compared to the same three months in 2016. 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 during the first six months in 2017 increased $0.01 million (or 19.5%) to $0.05 million when compared to the prior year.

Workover expenses for the three months ended June 30, 2017, decreased $0.01 million (or 60.0%) to $0.08 million when compared to the same three months in 2016.

Netback: Operating netback for the six months ended June 30, 2017, increased $2.05 (or 113.9%) to $3.85 income per Boe when compared to 2016. The increase in income is primarily due to higher sales volumes and higher oil prices.

Operating netback for the quarter ending June 31, 2017, was $7.25 income per Boe compared to $3.74 income per Boe for the same period in 2016. The increase in income is primarily due increased sales volumes, higher average price received for commodity sales and lower workover costs during the period.

General and Administrative

General and administrative expenses decreased approximately $0.12 million (or 10.6%) to $1.0 million for the six months ended June 30, 2017. The decrease in expenses is primarily due to personnel reductions in the Houston office. General and administrative expenses for the quarters ended June 30, 2017 and 2016, were $0.4 million and $0.5 million, respectively.

Depreciation and Depletion

Depreciation and depletion expenses for the six months ended June 30, 2017, were $0.3 million compared to $0.4 million for the same period in 2016. The $0.1 million decrease was 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 expenses were $0.1 million and $0.2 million for the quarters ended June 30, 2017 and 2016, respectively.

Accretion

Accretion expense for both the six-month and the three-month periods ended June 30, 2017 and 2016, were $0.2 million and $0.1 million, respectively.

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 $0.75 for both of the six month periods ended June 30, 2017 and 2016.

EBITDA Reconciliation

(In thousands of US Dollars)	**Three Months Ended June 30,**		**Six Months Ended June 30,**	
	2017	**2016**	**2017**	**2016**
Net comprehensive loss	$ (663)	$ (690)	$ (1,608)	$ (1,723)
Adjustments:				
Loss on disposition of assets	-	45	22	45
Depreciation and depletion	144	172	324	363
Accretion	110	95	221	191
Foreign currency translation loss	1	1	1	-
Financing costs and other, net	(9)	(54)	24	4
EBITDA	**$ (417)**	**$ (431)**	**$ (1,016)**	**$ (1,120)**

Operating Netback Analysis

Operating Netback Per Gross Boe:

(In US dollars)		Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Oil & Gas Sales Volumes					
Oil equivalent	*Boe's*	8,060	8,036	17,953	16,414
Average prices [1]					
Oil equivalent	*$/Boe*	$ 43.02	$ 39.96	$ 44.77	$ 33.68
Less:					
Royalties, net [2]	*$/Boe*	(8.93)	(8.27)	(9.36)	(7.09)
Production taxes	*$/Boe*	(2.80)	(2.82)	(2.91)	(2.34)
Production costs	*$/Boe*	(23.09)	(24.81)	(24.84)	(22.30)
Workover expense	*$/Boe*	(0.95)	(0.32)	(3.81)	(0.15)
Operating Netback [3]	*$/ Boe*	$ 7.25	$ 3.74	$ 3.85	$ 1.80

[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.

LIQUIDITY AND CAPITAL RESOURCES

As of June 30, 2017, the Company had unrestricted cash of $0.2 million and restricted cash balances 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 2016, the Company received private placement proceeds of $1.75 million. Total gross proceeds received from the private placement was $2.5 million.

In order to provide the necessary funds to develop its projects, the Company is considering all available sources of financing to develop its projects, 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 the validity of this assumption. For the six months ended June 30, 2017, the Company had negative cash flows from operations of approximately $0.3 million and, at June 30, 2017, an accumulated deficit of approximately $112.2 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				2017	
	Third	Fourth	First	Second	Third	Fourth	First	Second
Revenues	$ 372	$ 325	$ 236	$ 317	$ 407	$ 455	$ 457	$ 347
Net comprehensive loss	$ (1,099)	$ (1,424)	$ (1,033)	$ (690)	$ (1,147)	$ (1,101)	$ (945)	$ (663)
Per share - basic	$ (0.69)	$ (0.89)	$ (0.65)	$ (0.12)	$ (0.20)	$ (0.19)	$ (0.12)	$ (0.08)
Per share - diluted	$ (0.69)	$ (0.89)	$ (0.65)	$ (0.12)	$ (0.20)	$ (0.19)	$ (0.12)	$ (0.08)

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				2017	
	Third	Fourth	First	Second	Third	Fourth	First	Second
Average price received	$ 43.34	$ 37.43	$ 28.19	$ 39.96	$ 39.58	$ 43.77	$ 46.19	$ 43.02
Sales volume	8,571	8,704	8,378	8,036	10,309	10,389	9,893	8,060

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. Crude oil sales decreased in the first and second quarters of 2017 principally due to the loss of production of a few wells that went offline during the period.

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 during 2016 coupled with the reactivation of wells in both the Milnesand and the Chaveroo fields. 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 fourth quarter of 2015 was due to the reactivation of numerous wells in both the Milnesand and the Chaveroo fields.

Revenue decreased in the second quarter of 2017 due to both the lost production of wells going offline and lower oil prices. 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 fourth quarter of 2015 due to lower commodity prices received from oil sales.

Equity Placements

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 2016, the Company received private placement proceeds of $1.75 million. Total gross proceeds received from the private placement was $2.5 million.

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 six months ended June 30, 2017.

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

The Company paid approximately $0.12 million in management fees to an entity controlled by the Company's Chief Executive Officer during the six months ended June 30, 2017 and 2016, respectively.

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:

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 judgment 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. In accordance with IFRS 15, the Company recognizes revenue when it satisfies a performance obligation (when control of the commodities is transferred to the purchaser). 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.

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). The consolidated annual financial statements have now been filed and the Company has applied for a revocation of the Cease Trade Order.

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 29, 2017:

1,000 preference shares (held by a wholly-owned subsidiary of the Company)
8,070,871 common shares

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.
Primary recovery	Production in which only existing natural energy sources in the reservoir provide for movement of well fluids.
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.
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