PetroFrontier

Management's Discussion & Analysis

December 31, 2018

PetroFrontier Corp. (the “Corporation”) is a public company, which is engaged in the business of exploring and developing petroleum and natural gas properties in western Canada. The Corporation has a fiscal year end of December 31.

This Management’s Discussion & Analysis (“MD&A”) is a review of how the Corporation performed during the period covered by the consolidated financial statements, and of the Corporation's financial condition and future prospects. The MD&A complements and supplements the consolidated financial statements of the Corporation and should be read in conjunction with the Corporation’s consolidated financial statements and the related notes for the years ended December 31, 2018 and 2017. The financial statements have been prepared in Canadian dollars in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (“IASB”) and interpretations of the International Financial Reporting Interpretations Committee (“IFRIC”), which are also generally accepted accounting principles (“GAAP”) for publicly accountable enterprises in Canada.

The Corporation's Board of Directors has reviewed and approved the consolidated financial statements and MD&A, both of which are effective April 24, 2019.

Forward-Looking Statements

Certain statements contained in this document, including Management’s assessment of the Corporation’s future plans and operations, may constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "plan" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Corporation, or industry results, to differ materially from those expressed or implied by such forward-looking statements. The Corporation believes the expectations reflected in these forward- looking statements are based on reasonable assumptions but no assurance can be given that these expectations will prove to be correct and the forward-looking statements included in this document should not be unduly relied upon. These statements speak only as of the date of this document.

Non-IFRS Measures

The financial data presented herein has been prepared in accordance with IFRS. The Corporation has also used certain measures of financial reporting that are commonly used as benchmarks within the oil and natural gas production industry in the following MD&A discussion. The measures are widely accepted measures of performance and value within the industry and are used by investors and analysts to compare and evaluate oil and natural gas exploration and producing entities. Most notably, is “operating netback”. Operating netback is a benchmark used in the crude oil and natural gas industry to measure the contribution of oil and natural gas sales and is calculated by deducting royalties and operating expenses but adding back lease rentals from non-producing properties from revenues on a dollar basis divided by total production for the period on a boe or bbl basis. This measure is not defined under IFRS and should not be considered in isolation or as an alternative to conventional IFRS measures. This measure and its underlying calculations are not necessarily comparable or calculated in an identical manner to a similarly titled measure of another entity. When this measure is used, it is defined as “non IFRS” and should be given careful consideration by the reader.

Other terms used in this report are as follows:

bbl – barrel
bbls/d – barrels per day
CHOPS – Cold heavy oil produced with sand
WTI – West Texas Intermediate (a light oil reference price)
WCS – Western Canadian Select (a heavy oil reference price)

Corporate Overview

The Corporation is engaged in exploring for and the production of petroleum and natural gas in western Canada. The current core property is Cold Lake, a conventional heavy oil project.

The Corporation has two wholly-owned inactive Australian subsidiaries, PetroFrontier (Australia) Pty Ltd and Texalta (Australia) Pty Ltd (collectively "PetroFrontier (Australia)"). When used herein, the term "Corporation" includes PetroFrontier (Australia) on a consolidated basis.

The Corporation operates from its offices located at 900, 903 - 8 Avenue SW, Calgary, Alberta, T2P 0P7.

The common shares of the Corporation trade on the TSX Venture Exchange under the trading symbol "PFC".

Overview of Consolidated Financial Results

The following selected financial data is derived from the consolidated financial statements of the Corporation and reference should be made to such financial statements for the year ended and as at December 31:

		2018	**2017**		**2016**
Net loss	$	2,290,208	1,761,506	$	707,769
Net comprehensive loss		2,290,208	1,761,506		709,685
Per common share (basic and diluted)		0.02	0.01		0.01
Working capital (deficiency)		(5,641,812)	(3,814,066)		2,131,682
Total assets		20,191,205	21,692,634		22,695,432
Total long-term liabilities		3,398,018	3,549,422		5,832,030
Shareholders' equity	$	10,969,915	13,218,706	$	14,826,359

The Corporation's net loss for the fourth quarter of 2018 is discussed further in the section *"Discussion of Operations"* and the working capital deficiency is discussed under *"Liquidity and Capital Resources"*.

Outlook

While capital markets remain challenging for companies in the oil and gas sector, it is management's belief that the Corporation continue to focus on controlling its capital spending and costs while maintaining its considerable working interests in preparation for improved access to capital. Management continues to believe that shareholders will be best served over the long term if the Corporation effectively secures and prudently develops substantial working interests in sizeable contiguous land blocks within prospective play areas dominated by large companies. Management continues to take the necessary steps to preserve and enhance the Corporation's interests in a manner that allows for the development of its sizable drilling portfolio with a view to significantly increasing production when capital investment returns to the sector in order to realize upon the considerable value the Corporation has created. Management believes that prudently managing capital and costs coupled with its credit facilities (see *"Convertible note payable"*) and the continued support of its debenture holder will put PetroFrontier in a position to meet the on-going challenges being faced by the Corporation and the entire industry at this time.

Core properties

The Corporation has interests in approximately 18 gross (16.5 net) sections arising under several joint operations with the wholly-owned energy companies of the Cold Lake First Nations ("CLFN").

As at December 31, 2018, fourteen (14) wells have been drilled under the joint ventures establishing multi-zone productivity and substantial reserves. Two horizontal wells and one slant well were drilled in the first quarter of 2017 to establish additional reserves with respect to the Corporation's already substantial reserves base and to increase daily production. These three wells have performed within the expected range with the horizontal well results supporting management's view that horizontal development is the key to maximizing the potential of the asset base.

By virtue of a joint venture agreement with the wholly-owned energy company of the Bigstone Cree Nation ("BCN") dated May 7, 2018, the Corporation also has interests in approximately 1,216 gross hectares in the Wabasca area of north-central Alberta. The Corporation's interests are located between CNRL's prolific Brintnell field currently producing 63,000 bop/d of heavy oil and Husky's proposed 10,000 bop/d heavy oil project announced earlier this year.

Discussion of Operations

Revenue

2018	YTD	Q4	Q3	Q2	Q1
Revenue	$3,557,724	$275,430	$1,070,613	$1,283,113	$928,568
# bbls	94,770	17,894	18,849	27,497	30,530
Bbls/d	260	195	243	302	339
Revenue per bbl	$37.54	$15.39	$47.82	$46.66	$30.41
WCS -$C per bbl	$49.85	$25.62	$61.76	$62.75	$48.76
Differential to WCS	24.7%	25.0%	22.5%	25.6%	30.4%

2017	YTD	Q4	Q3	Q2	Q1
Revenue	$5,368,064	$1,125,481	$1,537,431	$1,351,105	$1,354,047
# bbls	136,307	28,334	38,815	34,631	34,527
Bbls/d	374	308	422	381	387
Revenue per bbl	$39.38	$39.72	$39.61	$39.01	$39.21
WCS -$C per bbl	$50.59	$54.86	$47.91	$49.96	$49.36
Differential to WSC	22.2%	27.6%	18.0%	21.9%	25.4%

The petroleum revenue for 2018 was $3,557,724 (2017 - $5,368,064) a decrease of $1,810,340 with production averaging 260 bbls/d (2017 – 374 bbls/d). The Corporation realized an average price of $37.54 per bbl for 2018 (2017 - $39.38) while the WCS benchmark price for heavy oil averaged C$49.85 (2017 – C$50.59). The decrease in revenue in 2018 as compared to 2017 is primarily attributable to a decrease of 41,537 of barrels sold.

The Corporation's realized sales price is lower than the WCS benchmark price as the Corporation sells lower gravity oil than that used in setting the WCS benchmark price.

Royalties

Royalty expense was $288,950 for 2018 and averaged 8.1% of petroleum revenue which is comparable to 2017 where royalties were 8.0% of petroleum revenue. Royalties are generally paid to Indian Oil and Gas Canada on behalf of the Cold Lake First Nation.

Production operating costs

Total production operating costs were $2,948,519 in 2018 compared to $3,254,505 in 2017, a decrease of $305,986. The decrease in 2018 costs is primarily related to the Corporation's on-going cost reduction efforts as well as a reduction in sand handling costs as no wells were drilled in 2018 as compared to 3 wells in 2017. In addition, with 2018 production being lower, petroleum transportation costs have decreased while the Corporation has still been able to achieve higher operating efficiencies while fixed operating costs are being spread over a reduced production base. The prominent production costs continue to be for sand handling, utilities and petroleum transportation.

General and administrative expense

The main components of the Corporation's general and administrative expenditures are as follows:

	Three months ended December 31		**Years ended December 31**	
	2018 ($)	**2017 ($)**	**2018 ($)**	**2017 ($)**
Salaries and benefits	192,894	312,506	862,406	1,045,538
Office costs	70,109	99,188	322,297	397,589
Professional fees	47,982	27,595	250,985	258,943
Corporate and regulatory	4,422	2,361	25,395	14,094
	315,407	**441,650**	**1,461,083**	**1,716,164**

Overall, the general and administrative expenses have decreased $255,081 year over year and $126,243 quarter over quarter. The decrease is primarily related salaries and wages where there was a reduction in head count and a salary rollback.

Depletion and depreciation

Depletion and depreciation were $739,505 for 2018 (2017 - $912,991). Depletion relates to the resource assets and is based on the unit-of-production method based on proven and probable reserves. The depletion expense per bbl in 2018 was $7.80 as compared to $6.69 in 2017.

Accretion on decommissioning liabilities

Accretion expense was $256,477 for 2018 (2017 - $239,953) and reflects the increase in the liability due to the passage of time.

Share-based compensation

Share-based compensation was $41,417 for 2018 (2017 - $153,853) and is based on the vesting of stock options.

Finance income and expense

Finance expense was $111,981 for 2018 as compared to $426,793 for the same period in 2017. The decrease relates to the accretion of the debenture which was fully accreted in 2017 and thus no accretion is recorded in 2018. The interest on the convertible note payable was $21,981 for 2018 as the first draw of $500,000 occurred on May 31, 2018.

Operating Netback

The following table details the Corporation's operating netback which is defined in a preceding section *"Non-IFRS Measures"*:

	Three months ended December 31, 2018		**Year ended December 31, 2018**	
		Per boe		**Per boe**
Production (boe)	17,894		94,770	
Average daily production (boe/d)	195		260	
Petroleum and natural gas revenue	$275,430	$15.39	$3,557,724	$37.54
Royalties	$29,991	$1.68	$288.950	$3.05
Production operating costs (1)	$608,243	$33.99	$2,660,115	$28.07
Operational netback (loss)	($362,804)	($20.28)	$608,659	$6.42

(1) excludes annual lease rentals of $74,458 and $288,404 for the three months and year ended December 31, 2018, respectively, related to non-producing lands

	Three months ended December 31, 2017		**Year ended December 31, 2017**	
		Per boe		**Per boe**
Production (boe)	28,334		136,307	
Average daily production (boe)	308		373	
Petroleum and natural gas revenue	$ 1,125,571	$ 39.72	$ 5,368,064	$ 39.38
Royalties	$ 83,813	$ 2.96	$ 431,649	$ 3.17
Production operating costs (2)	$ 665,665(1)	$ 23.49	$ 3,046,426(1)	$ 22.35
Operational netback	$ 376,093	$ 13.27	$ 1,889,989	$ 13.87

(1) excludes annual lease rentals of $76,873 and $208,079 for the three months and year-ended ended December 31, 2017, respectively, related to non-producing lands

The Corporation's operating netback was lower in the fourth quarter of 2018 when compared to the fourth quarter in 2017 as there was a significant increase in the production operating cost per barrel of oil of $19.06 This occurs from the fixed operating costs being spread over a lower production base. Production operating costs in 2018 and 2017 reflect the sand handling costs associated with the wells drilled in 2017 during the clean-up phase. Sand handling costs make up a major portion of the production operating costs of CHOPS wells. Initial production from CHOPS wells in the Cold Lake area may contain 50% or more sand during the clean-up phase (typically 6 - 12 months), whereas that sand cut typically drops to 10 – 20% following clean-up, resulting in lower operating costs.

The petroleum revenue for the heavy oil produced at Cold Lake is based on the WCS Benchmark price.

Details of quarterly pricing in 2018 and 2017 is as follows:

2018	Q4	Q3	Q2	Q1
WTI - $US/bbl	58.81	69.50	67.88	62.87
WCS Benchmark –US$/bbl	33.82	47.25	48.61	38.59
WCS Dollar Differential –US$/bbl	21.99	22.25	19.27	24.28
WCS % Differential	37%	32%	28%	39%

2017	Q4	Q3	Q2	Q1
WTI - $US/bbl	55.40	48.21	48.29	51.91
WCS Benchmark –US$/bbl	43.14	38.26	37.16	37.33
WCS Dollar Differential –US$/bbl	12.26	10.05	11.13	14.58
WCS % Differential	22%	21%	23%	28%

As with most energy companies today, an increase in crude oil prices will have a significant positive impact on bottom line operating results. Management is prepared to increase activity with a view to increasing production in a more favourable price environment, which would improve the netback given the effect of spreading fixed operating costs over a larger production base.

Quarterly results – Fourth quarter

The net loss in Q4 2018 was $976,151 as compared to Q3 2018 loss of $577,907. The increase in the loss in from the third quarter of $398,244 results primarily from a decrease in revenue.

The revenue in Q4 2018 was $275,430 as compared $1,070,613 in Q3 2018. The decrease in revenue reflects the negative revenue earned in November and December of $88,818 whereby the cost of the diluent exceeded the proceeds of the oil sales. The widening differential in the WCS to WTI price due to the difficulty in shipping oil due to pipeline constraints has been well documented.

The average realized sales price to the Corporation in Q4 was C$15.39 per bbl versus $47.82 per bbl in the Q3 2018.

Third quarter royalty expense of $86,929 was 32% of revenue and reflects the imbalance between the selling price of oil and the diluent costs.

Production operating costs in Q4 2018 were $682,702 compared to Q3 costs of $912,645. This decrease reflects increased costs to repair access roads, repairs and maintenance and sand removal costs partially due to wet weather in the third quarter.

General and administrative costs in Q4 2018 were $315,407 as compared to Q3 2018 expense of $349,331. The decrease of 33,924 is attributable to a decrease in professional and consulting fees in Q4 2018.

Depletion and depreciation expense was $125,471 for Q4 2018 as compared to $196,718 in Q3 2018. The depletion expense per bbl in Q4 2018 was $7.01 as compared to $7.14 in Q3 2018.

There was no share-based compensation expense in Q4 2018 as all share options became fully vested in the third quarter.

Cash

As at December 31, 2018, the Corporation had cash of $76,766 as compared to $221,461 as at December 31,

2017. The decrease in cash of $144,695 results primarily from cash used in operations of $344,570, capital expenditures of $516,670 offset by the proceeds of $500,000 from the issuance of the convertible note.

Trade and other receivables

The balance of trade and other receivables were $46,422 at December 31, 2018 as compared to $748,163 at December 31, 2017. The receivable balance is lower at December 31, 2018 as there were no oil sales in December or November that resulted in cash proceeds. In fact, the Corporation owed the marketer in those months as diluent costs exceeded the oil sales proceeds.

Prepaid Expenses and Deposits

Prepaid expenses and deposits at December 31, 2018 was $58,272 and is primarily comprised of prepaid industry fees.

Property and equipment

The Corporation did not drill any wells in 2018 thus capital expenditures were minimal in the year.

Exploration and evaluation assets

As discussed in the following section **"***Material Contracts, Commitments and Contingencies",* the Corporation entered into a Development Agreement at a cost of $250,000.

Trade and other payables

Trade and other payables at December 31, 2018 were $2,233,272 as compared to $1,924,506 at December 31, 2017. The trade and other payables reflect a slower payment schedule in order to manage liquidity.

Convertible note payable

On May 16, 2018, the Corporation finalized a credit facility with a corporation controlled by a director (the "Lender"), which provides for a credit facility not exceeding $1,500,000. The advances under the credit facility bear interest at 8% per annum payable monthly and are secured by a General Security Agreement with the minimum advance being $500,000. The Lender was also be paid a structuring fee equal to 2% of the amount of any advance under the credit facility, with a minimum structuring fee of $10,000 payable.

The Lender has the option to convert the advances under the credit facility into common shares of the Corporation ("Common Shares"). The conversion price per Common Share shall be: (i) $0.08 for the first year of the term of the loan; and (ii) $0.10 for the second year of the term of the loan.

The credit facility matures two years from the date of closing. In 2018, $500,000 was advanced under this credit facility and the $10,000 was paid as structuring fee. Further advances of $450,000 have been made to date in 2019 under this credit facility.

As at December 31, 2018 interest of $6,575 had not been paid as required under the terms of the convertible note payable. As a result of the non-payment of the interest, the principal amount of the debenture becomes a current liability. On April 17, 2019, the convertible note payable holder waived the requirement to pay interest until maturity including the arrears interest.

Debenture

	December 31, 2018 ($)	December 31, 2017 ($)
Balance, beginning of year	3,000,000	2,663,207
Accretion in the year	-	336,793
	3,000,000	3,000,000
Less: current portion	(3,000,000)	(3,000,000)
Balance, end of period	-	-

On July 21, 2016, the Corporation issued a 3% secured convertible debenture in the principal amount of $3,000,000 to Kasten Energy Inc. ("Kasten"). The debenture matures no later than June 30, 2019 and is secured against the property of the Corporation with interest payable monthly. The Corporation is currently discussing an extension to the maturity date of the debenture.

The Corporation may redeem the debenture prior to maturity by a cash payment.

As at December 31, 2018 interest of $157,500 (December 31, 2017 $67,500) had not been paid as required under the original terms of the debenture. On April 25, 2018, the debenture holder waived the requirement to pay interest until maturity including the arrears interest.

Decommissioning Liabilities

The Corporation's total decommissioning liability is estimated based on the Corporation's net ownership in wells and facilities and management's estimate of costs to abandon and reclaim those wells and facilities, as well as an estimate of the future timing of the costs to be incurred.

By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements could be significant. The total undiscounted amount of the estimated cash flows required to settle its decommissioning liabilities are approximately $5,017,254 (December 31, 2017 - $5,017,254) which will be settled over the operating lives of the underlying assets, estimated to occur primarily over the next ten years. A credit adjusted interest rate of 8% (2017 – 7%) and an inflation rate of 2% (2017 – 2%) were used to calculate the decommissioning liability. Settlement of the liability will be funded from general corporate funds at the time of retirement or removal.

Changes to the liabilities were as follows:

Decommissioning Liabilities	**December 31 2018 ($)**	**December 31 2017 ($)**
Balance, beginning of year	**3,549,422**	3,463,498
Liabilities incurred	**-**	41,128
Revisions to previously recorded liabilities	**(317,881)**	(195,157)
Accretion	**256,477**	239,953
	3,488,018	3,549,422
Current portion	**(90,000)**	-
Balance, end of year	**3,398,018**	3,549,422

Net Loss

The Corporation recorded a net loss in 2018 of 2018 of $2,290,208 as compared to a loss of $1,761,506 in 2017. The increase in the loss in 2018 as compared to 2017 results from a decrease oil prices and lower production volumes.

Common share information

Issued – common shares

	Year Ended December 31, 2018		**Year Ended December 31, 2017**	
	Number of shares	Amount ($)	Number of shares	Amount ($)
Common Shares				
Balance, beginning and end of period	149,600,768	131,202,046	149,600,768	131,202,046

At the date of this MD&A, there are 149,600,768 Common Shares outstanding.

Stock options

Officers and directors of the Corporation have been granted options to purchase common shares. Options granted have a term of five years to expiry and typically vest equally over a two-year period on the basis of 40% on the date of grant, 30% on the first anniversary date of the grant, and 30% on the second anniversary date of the grant. The exercise price of each option equals the market price or greater of the Corporation's common shares on the date of grant.

The following table summarizes the changes to the Corporation's option plan:

	Year ended December 31, 2018			**Year ended December 31, 2017**		
	#		Weighted average exercise price	#		Weighted average exercise price
Outstanding, beginning of year	**13,900,000**	**$**	**0.16**	13,900,000	$	0.16
Expired	**(1,100,000)**		**-**	-		-
Outstanding, end of year	**12,800,000**	**$**	**0.16**	13,900,000		13,900,000
Exercisable, end of period	**12,800,000**	**$**	**0.16**	10,060,000	$	0.16

The following table summarizes stock options outstanding and exercisable under the plan at December 31, 2018.

	Options outstanding			**Options exercisable**	
Exercise price ($)	Number outstanding at period end	Weighted average remaining contractual life	Weighted average exercise price	Number exercisable at period end	Weighted average exercise price
$0.16	12,800,000	2.58	$0.16	12,800,000	$0.16

The potential diluted number of common shares outstanding is as follows:

	September 30, 2018
Common shares	149,600,768
Options	12,800,000
Total common shares (diluted)	162,400,768

Liquidity and capital resources

As at December 30, 2018, the Corporation had $76,766 (December 31, 2017 - $221,461) in cash. The Corporation was unable to pay debenture interest of $157,500 as described in *Debenture,* was unable to pay convertible note payable interest of $6,575 as described in *Convertible note payable* and has a working capital deficiency of $5,641,812 (December 31, 2017 - $4,323,318). In recognition of these conditions, the Corporation negotiated in the second quarter of 2018, a credit facility not exceeding $1,500,000 which is further described below in *Convertible Note Payable*, has taken steps to reduce operational costs and will seek the continued support of the debenture holder. In addition, an additional credit facility was negotiated in 2019 for $2 million is further detailed in the section, "*Subsequent events"*. These undertakings, while significant, may not be sufficient in and of themselves to enable the Corporation to fund all aspects of future operations, and accordingly, management will need to pursue other financing alternatives to fund the Corporation so that it may continue as a going concern. The necessary financing may require the issuance of equity and/or debt instruments. There is no assurance that such initiatives may be successful.

The Corporation expects to generate sufficient funds from future operations in order to adequately fund general operations with savings from a cost reduction program and with the credit facilities now finalized but may require additional funds in order to meet the expenditures further described below under *Material Contracts, Commitments and Contingencies.*

The pace of future capital investment and the related financial liabilities incurred from the capital investment program will be dependent upon the Corporation's capacity to secure additional equity/debt financing on favorable terms. The Corporation had no defaults or breaches on any of its financial liabilities other than the payment of debenture interest as previously discussed.

Material Contracts, Commitments and Contingencies

Office lease

The Corporation has an office lease that requires monthly payments of $8,288 and expired March 29, 2019. The lease has been extended to July 31, 2019 at a cost of $8,000 per month.

During the year ended December 31, 2018, the Corporation expensed $82,843 relating to operating leases (2017 - $110,807).

Drilling commitments

The Corporation has an extension, subject to regulatory approval, to drill one well on its existing leases by November 30, 2019 at a cost of approximately $650,000.

Under the Development Agreement discussed below, the Corporation is required to spud five (5) test wells and complete, cap, plug or abandon the drilled wells. If the wells are not drilled by the expiry date, the lease shall then terminate with respect to all spacing units within the Leased Lands. The expiry dates are as follows:

- On or before September 30, 2019, one well must be spud
- Between March 31, 2019 and March 30, 2020, an additional two (2) wells must be spud
- Between March 31, 2020 and March 30,2021, an additional two (2) wells must be spud

The Corporation may be required to secure debt and/or equity financing in order to meet their future capital commitment otherwise the petroleum and natural gas leases may not be renewed.

Decommissioning obligations

Pursuant to the Inactive Well Compliance Program ("IWC Program"), the Alberta Energy Regulator (the "AER") identified 13 wells in which the Corporation has a working interest that required some form of surface and/or downhole reclamation work. The AER requested the work be completed by March 31, 2019. Due to unusually inclement weather in the Cold Lake area this winter, there remains 6 of the 13 wells that require reclamation work under the IWC Program. The Corporation is currently awaiting the end of Spring breakup to recommence the work which it expects to complete in July 2019. While the Corporation has not technically complied with its notification requirements under the IWC Program, the AER has not issued any final notices or enforcement action pertaining to its obligations under the IWC Program nor indicated any such notice or action is forthcoming. The Corporation's estimates the reclamation work will cost a total of $90,000 and that amount has been included in the current portion of decommissioning liabilities on the Consolidated Statement of Financial Position at December 31, 2018.

Litigation

During the year ended December 31, 2014, Macquarie Capital Markets Canada Ltd. filed a Statement of Defense and Counterclaim against the Corporation in response to a Statement of Claim filed by the Corporation against Macquarie in the Court of Queen's Bench of Alberta on July 7, 2014. The Corporation has not recorded a contingent liability associated with the Counterclaim as the Corporation is of the opinion the Counterclaim is without merit. The Corporation is continuing with its lawsuit against Macquarie and its defense of the Counterclaim.

Development Agreement

On May 9, 2018, the Corporation entered into a development agreement (the "Agreement") for $250,000 with Bigstone Oil & Gas Ltd., the wholly-owned energy company of the Bigstone Cree Nation. The Agreement provides for the development of an initial 3,040 acres of oil and gas rights from surface to the base of the Mannville in the Wabasca area of north-central Alberta under lease to Bigstone Oil & Gas Ltd. (the "Lease"). The Lease provides for an Alberta Provincial Crown equivalent royalty with a minimum rate of 10%. Under the terms of the Agreement, PetroFrontier, as operator, has the right to earn a 90% before payout working interest and 50% after payout working interest in five earning wells to be drilled by March 31, 2021 and a 50% working interest in the balance of the Lease.

Financial Instruments and Other Instruments

The Corporation's financial instruments consist of cash, trade and other receivables, trade and other payables, convertible note payable and the debenture. It is management's opinion that the Corporation is not exposed to significant interest, currency or credit risks arising from these financial instruments and that the fair value of these financial instruments approximates their carrying values, as applicable.

Credit risk

Credit risk is primarily related to the Company's trade receivables from petroleum and natural gas marketers and the risk of financial loss if a marketer fails to meet its contractual obligation. The Company's policy to mitigate credit risk associated with these receivables is to establish marketing relationships with large, credit worthy purchasers. The Company has not experienced any collection issues with its petroleum and natural gas marketers. As at December 31, 2018, the Corporation's trade accounts receivables were minimal. No default on outstanding receivables is anticipated and, as such, no provision for doubtful accounts has been recorded.

Interest rate risk

At December 31, 2018 and 2017, the Corporation had no outstanding floating interest rate debt and is not exposed to interest rate risk at this time.

Liquidity risk

Liquidity risk relates to the risk the Corporation will encounter difficulty in meeting obligations associated with financial liabilities. The current fixed financial liabilities on its statement of financial position are limited to accounts payable and accrued liabilities. The Corporation anticipates it will continue to have adequate liquidity to fund its existing current financial liabilities and ongoing operating and general administrative expenses through future operations with the closing of the new credit facility (see *"Convertible note payable"*) and with the continued support of the debenture holder. The pace of future capital investment and the related financial liabilities incurred from the capital investment program will be dependent upon the Corporation's capacity to access additional capital on favorable terms. The Corporation expects to substantially satisfy obligations under current trade and other payables over the next year as described previously in the section, *"Liquidity and capital resources"*.

Summary of Quarterly Results (unaudited)

Fiscal Quarter Ended - $	**December 31, 2018**	**September 30, 2018**	**June 30, 2018**	**March 31, 2017**
Revenue	275,430	1,070,613	1,283,113	928,568
Net loss	976,151	577,907	112,328	623,822
Net loss per share	0.01	0.00	0.00	0.01

Fiscal Quarter Ended - $	**December 31, 2017**	**September 30, 2017**	**June 30, 2017**	**March 31, 2016**
Revenue	1,125,571	1,537,431	1,351,015	1,354,047
Net (income) loss	658,691	258,649	428,766	415,400
Net (income) loss per share	0.00	0.00	0.00	0.01

The loss in the third quarter of 2017 is lower than the other 2017 quarterly losses as production was higher in the third quarter resulting in increased revenues to cover fixed costs.

Related parties

The Corporation is related to Kasten as a director of the Corporation is also an officer of Kasten. Pursuant to the Agreement of Purchase & Sale regarding the Kasten assets, Kasten agreed to act as a bare trustee which primarily included receiving the monthly cash receipts from petroleum and natural gas sales and forwarding the monies to the Corporation.

Other related party transactions are as follows:

- The $3,000,000 debenture issued to Kasten as part of the 2016 purchase consideration remains outstanding.
- Interest expense for the year ended December 31, 2018 related to Kasten debenture (note 6) of $90,000 (2017 - $107,243) was recorded in the Statement of Loss and Comprehensive Loss. At December 31, 2018, $157,500 (December 31, 2017 - $67,500) remains unpaid and is included in trade and other payables.
- The convertible note payable of $500,000 is owing to a company controlled by a director. Interest expense for the year ended December 31, 2018 of $23,342 and a $10,000 structuring fee was paid and recorded in the Statement of Loss and Comprehensive Loss. At December 31, 2018, interest payable of $6,575 is included in trade and other payables.
- During 2018, the Corporation acquired $2,205 (2017 - $567,962) of drilling inventory at fair value from a supplier in which a director holds an interest. At December 31, 2018, $128,696 (December 31, 2017 - $294,265) is included in trade and other payables.

Subsequent event

2019 Credit facility

On April 23, 2019, the Corporation signed a Term Sheet with a corporation controlled by a director which will provide for a credit facility not exceeding $2,000,000. The advances under the credit facility will bear interest at 8% per annum payable monthly, are secured by a General Security Agreement with a minimum advance being at least $200,000.

The lender will have the option to convert the advances under the credit facility into common shares of the Corporation. The conversion price of the common shares of the Corporation shall be (i) the closing price of the shares of the Corporation on the TSXV on the day of acceptance for the first year of the term of the loan and (ii) $0.10 for the second year of the term of the loan.

The finalization of this credit facility agreement is subject to due diligence and regulatory approval. This credit facility is for a term of two years will mature on April 23, 2021.

Off Balance Sheet Arrangements

The Corporation had no guarantees or off-balance sheet arrangements except for certain lease agreements that were entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases on the balance sheet as at December 31, 2018. The total future obligation from these operating leases is described above in the section "Material Contracts, Commitments and Contingencies".

Accounting Standards Adopted in the First Quarter of 2018

IFRS 9 – Financial Instruments

Effective January 1, 2018, the Corporation adopted *IFRS 9 – Financial Instruments* (“IFRS 9”) which supersedes *IAS 39 – Financial instruments: recognition and measurement (“IAS 39”).* The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: amortized cost and fair value. Under IFRS 9, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity’ own credit risk is recoded through other comprehensive income (loss) rather than net income (loss). The new standard also introduces a credit loss model for evaluating impairment of financial assets. There is no significant effect on the carrying value of other financial instruments under IFRS 9 related to this new requirement.

Under IFRS 9, financial assets are classified and measured based on the business model in which they are held and the characteristics of their contractual cash flows. IFRS 9 contains three primary measurement categories for financial assets: measured at amortized cost, fair value through other comprehensive income (‘FVTOCI”) and fair value through profit and loss (“FVTPL”). The IFRS 9 accounting model for financial liabilities is broadly the same as that in IAS 39 meaning that most financial liabilities will continue to be measured at amortized cost.

IFRS 9 replaces the “incurred loss” model in IAS 39 with a forward-looking “expected credit loss” (“ECL”) model for determining impairment or recognition of credit losses on financial assets measured at amortized cost (“AC”) or at FVTOCI. There is no impact to the Corporation as credit losses have been non-existent as the customers have had strong credit.

Below is a summary indicating the classification and measurement bases of the Corporation’s financial instruments as at January 1, 2018, as a result of adopting IFRS 9 along with a comparison to IAS 39.

Financial Instrument	**IAS 39**		**IFRS 9**	
Asset	Classification	Measurement	Classification	Measurement
Cash	Amortized cost	Amortized cost	Amortized cost	Amortized cost
Trade and other receivables	Loans and receivables	Amortized cost	Amortized cost	Amortized cost
Deposits	Loans and receivables	Amortized cost	Amortized cost	Amortized cost
Liabilities				
Trade and other payables	Other financial liabilities	Amortized cost	Amortized cost	Amortized cost
Debentures < 1 year	Other financial liabilities	Amortized cost	Amortized cost	Amortized cost

IFRS 15 – Revenue from Contracts with Customers

This standard provides a single model that applies to contracts with customers as well as two revenue recognition approaches: at a point in time or over time. The model features a contract-based, five-step analysis of transactions to determine whether, when and the amount of revenue is recognized. The new standard applies to contracts with customers. The new revenue standard permits a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. The Corporation adopted the modified retrospective method.

The Corporation reviewed its revenue streams and major contracts with customers under IFRS 15 and determined there were not material changes to net loss or timing of petroleum revenue recognized. The Corporation had adopted the modified retrospective basis.

Under IFRS 15, revenue from the sale of commodities is calculated by reference to consideration specified in contracts with customers and recognized when control of the product is transferred to the buyer. The nature of each its performance obligations, including roles of their parties and partners, are evaluated to determine if the Company acts as a principal and therefore revenues on a gross basis or as an agent and therefore recognizes revenue on a net basis. The Corporation would act as a principal when it controls the product delivered before the control passes to the customer.

Revenue from the sale of crude oil is recognized based on the consideration specified in contracts with customers. The Corporation recognizes revenue when control of the product transfers to the buyer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or battery.

When allocating the transaction price realized in contracts with multiple performance obligations, the Corporation is required to make estimates of the prices at which the product would sell separately to customers. The corporation does not currently have ant contracts with multiple performance obligations.

Accounting Standard Issued but Not Yet Applied

In January 2016, the IASB issued IFRS 16, *"Leases"* ("IFRS 16") to replace IAS 17, *"Leases"*. Under IFRS 16, a single recognition and measurement model will apply for lessees, which will require recognition of assets and liabilities for most leases. IFRS 16 is effective for years beginning on or after January 1, 2019 with earlier adoption permitted. The adoption of IFRS 16 on the Corporation's consolidated financial statements will have minimal impact.

Business Risks and Uncertainties

The Corporation's business is subject to risks inherent in oil and natural gas exploration and development operations. In addition, there are risks associated with the Corporation's current and future operations in the jurisdictions in which it operates. The Corporation has identified certain risks pertinent to its business including: exploration and reserve risks, drilling and operating risks, changes to regulatory requirements, costs and availability of materials and services, capital markets and the requirement for additional capital, loss of or changes to joint venture or related agreements, economic and sovereign risks, reliance on joint venture partners, market risk, volatility of future oil and natural gas prices and foreign currency risk. Management seeks to reduce such risks by employing professionals and utilizing consultants and contractors to conduct the business of the Corporation in strict compliance with corporate governance, operating, safety, health and environmental requirements and best practices.

Further, in this regard, management also places great emphasis on fostering and maintaining a strong working relationship with its partners, CLFN and its wholly-owned energy company, with respect to the on-going development of CLFN lands.

Limited Operating and Earnings History

The Corporation has no earnings history. The Corporation's future business plans may require significant expenditure, particularly capital expenditure, in the establishment of Canadian oil and gas operations. Any future profitability from the Corporation's business will be dependent upon the successful acquisition of new lands, and there can be no assurance that the Corporation will achieve profitability in the future.

Investment Risks

The timing and extent of revenues is variable and uncertain and accordingly the Corporation is unable to predict when, if at all, profitability will be achieved. An investment in the Common Shares is highly speculative and should only be made by persons who can afford a significant or total loss of their investment.

History of Losses

The Corporation has historically incurred losses from operations. As at December 31, 2018, the Corporation had a cumulative deficit of $126,874,527. There can be no assurance that the Corporation will achieve profitability in the future. In addition, should the Corporation be unable to continue as a going concern, realization of assets and settlement of liabilities other than in the normal course of business may be at amounts significantly different from those in the financial statements.

Cash Flow Used in Operations

The Corporation's cash used in excess of the cash generated from operations in 2018 was $437,570. The Corporation has a history of negative cash flow from operations and the inability of the Corporation to generate positive operating cash inflow in the future could have a material adverse impact on its business, operations and prospects.

Competition

Oil and gas exploration is intensely competitive in all phases and involves a high degree of risk. The Corporation competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to add reserves in the future will depend not only on its ability to explore and develop properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Competition may also be presented by alternate fuel sources.

Operational Dependence

In the future, the Corporation may enter into operations in which it is not the operator or which may be dependent or effected by the activities or conduct of third parties. As such, the Corporation may have limited ability to exercise influence or control over the operation of such assets or their associated costs, which could adversely affect the Corporation's financial performance. Therefore, the Corporation's return on such operations will depend upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, an operator's or other third party's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Reliance on Key Personnel

The Corporation's success will depend in large measure on the performance of the Board and other key personnel. The loss of services of such individuals could have a material adverse effect on the Corporation. The Corporation does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Corporation are likely to be of central importance. In addition, there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Assessments of Value of Acquisitions

Acquisitions of oil and natural gas issuers and oil and natural gas assets are typically based on engineering and economic assessments made by independent engineers and the Corporation's own assessments. These assessments will include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the Corporation's control. In particular, the prices of, and markets for, oil and natural gas products may change from those anticipated at the time of making such assessment. In addition, all such assessments involve a measure of geological and engineering uncertainty which could result in lower than anticipated production and reserves. Initial assessments of acquisitions may be based on reports by a firm of independent engineers that are not the same as the firm that the Corporation may use for its year-end reserve evaluations. Because each of these firms may have different evaluation methods and approaches, these initial assessments may differ significantly from the assessments of the firm used by the Corporation. Any such instance may offset the return on and value of the Common Shares.

Estimate of Fair Market Value

There are numerous uncertainties inherent in an estimate of fair market value including many factors beyond the Corporation's control. The valuations herein represent estimates only. In general, estimates are based upon a number of variable factors and assumptions, such as engineering and geophysical information pertaining to hydrocarbon potential, current material contracts of the Corporation, production history of competitors on similar land positions, access to lands, availability, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies, and future operating costs, all of which may vary from actual results. All such estimates are to some degree speculative and are only attempts to define the degree of speculation involved.

Insurance

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. However, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not be insurable in all circumstances or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any such uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Corporation's financial position, results of operations or prospects. The Corporation believes it is adequately insured for normal risks.

Corporate Matters

The Corporation does not anticipate the payment of any dividends on the Common Shares for the foreseeable future. Certain directors and officers of the Corporation are also directors and officers of other oil and natural gas companies involved in natural resource exploration and development, and conflicts of interest may arise between their duties as directors and officers of the Corporation and as directors and officers of such other companies. Such conflicts must be disclosed in accordance with and are subject to such other procedures and remedies as applicable under, the Alberta Business Corporations Act.

Title to Properties

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of the Corporation. To the extent title defects do exist, it is possible the Corporation may lose all or a portion of its right, title, estate and interest in and to the properties to which the title relates.

Additional Funding Requirements

The Corporation will require additional financing from time to time in order to carry out oil and natural gas exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to have limited ability to expend the capital necessary to undertake or complete future exploration programs, forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Moreover, future activities may require the Corporation to alter its capitalization significantly.

Dilution

The Corporation may make future acquisitions or enter into financing or other transactions involving the issuance of securities of the Corporation, which may be dilutive to existing shareholders.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations.
Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and the potential for increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge.

Statutory provisions require petroleum tenement lands to be protected and rehabilitated to ensure that environmental damage is avoidable or minimal where authorized. These provisions may require approvals and consents to be obtained before certain lands may be accessed and explored. In addition, each state and territory government may impose a wide range of obligations on tenement holders to ensure that petroleum operations comply with various environmental standards and requirements.

No assurance can be given that environmental laws will not result in a curtailment of future production (if any) or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects.

Changes in Legislation

Legislation and regulations continue to be introduced by government and government agencies concerning the security of industrial facilities, including oil and natural gas facilities. The Corporation's operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs the Corporation could incur to comply with any such laws or regulations, but such expenditures could be substantial.

Income Taxes

The Corporation will file all required income tax returns and believes that it will be in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable tax legislation. However, such returns are subject to reassessment by applicable taxation authorities. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Integrity of Disclosure

The Corporation's management maintains appropriate information systems, procedures and controls to ensure that information used internally and disclosed externally is complete and reliable.

The Board is responsible for ensuring that management fulfills its responsibilities. The Audit Committee fulfills its role of ensuring the integrity of the reported information through its review of the audited consolidated financial statements. The Board approves the annual audited consolidated financial statements and MD&A on the recommendation of the Audit Committee.

The Corporation has approved a series of policy papers that include Code of Business Conduct and Ethics, Whistle Blower Policy and Procedures, Insider Trading and Reporting Guidelines, Disclosure Policy and Board Control System. Terms of References define Audit Committee and Compensation and Governance Committees. The Corporation has a defined Board Mandate.

Additional Information

Additional information on the Corporation can be accessed at www.sedar.com or from the Corporation’s website at www.petrofrontier.com or by contacting the Corporation at PetroFrontier Corp., Suite 900, 903 - 8th Avenue S.W. Calgary, Alberta, Canada T2P 0P7.

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Businessman
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Michael Hibberd
Businessman
Calgary, Alberta

Paul Cheung
Businessman
Calgary, Alberta

Kelly Kimbley
President
Calgary, Alberta

Officers

Kelly Kimbley
CEO and
President

Robert L. Gillies
Vice-President Finance,
Secretary and
Chief Financial Officer

Ulrich Wirth
Vice-President Exploration

Omar El-Hajjar
Vice-President Operations

David Orr
Vice-President Business Development

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Auditors

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