Petrus Resources

MANAGEMENT'S DISCUSSION & ANALYSIS

September 30, 2019

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The following is Management's Discussion and Analysis ("MD&A") of the financial and operating results of Petrus Resources Ltd. ("Petrus" or the "Company") as at and for the three and nine months ended September 30, 2019. This MD&A is dated November 12, 2019 and should be read in conjunction with the Company's September 30, 2019 interim consolidated financial statements and the December 31, 2018 audited consolidated financial statements. The Company's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). Readers are directed to the "Advisories" section at the end of this MD&A regarding forward-looking statements and boe presentation and to the section "Non-GAAP Financial Measures" herein.

The principal undertaking of Petrus is the investment in energy assets. The operations of the Company consist of the acquisition, development, exploration and exploitation of these assets. The Company's head office is located at 2400, 240 - 4th Avenue SW, Calgary, Alberta, Canada. Additional information on Petrus, including the most recently filed Annual Information Form ("AIF"), are available under the Company's profile on SEDAR (the System for Electronic Document Analysis and Retrieval) at www.sedar.com.

SELECTED FINANCIAL INFORMATION

OPERATIONS	Three months ended Sept. 30, 2019	Three months ended Sept. 30, 2018	Three months ended Jun. 30, 2019	Three months ended Mar. 31, 2019	Three months ended Dec. 31, 2018
Average Production					
Natural gas (mcf/d)	30,998	33,461	32,350	32,145	30,480
Oil (bbl/d)	1,247	1,243	1,679	1,704	1,358
NGLs (bbl/d)	1,372	1,519	1,576	1,444	1,496
Total (boe/d)	**7,785**	**8,338**	**8,647**	**8,505**	**7,934**
Total (boe)	**716,220**	**767,095**	**786,819**	**765,488**	**730,819**
Light oil weighting	16%	15%	19%	20%	17%
Realized Prices					
Natural gas ($/mcf)	1.12	1.50	1.30	2.44	1.95
Oil ($/bbl)	65.64	77.24	70.96	55.10	52.26
NGLs ($/bbl)	11.49	45.27	19.91	36.02	29.01
Total realized price ($/boe)	**16.99**	**25.79**	**22.29**	**26.36**	**21.91**
Royalty income	0.48	0.32	0.15	0.06	0.10
Royalty expense	(1.65)	(3.12)	(1.72)	(3.08)	(3.34)
Net oil and natural gas revenue ($/boe)	**15.82**	**22.99**	**20.72**	**23.34**	**18.67**
Operating expense	(4.44)	(4.95)	(4.33)	(3.76)	(5.28)
Transportation expense	(1.25)	(0.98)	(1.22)	(1.27)	(1.17)
Operating netback[1] ($/boe)	**10.13**	**17.06**	**15.17**	**18.31**	**12.22**
Realized gain (loss) on derivatives ($/boe)	0.50	(2.69)	(1.02)	0.67	(0.79)
Other income	0.03	0.08	0.10	—	0.37
General & administrative expense	(1.08)	(1.72)	(0.67)	(1.15)	(1.46)
Cash finance expense	(3.11)	(2.53)	(2.70)	(2.54)	(3.25)
Decommissioning expenditures	(0.29)	(0.20)	(0.24)	(0.18)	(0.21)
Funds flow & corporate netback[1][2] ($/boe)	**6.18**	**10.00**	**10.64**	**15.11**	**6.88**

FINANCIAL (000s except $ per share)	Three months ended Sept. 30, 2019	Three months ended Sept. 30, 2018	Three months ended Jun. 30, 2019	Three months ended Mar. 31, 2019	Three months ended Dec. 31, 2018
Oil and natural gas revenue	12,517	20,030	17,652	20,231	16,064
Net income (loss)	(29,569)	(8,048)	2,863	(12,138)	21,063
Net income (loss) per share					
Basic	(0.60)	(0.16)	0.06	(0.25)	0.43
Fully diluted	(0.60)	(0.16)	0.06	(0.25)	0.43
Funds flow	4,427	7,685	8,366	11,573	5,030
Funds flow per share					
Basic	0.09	0.16	0.17	0.23	0.10
Fully diluted	0.09	0.16	0.17	0.23	0.10
Capital expenditures	2,734	3,637	2,505	8,483	12,660
Net dispositions	651	50	—	—	6
Weighted average shares outstanding					
Basic	49,469	49,492	49,469	49,483	49,492
Fully diluted	49,469	49,492	49,469	49,483	49,492
As at period end					
Common shares outstanding					
Basic	49,469	49,492	49,469	49,469	49,492
Fully diluted	49,469	49,492	49,469	49,469	49,492
Total assets	296,367	322,335	328,912	336,974	341,820
Non-current liabilities	82,650	170,908	81,249	176,093	171,646
Net debt[1]	128,553	131,603	130,619	136,382	139,214

[1] *Refer to "Non-GAAP Financial Measures" in the Management's Discussion & Analysis attached hereto.*
[2] *Corporate netback is equal to funds flow which is a comparable additional GAAP measure. Petrus analyzes these measures on an absolute value and per unit basis.*

CREDIT FACILITY UPDATE

Subsequent to September 30, 2019 Petrus completed its semi-annual credit facility review where the $100 million facility was reconfirmed. Lender consent is still required for borrowings above $95 million.

The Company's revolving credit facility's ("RCF") maturity date is May 31, 2020 which was set prior to the Company's term loan maturity of October 8, 2020 ("Term Loan"), due to the inter-creditor relationship between the RCF and the Term Loan. The Company requires an extension or refinancing of its Term Loan before the syndicate of lenders will contemplate an extension to the RCF. The borrowings under the RCF are classified as a current liability in the September 30, 2019 interim consolidated financial statements which has no impact on the debt covenants and the Company remains, and expects to continue to be, in compliance with each of its covenants. Management is actively engaged with the RCF syndicate of lenders and the Term Loan lender and we believe that the RCF and Term Loan will each be extended prior to May 31, 2020. The Company continues its efforts to divest certain non-core assets to improve its balance sheet.

During the third quarter the Company determined there were indicators of impairment of its non-core assets through information obtained through the divestiture process to date. Petrus recognized an impairment loss of $24.7 million for the three and nine months ended September 30, 2019.

OPERATIONS UPDATE

Production

Third quarter average production by area was as follows:

For the three months ended September 30, 2019	Ferrier	Foothills	Central Alberta	Total
Natural gas (mcf/d)	23,488	1,513	5,997	30,998
Oil (bbl/d)	729	133	385	1,247
NGLs (bbl/d)	1,200	6	166	1,372
Total (boe/d)	**5,844**	**391**	**1,550**	**7,785**

Third quarter average production was 7,785 boe/d in 2019 compared to 8,647 boe/d in the second quarter of 2019. Third quarter development activity was postponed to prioritize debt repayment and the Company has not brought on new production since the first quarter of 2019. The Company's drilling activity resumed late in the third quarter of 2019 with 4 gross (1.6 net) Cardium light oil wells drilled. The completion, tie-in and production attributed to these wells commenced early in the fourth quarter. Estimated production from the first 3 (1.2 net) wells over the first few weeks, net to Petrus, was approximately 800 bbl/d of light oil and approximately 1,000 mcf/d of natural gas. The Company's development plan is strategically balanced between increasing its Cardium light oil weighting in the Ferrier area and continuing to improve its balance sheet. To date in 2019, Petrus drilled 7 gross (3.1 net) Cardium light oil wells, increased its light oil weighting 23% from the beginning of 2018 and reduced net debt $10.7 million or 8% since December 31, 2018.

The average benchmark natural gas price in Canada (AECO 5A monthly index) was $0.91/mcf in the third quarter of 2019. This was the lowest quarterly average benchmark natural gas price since the Company's inception in 2011. In late September, TC Energy announced implementation of a revised operating protocol for balancing the NGTL pipeline during periods of planned system maintenance. This Temporary Service Protocol ("TSP") came into effect September 30, 2019 and applies to April to October maintenance periods. Following the announcement, AECO prices increased to average over $2.60/mcf for the second half of October, with the average monthly price settling at $2.21/mcf. Forward AECO strip pricing for calendar 2020 has been improving and is currently approximately $2.00/mcf. Petrus anticipates the impacts of the TSP, continued expansion of the NGTL system in 2020 and 2021 and low Alberta natural gas storage levels will all aid in reducing price volatility and improving support for Canadian natural gas.

Natural gas liquids ("NGLs") have also been subject to pricing pressure in 2019. Spot market pricing for propane and butane was approximately 35% lower than the prior year for the first nine months of 2019. Petrus' ownership and control of critical processing facilities enables the Company to respond and continually optimize its production revenue streams. To improve operating netback, during the third quarter, Petrus ceased sending certain natural gas for additional third party deep-cut processing to extract additional NGLs. This resulted in lower NGL production volume, however the heating value of natural gas sales increased and processing fees decreased. Petrus continues to monitor NGL market pricing and is able to modify its operations accordingly.

Petrus' Board of Directors has approved a fourth quarter 2019 capital budget of $5.5 million, based on a current forecast for commodity futures pricing, anticipated service costs and current activity levels. The fourth quarter budget is expected to include the drilling and completion activities for 3 gross (0.1 net) Cardium light oil wells as well as the completion and tie-in activities for the 1.6 net wells drilled in the third quarter. Excess cash flow of $2 to $3 million will be directed toward debt repayment.

Petrus estimates the 2019 capital plan will maintain production year over year, increase its light oil and liquids weighting, and reduce debt. Approximately 90% of the capital plan will be directed to development of Cardium light oil wells in the Ferrier area of Alberta, which we estimate will have payouts of less than one year and achieve the objective of increasing the Company's light oil weighting and funds flow.

Petrus believes that it is unique in the junior E&P company space, as few gas-weighted companies are able to repay debt and grow production and cash flow all within cash from operations. Over the past four years, Petrus has dramatically improved its business in order to increase its sustainability as well as mitigate commodity price risk. Operating costs have been reduced by 50% since 2015 and Petrus' total cash costs of $9.85/boe are consistently one of the lowest amongst its peers. The Company intends to continue its disciplined focus on balance sheet improvement and capital deployment in 2020. The capital plan targets modest cash flow and production growth while directing in excess of $10 million toward debt reduction in 2020.

(1)Refer to "Non-GAAP Financial Measures."
(2)Refer to "Advisories - Forward-Looking Statements."

RESULTS OF OPERATIONS

FINANCIAL AND OPERATIONAL RESULTS OF OIL AND NATURAL GAS ACTIVITIES

	Three months ended Sept. 30, 2019	Three months ended Sept. 30, 2018	Three months ended Jun. 30, 2019	Three months ended Mar. 31, 2019	Three months ended Dec. 31, 2018
Average production					
Natural gas (mcf/d)	30,998	33,461	32,350	32,145	30,480
Oil (bbl/d)	1,247	1,243	1,679	1,704	1,358
NGLs (bbl/d)	1,372	1,519	1,576	1,444	1,496
Total (boe/d)	**7,785**	**8,338**	**8,647**	**8,505**	**7,934**
Total (boe)	**716,220**	**767,095**	**786,819**	**765,488**	**730,819**
Revenue ($000s)					
Natural Gas	3,192	4,630	3,839	7,051	5,473
Oil	7,529	8,828	10,841	8,450	6,522
NGLs	1,450	6,326	2,855	4,681	3,993
Royalty revenue	346	246	117	49	76
Oil and natural gas revenue	**12,517**	**20,030**	**17,652**	**20,231**	**16,064**
Average realized prices					
Natural gas ($/mcf)	1.12	1.50	1.30	2.44	1.95
Oil ($/bbl)	65.64	77.24	70.96	55.10	52.26
NGLs ($/bbl)	11.49	45.27	19.91	36.02	29.01
Total realized price ($/boe)	16.99	25.79	22.29	26.36	21.91
Hedging gain (loss) ($/boe)	0.50	(2.69)	(1.02)	0.67	(0.79)
Total price including hedging ($/boe)	**17.49**	**23.10**	**21.27**	**27.03**	**21.12**

Average benchmark prices	Three months ended Sept. 30, 2019	Three months ended Sept. 30, 2018	Three months ended Jun. 30, 2019	Three months ended Mar. 31, 2019	Three months ended Dec. 31, 2018
Natural gas					
AECO 5A (C$/GJ)	0.87	1.13	0.98	2.48	1.47
AECO 7A (C$/GJ)	0.99	1.28	1.11	1.84	1.80
Crude Oil					
Mixed Sweet Blend Edm (C$/bbl)	69.21	79.65	72.66	67.46	48.12
Natural Gas Liquids					
Propane Conway (US$/bbl)	15.56	31.97	20.60	24.40	29.11
Butane Edmonton (C$/bbl)	24.78	31.52	24.43	5.91	13.52
Foreign Exchange					
US$/C$	0.76	0.77	0.75	0.75	0.76

FUNDS FLOW AND NET LOSS

Petrus generated funds flow of $4.4 million in the third quarter of 2019 compared to $7.7 million in the third quarter of 2018. The 42% decrease is due in part to the 7% decrease in production from the prior year as development activity was postponed to prioritize debt repayment and the Company has not brought on new production since the first quarter of 2019. In addition, commodity prices were significantly lower in the third quarter of 2019 compared to the prior year. The AECO 5A monthly index was 24% lower, Canadian light oil mixed sweet blend was 13% lower and NGL market prices were approximately 30% (depending on the product) lower than the prior year.

For the nine months ended September 30, 2019, Petrus generated funds flow of $24.4 million compared to $28.2 million in the prior period. The 13% decrease is primarily due to lower production as the Company has prioritized debt repayment through 2019. Offsetting an 11% decrease in production during the period, the Company's total liquids production weighting increased 20% from the prior year as a result of the Company's shift in focus to light oil development. Changes in commodity prices were less significant between 2019 and 2018 on a nine month basis. The AECO 5A monthly index was 3% higher, Canadian light oil mixed sweet blend was 8% lower and NGL market prices were 30% to 40% (depending on the product) lower than the prior year.

Petrus reported a net loss of $29.6 million and $38.8 million in the three and nine months ended September 30, 2019, respectively, compared to a net loss of $8.0 million and $24.3 million for the prior year comparative periods. The net loss during the three and nine months ended September 30, 2019 is primarily due to the $24.7 million impairment expense recorded during the third quarter on the Company's non-core Foothills and Central Alberta assets. three and nine months ended September 30, 2018

($000s except per share)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Funds flow	**4,427**	**7,685**	**24,365**	**28,154**
Funds flow per share - basic	0.09	0.16	0.49	0.57
Funds flow per share - fully diluted	0.09	0.16	0.49	0.57
Net loss	**(29,569)**	**(8,048)**	**(38,844)**	**(24,347)**
Net loss per share - basic	(0.60)	(0.16)	(0.79)	(0.49)
Net loss per share - fully diluted	(0.60)	(0.16)	(0.79)	(0.49)
Common shares outstanding (000s)				
Basic	49,469	49,492	49,469	49,492
Fully diluted	49,469	49,492	49,469	49,492
Weighted average shares outstanding (000s)				
Basic	49,469	49,492	49,472	49,492
Fully diluted	49,469	49,492	49,472	49,492

OIL AND NATURAL GAS REVENUE

Average production for the third quarter of 2019 was 7,785 boe/d (16% light oil), 7% lower than the 8,338 boe/d (15% light oil) average production for the third quarter of the prior year as the Company did not drill additional wells or bring on new production in the second or third quarter as development activity was postponed to prioritize debt repayment. In addition, the Company continues to shift its focus to increasing its light oil weighting through development of its Cardium light oil inventory which results in higher value production, but lower total production on a per boe basis. Total oil and natural gas revenue for the third quarter of 2019 was $12.5 million compared to $20.0 million in the third quarter of 2018. The 38% decrease is due to significantly lower commodity prices in addition to the 7% decrease in production. The AECO 5A monthly index was 23% lower, Canadian light oil mixed sweet blend was 13% lower and NGL market prices were 20% to 50% (depending on the product) lower than the prior year.

Average production for the nine months ended September 30, 2019 was 8,310 boe/d (19% light oil), compared to 9,384 boe/d (15% light oil) for the prior year. Total oil and natural gas revenue decreased from $64.7 million in the first nine months of 2018 to $50.4 million in the nine months ended September 30, 2019 due to 11% lower production and lower commodity pricing. Canadian light oil mixed sweet blend was 8% lower and NGL market prices were 30% to 40% (depending on the product) lower than the prior year.

Natural gas

The average benchmark natural gas price in Canada (AECO 5A monthly index) was 24% lower and 3% higher than the prior year for the three and nine months ended September 30, 2019, respectively (average price of $0.91/mcf in the third quarter of 2019 compared to $1.19/mcf in the third quarter of the prior year, and $1.52/mcf for the first nine months of 2019, compared to $1.48/mcf for the prior year comparative period).

The Company's average realized natural gas price during the third quarter of 2019 was $1.12/mcf, compared to $1.50/mcf in the third quarter of 2018, which represents a 25% decrease. Natural gas revenue for the third quarter of 2019 was $3.2 million and production of 2,851,788 mcf, which accounted for approximately 66% of third quarter production volume and 26% of oil and natural gas revenue, compared to revenue of $4.6 million and production of 3,078,426 mcf accounting for approximately 15% of third quarter production volume and 32% of oil and natural gas revenue in the prior year. Natural gas revenue for the third quarter decreased from the prior year due to 7% lower natural gas production and 24% lower natural gas pricing.

Natural gas revenue for the nine months ended September 30, 2019 was $14.1 million and production was 8,688,660 mcf, which accounted for approximately 64% of production volume and 28% of oil and natural gas revenue, compared to revenue of $18.0 million and production of 10,737,795 mcf for 70% of production volume and 28% of oil and natural gas revenue in the prior year. The decrease is due to 11% lower natural gas production offset by 3% higher natural gas pricing.

Crude oil and condensate

The Canadian mixed sweet blend oil price was 13% and 9% lower than the prior year for the three and nine months ended September 30, 2019, respectively (average price of $69.21/bbl for the third quarter of 2019 compared to $79.65/bbl for the prior year and $69.78/bbl in the nine months ended September 30, 2019 compared to $76.95/bbl in the prior year).

The average realized price of Petrus' light oil and condensate was $65.64/bbl for the third quarter of 2019 compared to $77.24/bbl for the prior year. The decrease of 15% is attributable to the 13% decrease in the market price of Canadian light sweet mixed blend. In addition, the Company's focus on Cardium light oil development has resulted in its light oil density increasing relative to the condensate stream previously produced through its Cardium liquids rich natural gas development.

Oil and condensate revenue for the third quarter of 2019 was $7.5 million and production of 114,698 bbl accounted for approximately 16% of total production volume and 60% of oil and natural gas revenue, compared to revenue of $8.8 million and production of 114,291 bbl accounting for approximately 15% of total production volume and 44% of oil and natural gas revenue in the prior year.

Oil and condensate revenue for the nine months ended September 30, 2019 was $26.8 million and production of 421,070 bbl, which accounted for approximately 19% of total production volume and 54% of oil and natural gas revenue, compared to revenue of $29.2 million and production of 386,889 bbl, which accounted for approximately 15% of total production volume and 45% of oil and natural gas revenue in the prior year.

Natural gas liquids (NGLs)

The Company's NGL production mix consists of ethane, propane, butane and pentane. The pricing received for NGL production is based on annual contracts effective the first of April each year. The contract prices are based on the product mix, the fractionation process required and the demand for fractionation facilities. In the third quarter of 2019, the Company's realized NGL price averaged $11.49/bbl, compared to $45.27/bbl in the prior year. The decrease is attributed to lower contract prices for the NGL byproducts. Third quarter market pricing for propane at Conway decreased 51% from the prior year and similarly, butane at Edmonton decreased 21% over the same period.

Petrus' ownership and control of critical processing facilities enables the Company to respond and continually optimize its production revenue streams. To improve operating netback, during the third quarter, Petrus ceased sending certain natural gas for additional third party deepcut processing to extract additional NGLs. This resulted in lower NGL production volume, however, the heating value of natural gas sales increased and processing fees decreased. Petrus continues to monitor NGL market pricing and is able to modify its operations accordingly.

NGL revenue for the third quarter of 2019 was $1.5 million, and production of 126,224 bbl accounted for approximately 18% of production volume and 12% of oil and natural gas revenue, compared to revenue of $6.3 million and production of 139,733 bbl accounting for approximately 18% of production volume and 45% of oil and natural gas revenue for the prior year.

NGL revenue for the nine months ended September 30, 2019 was $9.0 million and production of 399,605 bbl, which accounted for approximately 17% of production volume and 18% of oil and natural gas revenue, compared to revenue of $17.2 million and production of 385,487 bbl accounting for approximately 15% of production volume and 27% of oil and natural gas revenue in the prior year.

ROYALTY EXPENSE

Royalties are paid to the Government of Alberta and to gross overriding royalty owners. The following table shows the Company's royalty expense for the periods shown:

Royalty Expense ($000s)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Crown	**599**	684	**2,066**	3,193
Percent of production revenue	**5%**	3%	**4%**	5%
Gross overriding	**583**	1,707	**2,830**	6,009
Total	**1,182**	**2,391**	**4,896**	**9,202**

Total royalty expense (net of royalty allowances and incentives) decreased from $2.4 million in the third quarter of 2018 to $1.2 million in the third quarter of 2019 primarily due to 7% lower production and lower commodity prices. On a nine month basis, total royalty expense (net of royalty allowances and incentives) decreased from $9.2 million in 2018 to $4.9 million in 2019. The decrease is due to lower commodity prices and production.

Gross overriding royalties decreased from $1.7 million in the third quarter of 2018 to $0.6 million in the third quarter of 2019, due to 7% lower production and lower light oil and NGL prices. Gross overriding royalties decreased from $6.0 million for the nine months ended September 30, 2018 to $2.8 million for the nine months ended September 30, 2019, due to the decrease in production and commodity prices.

RISK MANAGEMENT

The Company utilizes financial derivative contracts to mitigate commodity price risk and provide stability and sustainability to the Company's economic returns, funds flow and capital development plan. Petrus' risk management program is governed by guidelines approved by its Board of Directors.

The impact of the contracts that were outstanding during the reporting periods are actual cash settlements and are recorded as realized hedging gains (losses). The unrealized gain (loss) is recorded to demonstrate the change in fair value of the outstanding contracts during the financial reporting period for financial statement purposes. Petrus does not follow hedge accounting for any of its risk management contracts in place. Petrus considers all of its risk management contracts to be effective economic hedges of its underlying business transactions.

The table below shows the realized and unrealized gain or loss on risk management contracts for the periods shown:

Net Gain (Loss) on Financial Derivatives ($000s)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Realized hedging gain (loss)	**360**	(2,061)	**73**	(2,388)
Unrealized hedging gain (loss)	**1,368**	(3,997)	**(7,605)**	(17,860)
Net gain (loss) on derivatives	**1,728**	**(6,058)**	**(7,532)**	**(20,248)**

The Company recognized a realized hedging gain of $0.4 million during the third quarter of 2019, compared to a $2.1 million loss realized in the prior year. The realized gain in the current period is due to lower gas prices (relative to the respective contracts outstanding). The realized gain in the third quarter of 2019 increased the Company's total realized price by $0.50/boe, compared to the realized loss in the third quarter of the prior year, which decreased the Company's total realized price by $2.69/boe.

The Company recognized a realized hedging gain of $0.1 million during the nine months ended September 30, 2019, compared to the $2.4 million loss realized in the prior year. The realized gain is due to lower gas prices (relative to the respective contracts outstanding).

The unrealized hedging gain of $1.4 million for the three months ended September 30, 2019 represents the change in the unrealized net risk management position during the quarter. The unrealized hedging loss of $7.6 million for the nine months ended September 30, 2019 represents the change in the unrealized risk management net asset position during the first nine months of 2019. This change is a result of both the realization of hedging gains in the period, changes related to contracts entered into during the period as well as changes to commodity prices.

The change in the Company's net risk management position between the second and third quarter of 2019 was a result of the difference in quarter ending oil prices, which is used to calculate the risk management asset or liability mark-to-market value. The WTI price decreased by 7%, from $58.20/bbl (USD) as at June 30, 2019 to $54.09/bbl (USD) as at September 30, 2019. At June 30, 2019, the unrealized risk management net mark-to-market value was a $0.5 million asset compared to September 30, 2019 when the unrealized risk management net mark-to-market value was a $1.9 million asset, which resulted in the $1.4 million unrealized hedging gain recorded in the third quarter of 2019.

The Company's risk management contracts provide protection from significant changes in crude oil and natural gas commodity prices for 2019, 2020 and 2021. The Company endeavors to hedge approximately half of its forecast production for the following year, and at least 30% of its forecast production for the subsequent year. The Company's hedging strategy is intended to provide stability and sustainability to the Company's economic returns, funds flow and capital development plan. A summary of Petrus' risk management contracts is included in note 9 of the Company's interim consolidated financial statements as at and for the period ended September 30, 2019. The table below summarizes Petrus' average crude oil and natural gas hedged volumes. The average volume of oil hedged for the remainder of 2019 (1,650 bbl/d) represents 63% of third quarter 2019 average liquids (oil and NGL) production. The 16,500 GJ/day average natural gas hedged for the remainder of 2019 represents 50% of third quarter 2019 average natural gas production.

The following table summarizes the average and minimum and maximum cap and floor prices for the 2019 to 2021 oil and natural gas contracts outstanding as at the date of this MD&A:

	2019					2020					2021				
	Q1	Q2	Q3	Q4	Avg.[1]	Q1	Q2	Q3	Q4	Avg.[1]	Q1	Q2	Q3	Q4	Avg.[1]
Oil hedged (bbl/d)	1,650	1,400	1,400	1,650	**1,525**	1,450	1,150	950	750	**1,075**	500	300	300	300	**350**
Avg. WTI cap price ($C/bbl)	68.46	67.13	69.26	70.45	**68.88**	73.23	76.33	76.71	75.12	**75.16**	72.83	74.02	72.80	72.80	**73.07**
Avg. WTI floor price ($C/bbl)	68.17	67.13	69.26	70.45	**68.80**	73.23	76.33	76.71	75.12	**75.16**	72.83	74.02	72.80	72.80	**73.07**
Natural gas hedged (GJ/d)	21,000	16,000	16,000	16,500	**17,375**	15,500	11,500	11,500	8,500	**11,750**	7,000	4,000	4,000	1,333	**4,083**
Avg. AECO 7A cap price ($C/GJ)	2.47	1.70	1.70	1.75	**1.94**	1.76	1.51	1.51	1.59	**1.61**	1.63	1.60	1.60	1.60	**1.61**
Avg. AECO 7A floor price ($C/GJ)	2.47	1.70	1.70	1.75	**1.94**	1.76	1.51	1.51	1.59	**1.61**	1.63	1.60	1.60	1.60	**1.61**

[1]The volumes and prices reported are the weighted average volumes and prices for the period.

OPERATING EXPENSE

The following table shows the Company's operating expense for the reporting periods shown:

Operating Expense ($000s)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Fixed and variable operating expense	**2,456**	3,594	**7,860**	10,123
Processing, gathering and compression charges	**980**	464	**2,340**	2,478
Total gross operating expense	**3,436**	**4,058**	**10,200**	**12,601**
Processing income recoveries	**(255)**	(258)	**(734)**	(800)
Total net operating expense	**3,181**	**3,800**	**9,466**	**11,801**
Operating expense, net ($/boe)	**4.44**	**4.95**	**4.17**	**4.61**

Operating expense (net of processing income and overhead recoveries) totaled $3.2 million for the third quarter of 2019, a 16% decrease from the $3.8 million recorded in the prior year. On a per boe basis, operating expense for the third quarter was 10% lower at $4.44/boe in 2019 compared to $4.95/boe in 2018. The decreases are attributable to improved operating efficiencies (on a total and per boe basis) as well as a 7% decrease in production.

For the nine months ended September 30, 2019, operating expense (presented net of processing income and overhead recoveries) totaled $9.5 million, a 20% decrease from the $11.8 million in the prior year. The decrease is attributable to Petrus' improved operating cost structure and decreased activity related to well workover projects. On a per boe basis, operating expense for the nine months ended September 30, 2019 was $4.17/boe, 10% lower than the $4.61/boe in the prior year. The decrease is attributed to less workover activity, offset by an 11% decrease in production.

TRANSPORTATION EXPENSE

The following table shows transportation expense paid in the reporting periods:

Transportation Expense ($000s)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Transportation expense	**893**	749	**2,823**	2,934
Transportation expense ($/boe)	**1.25**	0.98	**1.24**	1.15

Petrus pays commodity and demand charges for transporting its gas on pipeline systems. The Company also incurs trucking costs on the portion of its oil and natural gas liquids production that is not pipeline connected. Transportation expense totaled $0.9 million or $1.25/boe in the third quarter of 2019 ($0.7 million or $0.98/boe in the prior year). The increase in transportation expense is attributed to increased tolls on midstream pipelines, increased NGL volume transported via truck and offset by 7% lower production. On a nine month basis, transportation expense totaled $2.8 million, or $1.24/boe, compared to $2.9 million or $1.15/boe in the prior year. The increase in transportation expense per boe is attributed to increased trucking costs.

GENERAL AND ADMINISTRATIVE EXPENSE

The following table illustrates the Company's general and administrative ("G&A") expense which is shown net of capitalized costs directly related to exploration and development activities:

General and Administrative Expense ($000s)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Personnel, consultants and directors	**706**	903	**2,643**	3,362
Administrative expenses	**268**	792	**933**	1,935
Regulatory and professional expenses	**264**	128	**671**	684
Gross general and administrative expense	**1,238**	**1,823**	**4,247**	**5,981**
Capitalized general and administrative expense	**(336)**	(345)	**(1,067)**	(1,231)
Overhead recoveries	**(126)**	(161)	**(995)**	(631)
General and administrative expense	**776**	**1,317**	**2,185**	**4,119**
General and administrative expense ($/boe)	**1.08**	**1.72**	**0.96**	**1.61**

G&A expense (net of capitalized G&A expense and overhead recoveries) for the third quarter of 2019 totaled $0.8 million or $1.08/boe, compared to $1.3 million or $1.72/boe in the third quarter of 2018. Gross G&A expense (before capitalized G&A expense and overhead recoveries) was 32% lower than the prior year ($1.2 million in the third quarter of 2019 compared to $1.4 million in the third quarter of 2018).

For the nine months ended September 30, 2019, G&A expense totaled $2.2 million or $0.96/boe compared to $4.1 million or $1.61/boe for the prior year.

The decreases in G&A, for the three and nine month periods, are due to lower office rent which is now accounted for as finance and depreciation expense under IFRS 16 (refer to note 7 in the Company's September 30, 2019 interim consolidated financial statements) as well as lower office expenses and staffing costs due to fewer personnel.

SHARE-BASED COMPENSATION EXPENSE

The following table illustrates the Company's share-based compensation expense which is shown net of capitalized costs directly related to exploration and development activities:

Share-Based Compensation Expense ($000s)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Gross share-based compensation expense	**113**	174	**404**	529
Capitalized share-based compensation expense	**(45)**	(70)	**(162)**	(212)
Share-based compensation expense	**68**	**104**	**242**	**317**

Share-based compensation expense (net of capitalized portion) was $0.1 million for the third quarter of 2019, which is consistent with the $0.1 million recognized in the third quarter of the prior year.

For the nine months ended September 30, 2019, share-based compensation expense (net of capitalized portion) was $0.2 million, which is consistent with the prior year.

FINANCE EXPENSE

The following table illustrates the Company's finance expense which includes cash and non-cash expenses:

Finance Expense ($000s)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Interest expense	**2,230**	1,941	**6,302**	5,903
Deferred financing costs	**117**	196	**374**	463
Accretion on decommissioning obligations	**189**	217	**601**	663
Total finance expense	**2,536**	**2,354**	**7,277**	**7,029**

The Company incurred total finance expense of $2.5 million in the third quarter of 2019, comprised of $0.2 million of non-cash accretion of its decommissioning obligations, $2.2 million of cash interest expense and $0.1 million of deferred financing fee amortization, both of which are related to the RCF and Term Loan. In the third quarter of 2018, the Company incurred total finance expense of $2.4 million, comprised of $0.2 million in non-cash accretion of its decommissioning obligation, $6.3 million cash interest expense and $0.2 million of deferred financing fee amortization. The increase in total finance expense from the prior year is due to higher interest costs paid.

The Company incurred total finance expense of $7.3 million for the nine months ended September 30, 2019, which is consistent with the $7.0 million for the prior year. The increase is due to higher interest costs paid.

The Company's decommissioning obligations at September 30, 2019 were $46.6 million, which increased $6.4 million from $40.2 million at December 31, 2018. The primary reason for the increase in the discounted obligation from December 31, 2018 is the decrease in the risk free rate. Refer to note 8 of the Company's interim consolidated financial statements as at and for the period ended September 30, 2019 for further information.

DEPLETION AND DEPRECIATION

The following table compares depletion and depreciation expense recorded in the reporting periods shown:

Depletion and Depreciation Expense ($000s)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Depletion and depreciation expense	**8,895**	9,631	**27,829**	31,744
Depletion and depreciation expense ($/boe)	**12.42**	12.56	**12.27**	12.39

Depletion and depreciation expense is calculated on a unit-of-production (boe) basis. This fluctuates period to period primarily as a result of changes in the underlying proved plus probable reserve base and in the amount of costs subject to depletion and depreciation, including future development cost. Such costs are segregated and depleted on an area by area basis relative to the respective underlying proved plus probable reserve base.

Petrus recorded depletion and depreciation expense in the third quarter of 2019 of $8.9 million or $12.42/boe, compared to the third quarter of 2018, when $9.6 million or $12.56/boe was recorded. For the nine months ended September 30, 2019, the Company recorded $27.8 million or $12.27/boe, compared to $31.7 million or $12.39/boe for the prior year. The decreases are due to lower production volume.

IMPAIRMENT

The following table illustrates impairment losses recorded in the reporting periods:

Impairment ($000s)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Impairment	**24,655**	—	**24,655**	—
Total	**24,655**	—	**24,655**	—

Petrus has certain CGUs that are not core to the Company. As such, a process has been in place to potentially divest of the Company's Foothills and Central Alberta CGUs. Based on interest expressed in the Foothills and Central Alberta assets, and information obtained through the divestiture process to date, the Company determined there were indicators of impairment. Petrus recognized an impairment loss of $24.7 million for the three and nine months ended September 30, 2019, compared to the prior year comparative periods where no impairment loss was recorded.

SHARE CAPITAL

The Company's authorized share capital consists of an unlimited number of common shares ("Common Shares") and an unlimited number of preferred shares ("Preferred Shares"). The Company has not issued any Preferred Shares. The following table details the number of issued and outstanding securities for the periods shown:

Share Capital (000s)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Weighted average Common Shares outstanding				
Basic	**49,469**	49,492	**49,472**	49,492
Fully diluted	**49,469**	49,492	**49,472**	49,492
Common Shares outstanding				
Basic	**49,469**	49,492	**49,469**	49,492
Fully diluted	**49,469**	49,492	**49,469**	49,492
Stock options outstanding	**2,343**	3,071	**2,343**	3,071

At September 30, 2019, the Company had 49,469,358 Common Shares and 2,343,085 stock options outstanding.

The Company issued 690,000 stock options during the nine months ended September 30, 2019:

(a) 390,000 stock options were issued on March 22, 2019 at an exercise price of $0.45.
(b) 300,000 stock options were issued on June 10, 2019 at an exercise price of $0.32.

The Company has a deferred share unit plan in place whereby it may issue deferred share units to directors of the Company. At September 30, 2019, 739,046 (December 31, 2018 – 382,796) deferred share units ("DSUs") were issued and outstanding. Each DSU entitles the participants to receive, at the Company's discretion, either shares of the Company or cash equivalent to the number of DSUs multiplied by the current trading price of the equivalent number of Common Shares of the Company. All DSUs vest and become payable upon retirement of the director.

LIQUIDITY AND CAPITAL RESOURCES

Petrus has two debt instruments outstanding. The first is a reserve-based, senior secured revolving credit facility with a syndicate of lenders, which is the RCF. The second is the Term Loan.

(a) Revolving Credit Facility

At September 30, 2019, the RCF was comprised of a $20 million operating facility and an $80 million syndicated term-out facility. Lender consent is required for borrowings exceeding $95 million and the RCF is due on May 31, 2020. The Company has provided collateral by way of a debenture over all of the present and after acquired property of the Company. Subsequent to September 30, 2019 Petrus completed its semi-annual credit facility review where the $100 million facility was reconfirmed. Lender consent is still required for borrowings above $95 million. The RCF's maturity date is May 31, 2020 which was set prior to the Term Loan maturity of October 8, 2020 due to the inter-creditor relationship between the RCF and the Term Loan. The Company requires an extension or refinancing of its Term Loan before the syndicate of lenders will contemplate an extension to the RCF.

At September 30, 2019, the Company had a $0.7 million letter of credit outstanding against the RCF (December 31, 2018 – $0.7 million) and had drawn $89.9 million against the RCF (December 31, 2018 – $97.0 million).

The amount of the RCF is subject to a borrowing base review performed on a semi-annual basis by the lenders, based primarily on reserves and commodity prices estimated by the lenders as well as other factors. In addition, asset dispositions require unanimous lender consent. A decrease in the borrowing base could result in a reduction to the available credit under the RCF. The next scheduled borrowing base redetermination date for the RCF is on or before May 31, 2020. In the event that the lenders reduce the borrowing base below the amount drawn at the time of redetermination, the Company has 60 days to eliminate any shortfall by repaying amounts in excess of the new re-determined borrowing base.

(b) Term Loan

At September 30, 2019, the Company had a $35 million (December 31, 2018 – $35 million) Term Loan outstanding (excluding $0.4 million of deferred finance fees), which is due October 8, 2020. The Term Loan bears interest which is due and payable monthly and accrues at a per annum rate of the (three-month) Canadian Dealer Offered Rate plus 700 basis points. The Company has provided collateral by way of a debenture over all of the present and after acquired property of the Company.

Financial Covenants

The RCF and the Term Loan carry financial covenants that are described in note 8 of the Company's December 31, 2018 audited annual consolidated financial statements. The Company was in compliance with all financial covenants at September 30, 2019.

Liquidity Risk
Liquidity risk relates to the risk the Company will encounter difficulty in meeting obligations associated with its financial liabilities that are settled by cash as they become due. The Company's approach to managing liquidity risk is to ensure, as much as possible, that it will have sufficient liquidity to meet its short-term and long-term financial obligations when due, under both normal and unusual conditions without incurring unacceptable losses or risking harm to the Company's reputation. The financial liabilities on its balance sheet consist of bank indebtedness, accounts payable, long term debt (including current portion thereof) and risk management liabilities.

At September 30, 2019, the Company had a working capital deficiency (excluding non-cash risk management assets and liabilities) of $94.0 million which has increased by $86.2 million from $7.8 million on December 31, 2018 primarily due to the reclassification of the Company's borrowings under its RCF. The RCF's maturity date is May 31, 2020 due to the inter-creditor relationship between the RCF and the Company's Term Loan which is due October 8, 2020. The Company requires an extension or refinancing of its Term Loan before the syndicate of lenders will contemplate an extension. The borrowings under the RCF are classified as a current liability in the September 30, 2019 interim consolidated financial statements which has no impact on the debt covenants and we remain in compliance with each of our covenants. Management is actively engaged with the RCF syndicate of lenders and the Term Loan lender and we believe that the RCF and Term Loan will each be extended prior to May 31, 2020. The Company continues its efforts to divest certain non-core assets to improve the balance sheet.

The currently challenged economic environment could result in adverse changes in cash flows, net debt balances, reduction in the borrowing base of the Company's credit facility or breach of the financial covenants noted within its credit agreements. However, the Company remains in compliance with all financial covenants pertaining to its debt, and based on current available information relating to future production volumes, forward commodity pricing, future costs including capital, operating and general and administrative, forward exchange rates, interest rates and taxes, all of which are subject to measurement uncertainty, management expects to comply with all financial covenants during the subsequent 12 month period.

The following are the contractual maturities of financial liabilities as at September 30, 2019:

$000s	**Total**	**< 1 year**	**1-5 years**
Accounts payable and accrued liabilities	13,792	13,792	—
Risk management liability	338	204	134
Bank indebtedness and long term debt[1]	124,850	89,850	35,000
Total	**138,980**	**103,846**	**35,134**

[1]*Excludes deferred finance fees.*

The commitments for which the Company is responsible are as follows:

$000s	**Total**	**< 1 year**	**1-5 years**	**> 5 years**
Firm service transportation	**18,147**	**1,740**	**12,011**	**4,396**

Risk Management
Petrus is engaged in the acquisition, development, exploration and exploitation of oil and natural gas in western Canada. The Company is exposed to a number of risks, both financial and operational, through the pursuit of its strategic objectives. Actively managing these risks improves the ability to effectively execute Petrus' business strategy. Financial risks associated with the oil and natural gas industry include fluctuations in commodity prices, interest rates, currency exchange rates and the cost of goods and services. Financial risks also include third party credit risk and liquidity risk. Operational risks include reservoir performance uncertainties, competition, regulatory, environment and safety concerns.

For a more in-depth discussion of risk management, see notes 9 and 14 of the Company's September 30, 2019 interim consolidated financial statements.

CAPITAL EXPENDITURES

Capital expenditures (excluding acquisitions and dispositions) totaled $2.7 million in the third quarter of 2019, compared to $3.6 million in the prior year. The Company participated in the drilling activities for 4 (1.2 net) Cardium light oil wells in Ferrier during the third quarter however the completion and tie-in activities will not be recorded until the fourth quarter. In the prior year the Company drilled and completed a total of 2 (1.0 net) wells and those wells were finished and brought on production during the quarter.

Capital expenditures (excluding acquisitions and dispositions) totaled $13.8 million in the nine months ended September 30, 2019, compared to $11.5 million in the prior year. The Company did not bring on new production in the second or third quarter as development activity was postponed to prioritize debt repayment. The decrease from the prior year is attributed to 7 (3.1 net) wells drilled in the nine months ended September 30, 2019, compared to 4 (1.6 net) wells in the prior year.

The following table shows capital expenditures for the reporting periods indicated. All capital is presented before decommissioning obligations.

Capital Expenditures ($000s)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Drill and complete	**2,305**	2,741	**9,736**	6,082
Oil and gas equipment	**40**	368	**2,855**	2,550
Land and lease	**—**	106	**19**	1,612
Capitalized general and administrative expense	**389**	422	**1,146**	1,252
Total capital expenditures	**2,734**	**3,637**	**13,756**	**11,496**
Gross (net) wells spud	**4 (1.2)**	**2 (1.0)**	**7 (3.1)**	**4 (1.6)**

During the three and nine months ended September 30, 2019, Petrus divested of non-core assets for approximately $0.7 million. Petrus divested non-core assets for approximately $0.4 million during the nine months ended September 30, 2018.

The following table summarizes the dispositions for the reporting periods indicated:

Dispositions ($000s)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Dispositions	**651**	50	**651**	448
Total dispositions	**651**	**50**	**651**	**448**

SUMMARY OF QUARTERLY RESULTS

($000s unless otherwise noted)	Sept. 30, 2019	Jun. 30, 2019	Mar. 31, 2019	Dec. 31, 2018	Sept. 30, 2018	Jun. 30, 2018	Mar. 31, 2018	Dec. 31, 2017
Average Production								
Natural gas (mcf/d)	30,998	32,350	32,145	30,480	33,461	39,126	45,543	46,625
Oil (bbl/d)	1,247	1,679	1,704	1,358	1,243	1,484	1,530	1,854
NGLs (bbl/d)	1,372	1,576	1,444	1,496	1,519	1,241	1,475	1,086
Total (boe/d)	**7,785**	**8,647**	**8,505**	**7,934**	**8,338**	**9,246**	**10,596**	**10,711**
Total (boe)	**716,220**	**786,819**	**765,488**	**730,819**	**767,095**	**841,316**	**953,598**	**985,388**
Financial Results								
Oil and natural gas revenue	12,517	17,652	20,231	16,064	20,030	19,321	25,301	23,243
Royalty expense	(1,182)	(1,355)	(2,359)	(2,436)	(2,391)	(2,137)	(4,674)	(3,000)
Net oil and natural gas revenue	**11,335**	**16,297**	**17,872**	**13,628**	**17,639**	**17,184**	**20,627**	**20,243**
Transportation expense	(893)	(959)	(971)	(855)	(749)	(988)	(1,197)	(1,233)
Operating expense	(3,181)	(3,405)	(2,880)	(3,851)	(3,800)	(3,841)	(4,160)	(4,744)
Operating netback	**7,261**	**11,933**	**14,021**	**8,922**	**13,090**	**12,355**	**15,270**	**14,266**
Realized gain (loss) on derivatives	360	(800)	513	(573)	(2,061)	(625)	298	1,210
Other income	21	78	—	268	69	103	—	—
General and administrative expense	(776)	(530)	(879)	(1,065)	(1,317)	(1,372)	(1,430)	(266)
Cash finance expense	(2,230)	(2,126)	(1,945)	(2,370)	(1,941)	(2,097)	(1,865)	(1,515)
Decommissioning expenditures	(209)	(189)	(137)	(152)	(155)	—	(168)	(611)
Corporate netback and funds flow	**4,427**	**8,366**	**11,573**	**5,030**	**7,685**	**8,364**	**12,105**	**13,084**
Oil and natural gas revenue	**12,517**	**17,652**	**20,231**	**16,064**	**20,030**	**19,321**	**25,301**	**23,243**
Per share - basic	0.25	0.36	0.41	0.32	0.40	0.39	0.51	0.47
Per share - fully diluted	0.25	0.36	0.41	0.32	0.40	0.39	0.51	0.47
Net income (loss)	**(29,569)**	**2,863**	**(12,138)**	**21,063**	**(8,048)**	**(10,615)**	**(5,684)**	**(67,095)**
Per share - basic	(0.60)	0.06	(0.25)	0.43	(0.16)	(0.21)	(0.11)	(1.36)
Per share - fully diluted	(0.60)	0.06	(0.25)	0.43	(0.16)	(0.21)	(0.11)	(1.36)
Common shares outstanding (000s)								
Basic	49,469	49,469	49,469	49,492	49,492	49,492	49,492	49,492
Fully diluted	49,469	49,469	49,469	49,492	49,492	49,492	49,492	49,492
Weighted average shares outstanding (000s)								
Basic	49,469	49,469	49,483	49,492	49,492	49,492	49,492	49,456
Fully diluted	49,469	49,469	49,483	49,492	49,492	49,492	49,492	49,456
Total assets	296,367	328,912	336,974	341,820	322,335	330,359	343,161	353,445
Net debt	(128,553)	(130,619)	(136,382)	(139,214)	(131,603)	(135,111)	(142,238)	(148,066)

The oil and natural gas exploration and production industry is cyclical in nature. Petrus' financial position, results of operations and corporate netback are affected by commodity prices, exchange rates, Canadian price differentials and production levels. Petrus’ average quarterly production decreased from 10,711 boe/d in the fourth quarter of 2017 to 7,785 boe/d in the third quarter of 2019. The 38% production decrease is attributable to Petrus' shift in focus to liquids production growth in order to maximize value in light of the current natural gas commodity price environment as well as certain development activity postponed to prioritize debt repayment. In addition the decrease is due to certain production volume in the Foothills area being shut-in due to uneconomic natural gas pricing.

Commodity price improvements enable higher reinvestment in exploration, development and acquisition activities as they increase the cash flows from operating activities. Commodity price reductions reduce revenues received and can challenge the economics of the Company's development program as the quantity of reserves may not be economically recoverable. Petrus' investment in its assets, and its ability to replace and grow reserve volumes, will be dependent on its ability to obtain debt and equity financing as well as the funds it receives from operations.

CRITICAL ACCOUNTING ESTIMATES

The timely preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of the financial statements are outlined below. The Company’s critical accounting estimates can be read in note 2 to the Company’s consolidated financial statements as at and for the year ended December 31, 2018.

OTHER FINANCIAL INFORMATION

Significant accounting policies

The Company’s significant accounting policies can be read in note 3 of the Company’s audited consolidated financial statements as at and for the year ended December 31, 2018.

New standards and interpretations

The Company's discussion on new standards and interpretations can be read in note 2 of the Company’s interim financial statements as at and for the period ended September 30, 2019.

Internal Control over Financial Reporting

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on July 1, 2019 and ending on September 30, 2019 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

NON-GAAP FINANCIAL MEASURES

This MD&A makes reference to the terms "operating netback", "corporate netback" and "net debt". These indicators are not recognized measures under GAAP (IFRS) and do not have a standardized meaning prescribed by GAAP (IFRS). Accordingly, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. Management uses these terms for the reasons set forth below.

Operating Netback

Operating netback is a common non-GAAP financial measure used in the oil and natural gas industry which is a useful supplemental measure to evaluate the specific operating performance by product at the oil and natural gas lease level. The most directly comparable GAAP measure to operating netback is funds flow. Operating netback is calculated as oil and natural gas revenue less royalties, operating and transportation expenses. It is presented on an absolute value and per unit basis.

Funds Flow and Corporate Netback

Corporate netback is a common non-GAAP financial measure used in the oil and natural gas industry which evaluates the Company’s profitability at the corporate level. Corporate netback is equal to funds flow which is a directly comparable GAAP measure. Petrus analyzes these measures on an absolute value and per unit basis. Management believes that funds flow and corporate netback provide information to assist a reader in understanding the Company's profitability relative to current commodity prices. It is calculated, in the following table, as the operating netback less general and administrative expense, finance expense, decommissioning expenditures, plus other income and the net realized gain (loss) on financial derivatives.

	Three months ended Sept. 30, 2019		Three months ended Sept. 30, 2018		Nine months ended Sept. 30, 2019		Nine months ended Sept. 30, 2018	
	$000s	$/boe	$000s	$/boe	$000s	$/boe	$000s	$/boe
Oil and natural gas revenue	12,517	17.47	20,030	26.11	50,400	22.22	64,652	25.23
Royalty expense	(1,182)	(1.65)	(2,391)	(3.12)	(4,896)	(2.16)	(9,202)	(3.59)
Net oil and natural gas revenue	**11,335**	**15.82**	**17,639**	**22.99**	**45,504**	**20.06**	**55,450**	**21.64**
Transportation expense	(893)	(1.25)	(749)	(0.98)	(2,823)	(1.24)	(2,934)	(1.15)
Operating expense	(3,181)	(4.44)	(3,800)	(4.95)	(9,466)	(4.17)	(11,801)	(4.61)
Operating netback	**7,261**	**10.13**	**13,090**	**17.06**	**33,215**	**14.65**	**40,715**	**15.88**
Realized gain (loss) on financial derivatives	360	0.50	(2,061)	(2.69)	73	0.03	(2,388)	(0.93)
Other income	21	0.03	69	0.08	99	0.04	172	0.10
General & administrative expense	(776)	(1.08)	(1,317)	(1.72)	(2,185)	(0.96)	(4,119)	(1.61)
Interest expense	(2,230)	(3.11)	(1,941)	(2.53)	(6,302)	(2.78)	(5,903)	(2.30)
Decommissioning expenditures	(209)	(0.29)	(155)	(0.20)	(535)	(0.24)	(323)	(0.13)
Funds flow and corporate netback	**4,427**	**6.18**	**7,685**	**10.00**	**24,365**	**10.74**	**28,154**	**11.01**

Net Debt

Net debt is a non-GAAP financial measure and is calculated as current assets (excluding unrealized financial derivative assets) less current liabilities (excluding unrealized financial derivative liabilities, right-of-use lease obligations, and deferred share unit liabilities) and long term debt. Petrus uses net debt as a key indicator of its leverage and strength of its balance sheet. There is no GAAP measure that is reasonably comparable to net debt.

($000s)	**As at September 30, 2019**	**As at December 31, 2018**
Adjusted current assets[(1)]	**9,759**	14,035
Less: adjusted current liabilities[(1)]	**(103,642)**	(21,827)
Less: long term debt	**(34,670)**	(131,422)
Net debt	**(128,553)**	**(139,214)**

[(1)] *Adjusted for unrealized risk management assets, liabilities, right-of-use lease obligations, and unrealized deferred share units liability.*

OIL AND GAS DISCLOSURES

Our oil and gas reserves statement for the year ended December 31, 2018, which includes disclosure of our oil and natural gas reserves and other oil and natural gas information in accordance with NI 51-101, is contained in the AIF. The recovery and reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered.

Management uses oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Petrus' operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this MD&A, should not be relied upon for investment.

ADVISORIES

Basis of Presentation

Financial data presented above has largely been derived from the Company's financial statements, prepared in accordance with GAAP which require publicly accountable enterprises to prepare their financial statements using IFRS. Accounting policies adopted by the Company are set out in the notes to the audited financial statements as at and for the twelve months ended December 31, 2018. The reporting and the measurement currency is the Canadian dollar. All financial information is expressed in Canadian dollars, unless otherwise stated.

Forward-Looking Statements

Certain information regarding Petrus set forth in this MD&A contains forward-looking statements within the meaning of applicable securities law, that involve substantial known and unknown risks and uncertainties. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. Such statements represent Petrus' internal projections, estimates or beliefs concerning, among other things, an outlook on the estimated amounts and timing of capital investment, anticipated future debt, production, revenues or other expectations, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. These statements are only predictions and actual events or results may differ materially. Although Petrus believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, competitive, political and social uncertainties and contingencies. Many factors could cause Petrus' actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Petrus.

In particular, forward-looking statements included in this MD&A include, but are not limited to, statements with respect to: the anticipated impacts of TSP; continued expansion of the NGTL system and low Alberta natural gas storage levels; Petrus' ability to modify its operations; Petrus' business plan and expected debt repayment in the fourth quarter of 2019 and the anticipated results thereof; Petrus' expected drilling and operations activities in the fourth quarter of 2019; the results of Petrus' 2019 capital plan and the targets thereof; Petrus' 2020 capital plan and the expected results thereof; expectations regarding the adequacy of Petrus' liquidity and the funding of its financial liabilities; Petrus' ability to extend the RCF and Term Loan and the timing thereof; the impact of the current economic environment on Petrus; the performance characteristics of the Company's crude oil, NGL and natural gas properties; future prospects; the focus of and timing of capital expenditures; access to debt and equity markets; Petrus' future operating and financial results; capital investment programs; supply and demand for crude oil, NGL and natural gas; future royalty rates; drilling, development and completion plans and the results therefrom; and treatment under governmental regulatory regimes and tax laws. In addition, statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

These forward-looking statements are subject to numerous risks and uncertainties, most of which are beyond the Company's control, including the impact of general economic conditions; volatility in market prices for crude oil, NGL and natural gas; industry conditions; currency fluctuation; imprecision of reserve estimates; liabilities inherent in crude oil and natural gas operations; environmental risks; incorrect assessments of the value of acquisitions and exploration and development programs; competition; the lack of availability of qualified personnel or management; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; stock market volatility; ability to access sufficient capital from internal and external sources; completion of the financing on the timing planned and the receipt of applicable approvals; and the other risks. With respect to forward-looking statements contained in this MD&A, Petrus has made assumptions regarding: future commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment and services; effects of regulation by governmental agencies; and future operating costs. Management has included the above summary of assumptions and risks related to forward-looking information provided in this MD&A in order to provide shareholders with a more complete perspective on Petrus' future operations and such information may not be appropriate for other purposes. Petrus' actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that the Company will derive therefrom. Readers are cautioned that the foregoing lists of factors are not exhaustive.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Petrus' prospective results of operations including, without limitation, its ability to repay debt, which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth above. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on FOFI. Petrus' actual results, performance or achievement could differ materially from those expressed in, or implied by, these FOFI, or if any of them do so, what benefits Petrus will derive therefrom. Petrus has included the FOFI in order to provide readers with a more complete perspective on Petrus' future operations and such information may not be appropriate for other purposes.

These forward-looking statements and FOFI are made as of the date of this MD&A and the Company disclaims any intent or obligation to update any forward-looking statements and FOFI, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

BOE Presentation

The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent ("boe") basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved measurement of results and comparisons with other industry participants. Petrus uses the 6:1 boe measure which is the approximate energy equivalence of the two commodities at the burner tip. Boe's do not represent an economic value equivalence at the wellhead and therefore may be a misleading measure if used in isolation.

Abbreviations

$000's	*thousand dollars*
$/bbl	*dollars per barrel*
$/boe	*dollars per barrel of oil equivalent*
$/GJ	*dollars per gigajoule*
$/mcf	*dollars per thousand cubic feet*
bbl	*barrel*
bbl/d	*barrels per day*
boe	*barrel of oil equivalent*
mboe	*barrel of oil equivalent*
mmboe	*thousand barrel of oil equivalent*
boe/d	*million barrel of oil equivalent per day*
GJ	*gigajoule*
GJ/d	*gigajoules per day*
mcf	*thousand cubic feet*
mcf/d	*thousand cubic feet per day*
mmcf/d	*million cubic feet per day*
NGLs	*natural gas liquids*
WTI	*West Texas Intermediate*