WESCAN ENERGY CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the consolidated financial condition and results of operations of WesCan Energy Corp. ("WesCan" or the "Company") dated February 27, 2019, which includes its subsidiaries, is for the three and nine months ended December 31, 2018. For a full understanding of the financial condition and results of operations of the Company, the MD&A should be read in conjunction with the Company's audited consolidated financial statements at March 31, 2018 together with the documents filed on SEDAR, including historical financial statements and MD&A. These documents are available at www.sedar.com.

DESCRIPTION OF BUSINESS

WesCan is an evolving exploration and production company with a key objective of providing its shareholders with attractive, long term sustainability by developing and exploiting the Company's assets at east-central, Alberta in a financially disciplined manner and by acquiring and consolidating additional oil and gas assets that are analogous to its infrastructure and focus area(s). WesCan's assets are comprised of 100% operated, oil-weighted properties characterized by multi-zone oil reservoirs with low declines that include a number of low risk, multi-lateral horizontal development drilling locations. WesCan continues to pursue and evaluate strategic acquisitions with synergistic characteristics of long life producing assets and opportunities with low risk, upside potential.

RESULTS OF OPERATIONS

PRODUCTION

	Three months ended December 31			**Nine months ended December 31**		
	2018	2017	**% Change**	2018	2017	**% Change**
Total BOE	12,180	10,653	14	36,136	30,397	19
Oil & NGL (BBL/D)	92	93	(1)	96	82	17
Natural Gas (MCF/D)	240	134	79	210	143	47
Total (BOE/D)	132	116	14	131	111	18
Oil & NGL % of Production	72%	80%		73%	74%	

Oil and NGL production increased 17% from 82 BBL/D in the nine months ended December 31, 2017 to 96 BBL/D in the nine months ended December 31, 2018. Mechanical failures of three wells in Q1 and Q2 resulted in a workover program which subsequently resumed production in the later part of Q2. Associated natural gas production increased 47% from 143 MCF/D in 2017 to 210 MCF/D in 2018. Oil and NGL production as a percentage of total production was 73%. During Q3, crude oil production dropped from 91 BOPD in October to 69 BOPD in December due to marketing apportionments resulting from pipeline restrictions due to "air barrel" deliveries in Alberta.

PRICES

	Nine months ended December 31		
	2018	2017	% Change
Average Benchmark Prices:			
WTI crude oil (US$/BBL)	65.00	50.90	28
US$/CDN$ exchange rate	0.77	0.77	-
Bow River crude oil (CDN$/BBL)	54.00	50.95	6
AECO daily spot (CDN$/ MMBTU)	1.55	2.40	(35)
Average Realized Prices:			
Light and medium oil ($/BBL)	52.44	51.74	1
Natural gas ($/MCF)	1.36	1.97	(31)
Average price ($/BOE)	40.51	42.77	(5)

WTI crude oil traded up 28% from an average price of $50.90 (US$/BBL) during 2017 to an average price of $65.00 ($US/BBL) during 2018. Bow River crude oil traded up 6% from an average price of $50.95 ($CDN/BBL) during 2017 to an average price of $54.00 ($CDN/BBL) during 2018. The average price for AECO natural gas decreased 35% from $2.40/MCF during 2017 to $1.55/MCF during 2018. The crude oil pricing environment is extremely volatile and subject to economic factors, both global and domestic, that are beyond the control of the Company. Such economic factors affecting WTI pricing include, US$/CDN$ exchange rates and oil differentials.

REVENUE

	Three months ended December 31			Nine months ended December 31		
	2018	2017	% Change	2018	2017	% Change
Oil & NGL Sales ($)	244,324	477,470	(49)	1,385,492	1,222,497	12
Natural Gas Sales ($)	39,484	24,210	63	78,394	77,690	1
Oil & Natural Gas Sales ($)	283,808	501,680	(43)	1,463,886	1,300,187	13

Production of crude oil increased 17% for the nine months ended December 31, 2018 as compared to the same period in 2017. With the average realized price showing no material increase year-over-year, this resulted in a 12% increase in oil and NGL sales. The production of associated natural gas increased 47% to 210 MCF/D in 2018 from 143 MCF/D in 2017, however, the realized price decreased 31% from $1.97 in 2017 to $1.36 in 2018. As a result, natural gas sales showed no real increase year over year.

ROYALTIES

	Three months ended December 31			Nine months ended December 31		
($ except BOE)	2018	2017	% Chang	2018	2017	% Change
Crown Royalties	4,823	1,965	145	10,375	11,388	(9)
Freehold Royalties	32,958	45,508	(28)	135,634	123,434	10
Royalty Expense	37,781	47,473	(20)	146,009	134,822	8
Royalty Expense as a % of Sales	13%	9%		10%	10%	
Royalty Expense per BOE	3.10	4.46		4.04	4.44	

There was an 8% increase in total royalty expense from $134,822 in the nine months ended December 31, 2017 to $146,009 for the same period in 2018. Increased production volumes over the nine month period in 2018 from the same period in 2017 substantiated the increase. Royalties as a percentage of revenues remain low at 10% in 2017.

OPERATING EXPENSE

	Three months ended December 31			Nine months ended December 31		
($ except BOE)	2018	2017	% Change	2018	2017	% Change
Operating costs	358,329	318,490	13	929,543	746,449	25
Operating costs as a % of Sales	126%	63%		63%	57%	
Operating costs per BOE	29.42	29.90		25.72	24.56	

IFRS rules require that the cost to re-enter or workover existing wells are to be expensed and not capitalized into property plant and equipment. During the nine months ended December 31, 2018 the Company expended $253,673 working over three wells on its core property. These additional expenses resulted in the total operating costs as a percentage of revenues increasing to 63%.

During Q3 crude oil production dropped from 91 BBL/D in October to 69 BBL/D in December largely due to the apportionment coming out of pipeline restrictions from "air barrel" deliveries in Alberta.

GENERAL AND ADMINISTRATIVE EXPENSE ("G&A")

	Three months ended December 31			Nine months ended December 31		
($ except BOE)	2018	2017	**% Change**	2018	2017	**% Change**
Gross G&A	99,525	139,915	(29)	359,379	398,402	(10)
Capitalized G&A	-	-	-	-	-	-
Net G&A expense	99,525	139,915	(29)	359,379	398,402	(10)
Net G&A expense per BOE	8.17	13.42		9.94	13.11	

Overhead efficiencies resulted in a 10% reduction in G&A expenses from 2017 to 2018. The Company does not capitalize any G&A expenses.

INTEREST AND FINANCE EXPENSE

Interest expense is generated entirely by the interest payable on the convertible loans outstanding. The Company has no bank debt.

NETBACKS

	Three months ended December 31			Nine months ended December 31		
($ / BOE)	2018	2017	**% Change**	2018	2017	**% Change**
Oil and Natural Gas Sales	23.30	47.09	(51)	40.51	42.77	(5)
Royalties	3.10	4.46	(30)	4.04	4.44	(9)
Operating costs	29.42	29.90	(2)	25.72	24.56	5
Operating Netback	(9.22)	12.73	(172)	10.75	13.78	(22)

Operating netbacks per BOE decreased 22% from $13.78/BOE in 2017 to $10.75/BOE in 2018. The continued weakness and market volatility in the price of oil and natural gas together with the increase in operating costs, contributed significantly to the decline. During Q3, crude oil production dropped from 91 BBL/D in October to 69 BBL/D in December largely due to the apportionment coming out of pipeline restrictions from “air barrel” deliveries in Alberta.

DEPLETION, DEPRECIATION AND ACCRETION

	Three months ended December 31			Nine months ended December 31		
($ except BOE)	2018	2017	% Change	2018	2017	% Chang
Depletion	93,188	120,000		348,636	361,000	
Depreciation		21,837		42,452	66,026	
Accretion	8,200	8,000		24,600	24,000	
DD&A	101,388	149,837	(32)	415,688	451,026	(8)
DD&A per BOE	8.32	14.06		11.50		

IMPAIRMENT

Impairment is recognized when the carrying value of an asset or group of assets exceeds its recoverable amount, defined as the higher of its value in use or fair value less costs of disposal. Any asset impairment that is recorded is recoverable to its original value less any associated DD&A expense should there be indicators that the recoverable amount of the asset has increased in value since the time of recording the initial impairment.

As at December 31, 2018, the Company evaluated its developed and producing ("D&P") assets and exploration and evaluation ("E&E") assets on a Cash Generating Unit basis for indicators of any potential impairment or related recovery. As a result of this assessment, no indicators were identified and no impairment or related reversal was recorded on the Company's D&P assets and E&E assets for the nine months ended December 31, 2018.

FUNDS FROM OPERATIONS

	Three months ended December 31		Nine months ended December 31	
($ except per share amount)	2018	2017	2018	2017
Cash flow from (used in) operating activities	(43,904)	107,095	125,789	121,082
Changes in non-cash working capital	(167,922)	(111,293)	(96,834)	(100,514)
Funds from operations	(211,826)	(4,198)	28,955	20,514
Per share - basic / diluted	(0.01)	(0.00)	(0.00)	(0.00)

CAPITAL EXPENDITURES

	Three months ended December 31			Nine months ended December 31		
	2018	2017	% Change	2018	2017	% Change
Acquisition of oil and gas assets	-	-		-	-	
Expenditures on E&E assets	-	-		-	-	
Total capital expenditures	-	-		-	-	

The Company did not incur any capital expenditures during the first nine months of 2018 or 2017.

DECOMMISSIONING LIABILITIES

($)	December 31 2018	March 31 2018
Balance, beginning of the year	1,579,962	1,472,536
Accretion	24,600	32,000
Change in estimates		75,426
Balance, end of year	1,604,562	1,579,962
Less: current portion	(60,448)	(60,448)
Long-term portion	1,544,114	1,519,514

CAPITAL RESOURCES AND LIQUIDITY

WesCan's major source of liquidity has been the issuance of equity capital. The Company obtains equity capital financings from private placement offerings of shares and share purchase warrants and the exercise of share purchase warrants and stock options. The Company conducts private placement equity financings from time-to-time, based on cash flow needs and subject to investor interest.

In order to continue as a going concern and meet the Company commitments and current obligations, the Company will require additional equity financing(s) during the next twelve months. At December 31, 2018, the Company's working capital deficiency was $1,009,236 (March 31, 2018 - $1,449,767).

On March 8, 2018, the Company completed a non-brokered private placement, issuing 6,666,667 units at $0.075 per unit for total proceeds of $500,000. Each unit is comprised of one common share and one common share purchase warrant. Each warrant will entitle the holder to purchase one common share for a period of 24 months from the closing date at an exercise price of $0.10 per share.

Additional equity financing(s) will be required in order to carry out the exploration and development necessary to achieve a self-sustaining level of production, revenue, cashflow and to further achieve our oil and gas business objectives. There is no assurance that the Company will be successful in obtaining any such financing.

The Company has traditionally supplemented equity financings from time to time by obtaining loans from third parties. These loans were used to provide interim, short-term financings to meet day-to-day cashflow requirements and are not intended to be a long-term source of capital. At December 31, 2018, the Company has convertible loans owing to unrelated parties in the amount of $768,460, including accrued interest. These loans are due on demand and bear interest of up to 10% per annum. They are unsecured and have no fixed re-payment terms and convertible into equity at the option of both the Company and its Lenders. As a result, the Company is unable to estimate the allocation of value between the debt and the equity component, therefore, no value is ascribed to the equity component on the convertible aspect of these loans.

Our ability to obtain financing is sensitive to economic factors beyond the control of management. Declines in the Canadian dollar, commodities prices, changes in interest rates and the continued economic concerns or disruptions could significantly affect our ability to obtain adequate financing.

The Company had no long-term debt or long-term financial liabilities outstanding at December 31, 2018.

SUMMARY OF QUARTERLY INFORMATION

	2019			2018				2017
Quarters ended	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
OPERATING								
Average daily production								
Oil & NGL (BBL/D)	92	103	83	101	93	93	80	98
Natural gas ((MCF/D)	240	206	151	167	134	157	81	105
Total BOE (BOE/D)	132	137	108	129	116	119	94	115
Average sales price								
Oil ($/BBL)	52.44	63.47	49.54	47.95	51.74	42.48	54.67	27.59
Natural gas ($/MCF)	1.36	1.20	2.47	2.42	1.97	1.97	2.50	1.45
Total ($/BOE)	40.51	48.97	41.44	40.74	42.77	35.39	55.50	24.72
Operating netback ($/BOE)								
Oil & gas sales	23.30	65.18	41.44	40.74	47.09	35.39	55.50	24.72
Royalty expense	3.10	4.86	4.53	4.54	4.46	4.02	10.85	2.45
Operating expense	29.42	27.57	19.76	26.35	29.90	16.45	30.06	28.84
Netback	(9.22)	32.75	17.15	9.85	12.73	14.92	14.59	(6.57)
FINANCIAL								
Oil & gas sales	283,801	595,355	406,929	420,482	501,680	387,599	192,601	262,264
Funds from operations	(211,826)	243,145	28,406	22,891	(4,198)	55,132	(55,791)	(174,331)
Per share - Basic/Diluted	(0.09)	0.01	0.00	0.00	(0.00)	0.00	(0.00)	(0.01)
Cash flow from (used in)	(43,904)	172,219	37,590	15,231	107,095	22,319	(31,090)	(118,017)
Per share – Basic/Diluted	(0.00)	(0.01)	0.00	0.00	0.00	0.00	(0.00)	(0.01)
Net Income (loss)	(312,854)	4,755	(130,512)	1,601,696	(181,117)	(123,539)	(48,509)	3,369,483
Per share – Basic/Duluted	(0.01)	0.00	(0.00)	0.07	(0.01)	(0.01)	(0.00)	0.15
Capital expenditures	-	-	-	-	-	-	-	-
Total Assets	7,017,901	7,301,612	7,429,229	7,581,508	7,195,265	6,332,349	6,477,227	6,689,063
Working capital (deficiency)	(1,009,236)	(804,269)	(1,685,834)	(1,696,776)	(2,241,224)	(2,303,102)	(1,858,769)	(2,331,342)
Shareholders' Equity	3,692,095	3,998,450	3,894,966	4,025,477	2,064,050	2,150,671	(779,609)	2,423,781
Shares Outstanding	31,359,658	31,359,658	31,359,658	21,753,991	21,753,991	21,753,991	21,753,991	21,753,991

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company's consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities and contingent liabilities at the date of the consolidated financial statements and reported amounts of revenues and expenses during the reporting year. Estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. However, actual outcomes can differ from these estimates.

Areas requiring a significant degree of estimation and judgment relate to the determination of the recoverability of the carrying value of exploration and evaluation assets, estimates of oil and natural gas reserves, fair value measurements for financial instruments and share-based payments and other equity-based payments, the recognition and valuation of provisions for restoration and environmental liabilities, provision for doubtful accounts, and the recoverability and measurement of deferred tax assets and liabilities. Actual results may differ from those estimates and judgments.

Management relies on the estimate of reserves as prepared by the Company's independent qualified reserves evaluator. The process of estimating reserves is critical to several accounting estimates. The process of estimating reserves is complex and requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development and production activities becomes available and as economic conditions impact crude oil and natural gas prices, operating expense, royalty burden changes, and future development costs charges. Reserve estimates impact net income through depreciation and impairment of petroleum and natural gas properties. Revision or changes in the reserve estimates can have either a positive or a negative impact on net income of the Company.

RESERVES ESTIMATES

Commercial petroleum reserves are determined based on estimates of petroleum-in-place, recovery factors and future oil and natural gas prices and costs. WesCan engages an independent qualified reserve evaluator to evaluate all of the Company's oil and natural gas reserves at each year-end.

Reserve adjustments are made annually based on actual oil and natural gas volumes produced, the results from capital programs, revisions to previous estimates, new discoveries and acquisitions and dispositions made during the year and the effect of changes in forecast future crude oil and natural gas prices. There are a number of estimates and assumptions that affect the process of evaluating reserves.

Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids determined to be economically recoverable under existing economic and operating conditions with a high degree of certainty (at least 90 percent) those quantities will be exceeded. Proved plus probable reserves are the estimated quantities of crude oil, natural gas and natural gas liquids determined to be economically recoverable under existing economic and operating conditions with a 50 percent certainty those quantities will be exceeded. WesCan reports production and reserve quantities in accordance with

Canadian practices and specifically in accordance with “Standards of Disclosure for Oil and Gas Activities” (“NI 51-101”).

The estimate of proved plus probable reserves is an essential part of the depletion calculation, the impairment test and hence the recorded amount of oil and gas assets. WesCan cautions users of this information that the process of estimating crude oil and natural gas reserves is subject to a level of uncertainty. The reserves are based on current and forecast economic and operating conditions therefore, changes can be made to future assessments as a result of a number of factors, which can include commodity prices, new technology, changing economic conditions, and future reservoir performance and forecast development activity.

Recoverability of Asset Carrying Values

WesCan assesses its property, plant and equipment (“PP&E”) for impairment by comparing the carrying amount to the recoverable amount of the underlying assets. The determination of the recoverable amount involves estimating the higher of an asset’s fair value less costs to sell or its value-in-use, the latter of which is based on its discounted future cash flows using an applicable discount rate. Future cash flows are calculated based on estimates of future commodity prices and inflation and are discounted based on Management’s current assessment of market conditions.

Recoverability of Exploration and Evaluation Assets

Exploration and evaluation (“E&E”) assets are assessed for impairment by comparing the carrying amount to the recoverable amount. The assessment of the recoverable amount involves a number of assumptions, including the timing, likelihood and amount of commercial production, further resource assessment plans, and future revenue and costs expected from the asset, if any.

DECOMMISSIONING LIABILITIES

Decommissioning liabilities are the present value of management's estimate of future costs to be incurred to properly abandon and reclaim the Company's properties. Accretion expense is the increase in the decommissioning liabilities resulting from the passage of time. Decommissioning liabilities increased to $1,604,562 as at December 31, 2018 from $1,579,962 as at March 31, 2018.

ASSET RETIREMENT OBLIGATIONS

WesCan recognizes a provision for future abandonment activities in the consolidated financial statements at the net present value, discounted at the risk-free rate, of the estimated future expenditures required to settle the estimated obligation at the balance sheet date. The measurement of the asset retirement obligation (“ARO”) involves the use of estimates and assumptions including the discount rate, the amount and expected timing of future abandonment costs and the inflation rate related thereto. The estimates were made by Management considering current costs, technology and enacted legislation.

FINANCIAL INSTRUMENT RISK

Significant sources of financial instrument risk are detailed as follows:

Interest Rate Risk

Interest rates applicable on the loans payable are fixed and accordingly are not subject to interest rate volatility during the year.

Currency Risk

The Company currently generates revenue from a natural gas well in the USA. Changes in the U.S. denominated value of the Canadian dollar could not impact the Canadian dollar cost of meeting any future obligations under that prospect and will affect the Canadian dollar-denominated value of natural gas production.

The Company is exposed to foreign currency risk on its U.S dollar denominated assets and financial liabilities. At December 31, 2018 the Canadian dollar cost of paying the Company's US dollar denominated liabilities and property payment commitments would have no material impact with a 1% increase in the value of the US dollar relative to the Canadian dollar.

Commodity Price Risk

The Company is exposed to material oil and gas commodity price risks. A relative decrease in the price of oil and gas would reduce the Company's cashflows, reduce the realizable market value of the Company's oil and gas assets, reduce the Company's economic reserves, and make it more difficult for the Company to raise the equity capital required to meet its commitments and carry out its development-stage business plans. The Company sells its production on the spot market. Management has assessed that the Company's degree of exposure to commodity price risk is material, however, it remains consistent with our development-stage oil and gas operations.

Liquidity Risk

The Company faces material liquidity risk in that it has $952,784 in payables to trade and to un-related parties at December 31, 2018 and insufficient cash on hand to satisfy those debts should they be demanded. The Company is seeking equity financing(s) in order to obtain additional liquidity to mitigate and resolve this risk.

OUTLOOK

Management continues to focus its attention on the future development and exploitation of our core property and is confident that the underlying reserves will capture the future growth potential of the property. With the on-going focus of identifying low cost optimization projects and the re-activation of shut-in wells, such efforts will continue to increase the Company's cashflow while providing attractive payouts and return on capital.

In addition, Management is currently reviewing the geological and reservoir engineering evaluations for a number of new development drilling opportunities that exist on the Company's property. While the Company continues to further examine the overall potential of the project, management remains perceptive and vigilant of the international markets and the domestic commodity pricing environment. Such influences continue to be prudently reviewed and evaluated prior to any significant capital expenditure with the objective of preserving our reserves and obtaining more favorable pricing for our resources.