SECOND QUARTER REPORT

For the three and six months ended June 30, 2018

Petrus Resources Ltd. ("Petrus" or the "Company") (TSX: PRQ) is pleased to report financial and operating results for the second quarter of 2018.

In response to the commodity price outlook for natural gas, the Company shifted its focus in the first half of 2018 to improving its financial position and directing excess funds flow towards debt repayment. During the first half of 2018, Petrus reduced its net debt by $13.0 million or 9%. The Company's focus for the second half of 2018 is to prioritize light oil drilling opportunities in its core area, Ferrier, Alberta. The Company's 2018 capital program is scheduled to recommence in August and Petrus expects to drill an additional 7 (3.7 net) Cardium light oil wells during the second half of 2018. The program is expected to be funded through funds flow and the Company is targeting to end 2018 at its current level of net debt.

HIGHLIGHTS

- Petrus generated funds flow of $8.4 million in the second quarter of 2018 which is 33% lower than the $12.5 million generated in the second quarter of 2017. The decrease is primarily due to the 63% reduction in natural gas pricing (AECO 7A monthly index) in the comparable period. The impact of the lower gas price was partially offset by the Company's active hedging program. The quarterly average light oil price (Edm CAD$) increased 31% from the prior year which further offset the impact of the reduced natural gas prices.

- The Company has strategically focused on debt repayment in 2018 and has reduced net debt(1) by $13.0 million or 9% since December 31, 2017. As a result of the current commodity price environment, Petrus intends to direct its 2018 capital budget towards Cardium light oil development in Ferrier. Capital investment is expected to recommence in August(2).

- Second quarter average production was 9,246 boe/d in 2018 compared to 10,240 boe/d for the same period in 2017. The 10% decrease is attributable to certain dry gas production in the Foothills area which was shut-in due to uneconomic gas prices.

- Total operating expenses for the second quarter were 17% lower at $4.57 per boe in 2018 compared to $5.53 per boe in 2017(3). The Company continues to focus on lowering its operating costs, particularly in the Ferrier area, through facility ownership and control.

- Petrus 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. The Company realized a net loss on financial derivatives in the second quarter of 2018 of $0.6 million ($0.74 per boe) which is made up of a $3.2 million realized gain related to natural gas, offset by a $3.8 million net loss related to light oil. The amounts are due to the significant decrease in the price of natural gas and significant increase in the price of light oil, respectively. The Company endeavors to hedge approximately 50 to 70% of its forecast production for the following year, and approximately 30 to 50% of its forecast production for the subsequent year. As a percentage of second quarter 2018 production, Petrus has derivative contracts in place for 63% and 74% of its natural gas and oil and natural gas liquids production, respectively, for the remainder of 2018.

- During the second quarter of 2018, Petrus participated in the drilling of one (0.2 net) Cardium light oil well in the Ferrier area. The completion activities for the well were deferred to July due to spring break-up. The well was brought on production early in the third quarter.

(1) Refer to "Non-GAAP Financial Measures" in the Management's Discussion & Analysis attached hereto.
(2) Refer to "Advisories - Forward-Looking Statements" in the Management's Discussion & Analysis attached hereto.
(3) Refer to "Advisories - BOE Presentation" in the Management's Discussion & Analysis attached hereto.

MANAGEMENT'S DISCUSSION & ANALYSIS

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 six months ended June 30, 2018. The MD&A is dated August 8, 2018 and should be read in conjunction with the Company's June 30, 2018 interim consolidated financial statements and the December 31, 2017 audited annual 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 at the end of this report 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 Jun. 30, 2018	Three months ended Jun. 30, 2017	Three months ended Mar. 31, 2018	Three months ended Dec. 31, 2017	Three months ended Sept. 30, 2017
Average Production					
Natural gas (mcf/d)	39,126	42,392	45,543	46,625	45,550
Oil (bbl/d)	1,484	2,015	1,530	1,854	1,877
NGLs (bbl/d)	1,241	1,160	1,475	1,086	1,098
Total (boe/d)	**9,246**	**10,240**	**10,596**	**10,711**	**10,567**
Total (boe)	**841,316**	**931,821**	**953,598**	**985,388**	**972,140**
Natural gas sales weighting	71%	69%	72%	73%	72%
Realized Prices					
Natural gas ($/mcf)	1.24	3.29	2.18	1.90	1.66
Oil ($/bbl)	75.29	59.02	73.91	66.10	51.23
NGLs ($/bbl)	41.53	30.32	46.50	38.00	24.79
Total realized price ($/boe)	**22.92**	**28.69**	**26.50**	**23.56**	**18.82**
Royalty income	0.05	0.03	0.03	0.03	0.01
Royalty expense	(2.54)	(4.62)	(4.90)	(3.04)	(2.73)
Net oil and natural gas revenue ($/boe)	**20.43**	**24.10**	**21.63**	**20.55**	**16.10**
Operating expense	(4.57)	(5.53)	(4.36)	(4.81)	(5.42)
Transportation expense	(1.17)	(1.32)	(1.26)	(1.25)	(1.29)
Operating netback [(1)] ($/boe)	**14.69**	**17.25**	**16.01**	**14.49**	**9.39**
Realized gain (loss) on derivatives	(0.74)	0.23	0.31	1.23	1.88
Other income	0.12	—	—	—	—
General & administrative expense	(1.63)	(1.12)	(1.50)	(0.27)	(1.09)
Cash finance expense	(2.49)	(1.94)	(1.96)	(1.54)	(1.99)
Decommissioning expenditures	—	(1.03)	(0.23)	(0.62)	(0.23)
Corporate netback [(1)] ($/boe)	**9.95**	**13.39**	**12.63**	**13.29**	**7.96**

FINANCIAL ($000s except per share)	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Three months ended Mar. 31, 2018	Three months ended Dec. 31, 2017	Three months ended Sept. 30, 2017
Oil and natural gas revenue	19,321	26,753	25,301	23,243	18,299
Net loss	(10,615)	(781)	(5,684)	(67,095)	(50,696)
Net loss per share					
Basic	(0.21)	(0.02)	(0.11)	(1.36)	(1.03)
Fully diluted	(0.21)	(0.02)	(0.11)	(1.36)	(1.03)
Funds flow	**8,364**	**12,458**	**12,105**	**13,084**	**7,727**
Funds flow per share					
Basic	0.17	0.25	0.24	0.26	0.16
Fully diluted	0.17	0.25	0.24	0.26	0.16
Capital expenditures	**1,745**	**18,903**	**6,056**	**21,885**	**13,055**
Net acquisitions (dispositions)	(269)	—	(123)	789	(4,866)
Weighted average shares outstanding					
Basic	49,492	49,428	49,492	49,456	49,428
Fully diluted	49,492	49,428	49,492	49,456	49,428
As at period end					
Common shares outstanding (000s)					
Basic	49,492	49,428	49,492	49,492	49,428
Fully diluted	49,492	49,428	49,492	49,492	49,428
Total assets	330,359	465,794	343,161	353,445	409,078
Non-current liabilities	172,757	170,580	174,634	173,272	191,145
Net debt [(1)]	**135,111**	**137,069**	**142,238**	**148,066**	**137,531**

[(1)] *Refer to "Non-GAAP Financial Measures" in the Management's Discussion & Analysis attached hereto.*

OPERATIONS UPDATE

Production

Average second quarter production by area was as follows:

For the three months ended June 30, 2018	Ferrier	Foothills	Central Alberta	Total
Natural gas (mcf/d)	28,734	3,225	7,167	39,126
Oil (bbl/d)	845	203	435	1,483
NGLs (bbl/d)	1,039	15	188	1,241
Total (boe/d)	**6,672**	**756**	**1,818**	**9,246**
Natural gas sales weighting	***72%***	***71%***	***66%***	***71%***

Second quarter average production was 9,246 boe/d (71% natural gas) in 2018 compared to 10,240 boe/d (69% natural gas) in the second quarter of 2017. The 10% decrease is attributable to certain production volume in the Foothills area being shut-in due to uneconomic natural gas pricing.

Capital Development [(1)]

The Company achieved year over year annual average production growth of 24% from 2016 to 2017 as a result of Petrus' strategic focus on its Ferrier production growth. However, in response to the current commodity price outlook for natural gas, the Company shifted its 2018 focus to prioritize light oil drilling opportunities and to direct excess funds flow towards debt repayment. To date in 2018, Petrus has drilled or participated in 2 (0.7 net) Cardium light oil wells in Ferrier and has reduced net debt by $13.0 million or 9%. The Company's 2018 capital program is scheduled to recommence in August and Petrus expects to drill an additional 7 (3.7 net) Cardium light oil wells during the second half of 2018.

[(1)] *Refer to "Advisories - Forward-Looking Statements"in the Management's Discussion & Analysis attached hereto.*

RESULTS OF OPERATIONS

FINANCIAL AND OPERATIONAL RESULTS OF OIL AND NATURAL GAS ACTIVITIES

	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Three months ended Mar. 31, 2018	Three months ended Dec. 31, 2017	Three months ended Sept. 30, 2017
Average production					
Natural gas (mcf/d)	39,126	42,392	45,543	46,625	45,550
Oil (bbl/d)	1,484	2,015	1,530	1,854	1,877
NGLs (bbl/d)	1,241	1,160	1,475	1,086	1,098
Total (boe/d)	**9,246**	**10,240**	**10,596**	**10,711**	**10,567**
Total (boe)	**841,316**	**931,821**	**953,598**	**985,388**	**972,140**
Revenue ($000s)					
Natural Gas	4,432	12,708	8,918	8,149	6,939
Oil	10,159	10,822	10,175	11,273	8,848
NGLs	4,692	3,199	6,175	3,796	2,504
Royalty revenue	38	24	33	25	8
Oil and natural gas revenue	**19,321**	**26,753**	**25,301**	**23,243**	**18,299**
Average realized prices					
Natural gas ($/mcf)	1.24	3.29	2.18	1.90	1.66
Oil ($/bbl)	75.29	59.02	73.91	66.10	51.23
NGLs ($/bbl)	41.53	30.32	46.50	38.00	24.79
Total realized price ($/boe)	22.92	28.69	26.50	23.56	18.82
Hedging gain (loss) ($/boe)	(0.74)	0.23	0.31	1.23	1.88
Total price including hedging ($/boe)	**22.18**	**28.92**	**26.81**	**24.79**	**20.70**

Average benchmark prices	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Three months ended Mar. 31, 2018	Three months ended Dec. 31, 2017	Three months ended Sept. 30, 2017
Natural gas					
AECO 5A ($/GJ)	1.12	2.57	1.97	1.60	1.38
AECO 7A ($/GJ)	0.97	2.63	1.76	1.86	1.93
Crude Oil					
Edm Lt. ($/bbl)	78.91	60.36	72.28	66.93	57.08
Foreign Exchange					
US$/C$	0.78	0.74	0.80	0.78	0.80

FUNDS FLOW AND NET INCOME (LOSS)

Petrus generated funds flow of $8.4 million in the second quarter of 2018, a 33% decrease relative to the $12.5 million generated in the second quarter of 2017. The decrease is due to 10% lower production and 63% lower natural gas pricing (AECO 7A monthly index) partially offset by commodity hedging contracts in place. On a six month basis, funds flow was $20.5 million compared to $24.2 million in the prior year. The 15% decrease is due to 51% lower natural gas pricing (AECO 7A monthly index), offset by 10% lower operating expenses and 21% higher light oil pricing (Edm CAD$).

Petrus reported a net loss of $10.6 million in the second quarter of 2018, compared to a net loss of $0.8 million in the second quarter of the prior year. The higher net loss is due to accounting for the unrealized, non-cash, mark to market of the Company's risk management contracts. In the second quarter of 2018, Petrus recorded an $8.3 million unrealized hedging loss on financial derivatives whereas in the second quarter of 2017 a $0.4 million unrealized hedging gain on financial derivatives was recorded. On a six month basis, the Company generated net income of $6.5 million for the six months ended June 30, 2017 compared to a net loss of $16.3 million for the six months ended June 30, 2018. The accounting for the unrealized hedging on financial derivatives had a material impact on the earnings; in 2017 the Company recognized an unrealized gain of $8.4 million whereas in 2018 a $13.9 unrealized loss was recorded. The differences are due to changes in commodity prices at June 30 of the respective years.

($000s except per share)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Funds flow	**8,364**	**12,458**	**20,469**	**24,190**
Funds flow per share - basic	0.17	0.25	0.41	0.49
Funds flow per share - fully diluted	0.17	0.25	0.41	0.49
Net income (loss)	**(10,615)**	**(781)**	**(16,299)**	**6,530**
Net income (loss) per share - basic	(0.21)	(0.02)	(0.33)	0.14
Net income (loss) per share - fully diluted	(0.21)	(0.02)	(0.33)	0.14
Common shares outstanding (000s)				
Basic	49,492	49,428	49,492	49,428
Fully diluted	49,492	49,428	49,492	49,429
Weighted average shares outstanding (000s)				
Basic	49,492	49,428	49,492	48,098
Fully diluted	49,492	49,428	49,492	48,140

OIL AND NATURAL GAS REVENUE

Average production for the second quarter of 2018 was 9,246 boe/d (71% natural gas), 10% lower than the 10,240 boe/d (69% natural gas) average production for the second quarter of the prior year. The decrease is attributable to uneconomic dry gas production currently shut-in in the Company's Foothills area as a result of the low natural gas price environment. Total oil and natural gas revenue for the second quarter of 2018 decreased from $26.8 million in 2017 to $19.3 million in 2018. The 28% decrease is due to lower production and lower natural gas pricing.

Average production for the first six months of 2018 was 9,918 boe per day (71% natural gas), compared to 9,788 boe per day (70% natural gas) for the prior year comparative period. Total oil and natural gas revenue decreased from $49.0 million in the first six months of 2017 to $44.6 million in the six months ended June 30, 2018 mainly due to lower natural gas pricing.

Natural gas

During the three and six months ended June 30, 2018, the average benchmark natural gas price in Canada (AECO 7A monthly index) decreased by 63% and 50%, respectively, from the prior year comparative periods (average price of $1.03 per mcf in the second quarter of 2018 compared to $2.77 per mcf in the second quarter of the prior year, and $1.44 per mcf for the first six months of 2018, compared to $2.86 per mcf for the prior year comparative period).

The Company's average realized natural gas price during the second quarter of 2018 was $1.24 per mcf, compared to $3.29 per mcf in the second quarter of 2017, which represents a 62% decrease. Natural gas revenue for the second quarter of 2018 was $4.4 million and production of 3,560,488 mcf accounting for approximately 71% of second quarter production volume and 23% of oil and natural gas revenue, compared to revenue of $12.7 million and production of 3,857,621 mcf accounting for approximately 69% of second quarter production volume and 48% of oil and natural gas revenue in the prior year comparative period. Natural gas revenue decreased from the prior year due to lower natural gas prices during the second quarter of 2018.

Natural gas revenue for the first six months of 2018 was $13.4 million and production of 7,659,369 mcf accounted for approximately 71% of production volume in the period and 30% of oil and natural gas revenue, compared to revenue of $23.1 million and production of 7,487,531 mcf for 70% of production volume and 39% of oil and natural gas revenue in the prior year comparative period. The decrease is due to decreased natural gas prices.

Crude oil and condensate

Edmonton Light Sweet crude oil prices increased 31% from the second quarter of 2017 to the second quarter of 2018 (an average price of $78.91 per bbl for the second quarter of 2018 compared to an average price of $60.36 per bbl for the prior year comparative period). Prices increased 21% from the first six months of 2017 to the first six months of 2018 ($75.60 per bbl in 2018 compared to an average of $62.56 per bbl in the prior year comparative period).

Similarly, the average realized price of Petrus' crude oil and condensate was $75.29 per bbl for the second quarter of 2018 compared to $59.02 per bbl for the same period in the prior year. Petrus' realized oil price was lower than the corresponding marker due to lower oil quality.

Oil and condensate revenue for the second quarter of 2018 was $10.2 million and production of 134,933 bbl accounted for approximately 16% of total production volume and 53% of oil and natural gas revenue, compared to revenue of $10.8 million and production of 183,352 bbl accounted for approximately 20% of total production volume and 40% of oil and natural gas revenue in the second quarter of the prior year.

Oil and condensate revenue for the first six months of 2018 was $20.3 million and production of 272,598 bbl accounted for approximately 15% of total production volume and 46% of oil and natural gas revenue, compared to revenue of $19.5 million and production of 322,121 for 18% of total production volume and 40% of oil and natural gas revenue in the first six months of the prior year.

Natural gas liquids (NGLs)

The Company's NGL production mix consists of ethane, propane, butane, pentane and sulphur. The pricing received for NGL production is based on the product mix, the fractionation process required and the demand for fractionation facilities. In the second quarter of 2018, the overall realized NGL price averaged $41.53 per bbl, compared to $30.32 per bbl in the prior year. The increase is attributed to improved commodity prices as well as a change in the composition of the Company's NGLs.

NGL revenue for the second quarter of 2018 was $4.7 million and production of 112,968 bbl accounted for approximately 13% of production volume and 24% of oil and natural gas revenue, compared to revenue of $3.2 million and production of 105,533 bbl accounted for approximately 11% of production volume and 12% of oil and natural gas revenue for the second quarter of the prior year.

NGL revenue for the first six months of 2018 was $10.9 million and production of 272,598 bbl accounted for approximately 15% of production volume and 24% of oil and natural gas revenue in the period, compared to revenue of $6.4 million and production of 201,524 bbl for 11% of production volume and 13% of oil and natural gas revenue in the first six months of the prior year.

ROYALTY EXPENSES

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

Royalty Expenses ($000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Crown	**334**	2,042	**2,509**	3,496
Percent of production revenue	**2%**	16%	**6%**	7%
Gross overriding	**1,803**	2,264	**4,302**	4,119
Total	**2,137**	**4,306**	**6,811**	**7,615**

Total royalty expense (net of royalty allowances and incentives) decreased from $4.3 million in the second quarter of 2017 to $2.1 million in the second quarter of 2018 primarily due to the change in the annual gas cost allowance ("GCA") adjustment. Each year during the second quarter, the Company receives information related to its GCA credits, which results in an annual adjustment recorded to adjust GCA received through the prior year. In addition, second quarter royalty expense in 2018 was lower than 2017 as a result of lower natural gas prices.

On a six month basis, total royalty expense (net of royalty allowances and incentives) decreased from $7.6 million in 2017 to $6.8 million in 2018. The decrease is due to lower natural gas prices.

Gross overriding royalties decreased from $2.3 million in the second quarter of 2017 to $1.8 million in the second quarter of 2018, due to lower natural gas prices. Gross overriding royalties increased from $4.1 million for the six months ended June 30, 2017 to $4.3 million for the six months ended June 30, 2018, due to additional wells being drilled on land with gross overriding royalty burdens.

RISK MANAGEMENT

The Company utilizes commodity contracts as a risk management technique to mitigate exposure to commodity price volatility, increase the certainty of cash flows from operating activities and protect acquisition and development economics. 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 June 30, 2018**	**Three months ended June 30, 2017**	**Six months ended June 30, 2018**	**Six months ended June 30, 2017**
Realized hedging gain (loss)	**(625)**	212	**(327)**	694
Unrealized hedging gain (loss)	**(8,323)**	376	**(13,863)**	8,424
Net gain (loss) on derivatives	**(8,948)**	**588**	**(14,190)**	**9,118**

The Company recognized a realized hedging loss of $0.6 million during the second quarter of 2018, compared to a $0.2 million gain realized in the same quarter of the prior year. The realized loss in the current period is due to higher crude oil prices offset by lower natural gas prices. The realized loss in the second quarter of 2018 decreased the Company's total realized price by $0.74 per boe, compared to the realized gain in the second quarter of the prior year, which increased the Company's total realized price by $0.23 per boe.

The Company recognized a realized hedging loss of $0.3 million during the six months ended June 30, 2018, compared to a $0.7 million gain realized in the same period of the prior year. The realized loss in the current year is due to strengthened oil prices.

The unrealized hedging loss of $8.3 million for the three months ended June 30, 2018 represents the change in the unrealized risk management net asset position during the quarter. The unrealized hedging loss of $13.9 million for the six months ended June 30, 2018 represents the change in the unrealized risk management net asset position during the first six months of 2018. This change is the 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. On June 30, 2018, the unrealized risk management net liability mark-to-market value was $11.8 million.

The Company's risk management contracts provide protection from significant changes in crude oil and natural gas commodity prices for 2018, 2019 and 2020. The Company endeavors to hedge approximately 50 to 70% of its forecast production for the following year, and approximately 30 to 50% 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 8 of the Company's interim consolidated financial statements as at and for the period ended June 30, 2018. The table below summarizes Petrus' average crude oil and natural gas hedged volumes. The average volume of oil hedged for the remainder of 2018 (2,025 bbl/d) represents 74% of second quarter total average liquids (oil and NGL) production. The 26,000 GJ/d of natural gas hedged for the remainder of 2018 represents 63% of second quarter average natural gas production.

The following table summarizes the average and minimum and maximum cap and floor prices for the 2018 to 2020 oil and natural gas contracts in place as at the date of this MD&A:

	2018					**2019**					**2020**				
	Q1	**Q2**	**Q3**	**Q4**	**Avg.(1)**	**Q1**	**Q2**	**Q3**	**Q4**	**Avg.(1)**	**Q1**	**Q2**	**Q3**	**Q4**	**Avg.(1)**
Oil hedged (bbl/d)	2,300	1,950	2,050	2,000	**2,075**	1,850	1,400	1,400	1,300	**1,488**	800	300	—	—	**550**
Avg. WTI cap price ($/bbl)	65.80	66.24	66.95	66.31	**66.31**	67.68	67.13	69.26	68.76	**68.16**	70.20	74.85	—	—	**71.47**
Avg. WTI floor price ($/bbl)	62.16	65.06	66.63	66.06	**64.89**	67.43	67.13	69.26	68.76	**68.08**	70.20	74.85	—	—	**71.47**
Natural gas hedged (GJ/d)	35,500	27,000	27,000	25,000	**28,625**	20,000	14,000	14,000	11,000	**14,000**	8,500	3,500	3,500	1,167	**4,167**
Avg. AECO 7A cap price ($/GJ)	2.77	2.26	2.26	2.36	**2.44**	2.48	1.73	1.73	1.73	**2.01**	1.73	1.58	1.58	1.58	**1.66**
Avg. AECO 7A floor price ($/GJ)	2.74	2.26	2.26	2.36	**2.43**	2.48	1.73	1.73	1.73	**2.01**	1.73	1.58	1.58	1.58	**1.66**

(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 ($000s)	**Three months ended June 30, 2018**	**Three months ended June 30, 2017**	**Six months ended June 30, 2018**	**Six months ended June 30, 2017**
Operating expense, net (1)	**3,841**	5,156	**8,001**	8,935
Operating expense, net ($/boe)	**4.57**	5.53	**4.46**	5.04

(1) Operating expense is presented net of processing income and overhead recoveries.

Operating expense (presented net of processing income and overhead recoveries) totaled $3.8 million for the second quarter of 2018, a 26% decrease from the $5.2 million recorded in the second quarter of the prior year. This change is attributable to the 10% decrease in production over the same time period as well as improved operating efficiencies. On a per boe basis, operating expense for the second quarter was 17% lower at $4.57 per boe in 2018 compared to $5.53 per boe in 2017. The decrease is due to Petrus' continued commitment to lower operating costs.

For the six months ended June 30, 2018, operating expense (presented net of processing income and overhead recoveries) totaled $8.0 million, an 11% decrease from the $8.9 million incurred in the comparable period of the prior year. The decrease is attributable to Petrus' improved operating cost structure and decreased activity related to well workover projects. During the first six months of 2017, Petrus incurred significantly higher non-routine workover expense, the majority of which was incurred in the Foothills operating area.

TRANSPORTATION EXPENSE

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

Transportation Expense ($000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Transportation expense	**988**	1,235	**2,185**	2,392
Transportation expense ($/boe)	**1.17**	1.32	**1.22**	1.35

Petrus pays commodity and demand charges for transporting its gas on various 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 $1.0 million or $1.17 per boe in the second quarter of 2018 ($1.2 million or $1.32 per boe for the prior year comparative period).

On a six month basis, transportation expense totaled $2.2 million, or $1.22 per boe, which is 9% and 10% lower, respectively, than the costs incurred ($2.4 million or $1.35 per boe) in the prior year comparative period.

Overall, transportation expense, total and on a per boe basis, was lower during the second quarter and for the first six months of 2018 than the prior year comparative periods due to decreased production and 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 ($000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Gross general and administrative expense	**1,749**	2,495	**4,158**	4,720
Capitalized general and administrative and overhead recoveries	**(377)**	(1,448)	**(1,356)**	(2,791)
General and administrative expense	**1,372**	**1,047**	**2,802**	**1,929**
General and administrative expense ($/boe)	**1.63**	**1.12**	**1.56**	**1.09**

The Company's general and administrative expense consisted of the following expenditures:

General and Administrative Expense ($000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Personnel, consultants and directors	**949**	1,562	**2,459**	2,974
Office costs	**665**	763	**1,143**	1,285
Regulatory and public company expenses	**135**	170	**556**	461
Capitalized general and administrative expense and overhead recoveries	**(377)**	(1,448)	**(1,356)**	(2,791)
General and administrative expense	**1,372**	**1,047**	**2,802**	**1,929**

Second quarter 2018 G&A expense totaled $1.4 million or $1.63 per boe, compared to $1.0 million or $1.12 per boe in the second quarter of 2017. The increase from the prior year is primarily due to higher capital overhead recoveries recognized in the prior year as a result of higher capital activity in 2017 compared to 2018.

On a six month basis, G&A expense for the period ending June 30, 2018 totaled $2.8 million or $1.56 per boe compared to $1.9 million or $1.09 per boe for the prior year comparative period. The increase in 2018 is primarily due to higher capital overhead recoveries recognized in the prior year as a result of higher capital activity in 2017 compared to 2018, partially offset by lower personnel costs in 2018.

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 June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Gross share-based compensation expense	**165**	194	**355**	335
Capitalized share-based compensation	**(66)**	(78)	**(142)**	(134)
Share-based compensation expense	**99**	**116**	**213**	**201**

Share-based compensation expense (net of capitalized portion) was $0.1 million for the second quarter of 2018, which is consistent with the $0.1 million recognized in the second quarter of the prior year.

On a six month basis, share-based compensation expense (net of capitalized portion) for the period ending June 30, 2018 was $0.2 million, which is also consistent with the prior year comparative period ($0.2 million).

FINANCE EXPENSE

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

Finance Expense ($000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Interest expense	**2,097**	1,807	**3,962**	3,543
Total cash finance expense	**2,097**	1,807	**3,962**	3,543
Deferred financing costs	**126**	—	**267**	—
Accretion on decommissioning obligations	**222**	246	**446**	484
Total finance expense	**2,445**	**2,053**	**4,675**	**4,027**

The Company incurred total finance expense of $2.4 million in the second quarter of 2018, comprised of $0.2 million of non-cash accretion of its decommissioning obligations and $2.1 million of cash interest expense and $0.1 million of deferred financing fees, both related to the Revolving Credit Facility and Term Loan (as defined herein). In the second quarter of 2017, the Company incurred total finance expense of $2.1 million, comprised of $0.2 million in non-cash accretion of its decommissioning obligation and $1.8 million cash interest expense.

The Company incurred total finance expense of $4.7 million for the six month period ending June 30, 2018, compared to $4.0 million for the prior year comparative period. The increase in 2018 is due to higher interest rates.

DEPLETION AND DEPRECIATION

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

Depletion and Depreciation Expense ($000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Depletion and depreciation expense	**10,494**	**13,314**	**22,113**	24,931
Depletion and depreciation expense ($/boe)	**12.47**	**14.29**	**12.32**	14.07

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 second quarter of 2018 of $10.5 million or $12.47 per boe, compared to the second quarter of 2017, when $13.3 million or $14.29 per boe was recorded. For the six month period ending June 30, 2018, the Company recorded $22.1 million or $12.32 per boe, compared to $24.9 million or $14.07 per boe for the prior year.

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 June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Weighted average Common Shares outstanding				
Basic	**49,492**	49,428	**49,492**	48,098
Fully diluted	**49,492**	49,428	**49,492**	48,140
Common Shares outstanding				
Basic	**49,492**	49,428	**49,492**	49,428
Fully diluted	**49,492**	49,428	**49,492**	49,429
Stock options outstanding	**2,934**	2,751	**2,934**	2,751
Performance warrants outstanding	**—**	86	**—**	86

At June 30, 2018, the Company had 49,491,840 Common Shares and 2,933,990 stock options outstanding. The Company issued 549,900 stock options on May 28, 2018 at an exercise price of $1.49.

The Company has a deferred share unit plan in place whereby it may issue deferred share units to directors of the Company. At June 30, 2018, 130,038 (December 31, 2017 – 130,038) deferred share units were issued and outstanding.

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2018, Petrus had two debt instruments outstanding. The first is a reserve-based, senior secured revolving credit facility with a syndicate of lenders, which is comprised of an operating facility and a syndicated term-out facility (together, the "Revolving Credit Facility" or "RCF"). The second is a subordinated secured term loan (the "Term Loan").

(a) Revolving Credit Facility

At June 30, 2018, the RCF was comprised of a $20 million operating facility and a $100 million syndicated term-out facility. Consent from the syndicate lenders and the Term Loan lender is required for total borrowings against the RCF exceeding $105 million. The syndicated term-out facility has a revolving period that ends May 31, 2019 at which time it will either be renewed or converted to a one-year term facility. The Company has provided collateral by way of a debenture over all of the present and after acquired property of the Company. In May 2018, Petrus completed the annual review of the RCF.The RCF syndicate of lenders agreed to maintain the Company's borrowing base of $120 million until June 30, 2018 after which time, the borrowing base will decrease to $110 million. Consent from the RCF syndicate of lenders and the Term Loan lender is required for total borrowings under the RCF to exceed $105 million.

At June 30, 2018, the Company had a $0.4 million letter of credit outstanding against the RCF (December 31, 2017 – $0.3 million) and had drawn $95.3 million against the RCF (December 31, 2017 – $0.3 million letter of credit and $97.6 million outstanding against the RCF).

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 majority lender consent. A decrease in the borrowing base could result in a reduction to the available credit under the RCF.

(b) Term Loan

At June 30, 2018, the Company had a $35 million (December 31, 2017 – $35 million) Term Loan outstanding (excluding $0.8 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 (CDOR) 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 6 of the Company's June 30, 2018 interim consolidated financial statements. The Company was in compliance with all financial covenants at June 30, 2018.

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 and risk management liabilities. The Company anticipates it will continue to have adequate liquidity to fund its financial liabilities through its future funds flow.

Typically the Company ensures that it has sufficient cash on demand to meet expected operational expenses for a normal period. To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on operated and non-operated projects to further manage capital expenditures. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th day of each month.

As at June 30, 2018, the Company had a working capital deficiency (excluding the risk management asset or liability) of $5.7 million, primarily related to the $11.7 million in accounts payable. The Company plans to address this working capital deficiency by using its funds flow and available credit facilities. The next scheduled borrowing base redetermination date for the RCF is on or before October 31, 2018. Petrus anticipates it will continue to have adequate liquidity to fund its financial liabilities through funds flow and available credit capacity from its RCF.

The following are the contractual maturities of financial liabilities as at June 30, 2018:

$000s	Total	< 1 year	1-5 years
Accounts payable	11,657	11,657	—
Risk management liability	11,839	7,858	3,981
Bank indebtedness and long term debt(1)	133,603	3,303	130,300
Total	**157,099**	**22,818**	**134,281**

(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
Corporate office lease	1,134	716	418	—
Firm service transportation	20,020	1,073	12,501	6,446
Total commitments	**21,154**	**1,789**	**12,919**	**6,446**

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 8 and 13 of the Company's June 30, 2018 interim consolidated financial statements.

CAPITAL EXPENDITURES

Capital expenditures (excluding acquisitions and dispositions) totaled $1.7 million in the second quarter of 2018, compared to $18.9 million in the second quarter of the prior year. For the six months ended June 30, 2018, Petrus invested $7.8 million compared to $37.8 million in the prior year. The decrease in capital spending is related to decreased capital activity as a result of lower natural gas commodity pricing. The following table shows capital expenditures for the reporting periods indicated. All capital is presented before decommissioning obligations.

Capital Expenditures ($000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Drill and complete	**869**	11,332	**3,292**	26,274
Oil and gas equipment	**551**	6,460	**2,182**	9,770
Land and lease	**27**	451	**1,493**	583
Office	**—**	92	**—**	128
Capitalized general and administrative	**298**	568	**830**	1,056
Total Capital Expenditures	**1,745**	**18,903**	**7,797**	**37,811**
Gross (net) wells spud	**1 (0.2)**	**3 (2.2)**	**2 (0.7)**	**11 (8.1)**

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

Acquisitions and Dispositions ($000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Acquisitions	**18**	—	**—**	8,818
Dispositions	**(287)**	—	**(387)**	—
Total Acquisitions and Dispositions	**(269)**	**—**	**(387)**	**8,818**

During the three and six months ended June 30, 2018, Petrus acquired other exploration and evaluation and petroleum and natural gas properties and equipment of $0.02 million and $1.3 million, respectively (three and six month periods ending June 30, 2017 were $Nil and $8.8 million, respectively). During the second quarter of 2018, Petrus divested non-core assets for approximately $0.3 million ($Nil in the prior year comparative periods).

SUMMARY OF QUARTERLY RESULTS

($000s unless otherwise noted)	Jun. 30, 2018	Mar. 31, 2018	Dec. 31, 2017	Sept. 30, 2017	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016	Sep. 30, 2016
Average Production								
Natural gas (mcf/d)	39,126	45,543	46,625	45,550	42,392	40,332	37,327	30,009
Oil (bbl/d)	1,484	1,530	1,854	1,877	2,015	1,542	1,452	1,419
NGLs (bbl/d)	1,241	1,475	1,086	1,098	1,160	1,067	922	680
Total (boe/d)	**9,246**	**10,596**	**10,711**	**10,567**	**10,240**	**9,331**	**8,595**	**7,100**
Total (boe)	**841,316**	**953,598**	**985,388**	**972,140**	**931,821**	**839,746**	**790,806**	**653,215**
Financial Results								
Oil and natural gas revenue	19,321	25,301	23,243	18,299	26,753	22,274	21,409	13,805
Royalty expense	(2,137)	(4,674)	(3,000)	(2,656)	(4,306)	(3,309)	(2,787)	(1,951)
Net oil and natural gas revenue	**17,184**	**20,627**	**20,243**	**15,643**	**22,447**	**18,965**	**18,622**	**11,854**
Transportation expense	(988)	(1,197)	(1,233)	(1,255)	(1,235)	(1,157)	(1,187)	(971)
Operating expense	(3,841)	(4,160)	(4,744)	(5,271)	(5,155)	(3,780)	(2,867)	(3,945)
Operating netback	**12,355**	**15,270**	**14,266**	**9,117**	**16,057**	**14,028**	**14,568**	**6,938**
Realized gain (loss) on derivatives	(625)	298	1,210	1,829	212	482	783	2,652
Other income	103	—	—	—	—	—	—	—
General & administrative expense	(1,372)	(1,430)	(266)	(1,059)	(1,047)	(882)	(2,991)	(1,107)
Cash finance expense	(2,097)	(1,865)	(1,515)	(1,936)	(1,807)	(1,736)	(2,043)	(2,512)
Decommissioning expenditures	—	(168)	(611)	(224)	(957)	(160)	(508)	(28)
Corporate netback	**8,364**	**12,105**	**13,084**	**7,727**	**12,458**	**11,732**	**9,809**	**5,943**
Oil and natural gas revenue	**19,321**	**25,301**	**23,243**	**18,299**	**26,753**	**22,274**	**21,409**	**13,805**
Per share - basic	0.39	0.51	0.47	0.37	0.54	0.48	0.47	0.30
Per share - fully diluted	0.39	0.51	0.47	0.37	0.54	0.47	0.47	0.30
Net income (loss)	**(10,615)**	**(5,684)**	**(67,095)**	**(50,696)**	**(781)**	**7,311**	**(11,842)**	**(4,702)**
Per share - basic	(0.21)	(0.11)	(1.36)	(1.03)	(0.02)	0.16	(0.26)	(0.10)
Per share - fully diluted	(0.21)	(0.11)	(1.36)	(1.03)	(0.02)	0.16	(0.26)	(0.10)
Common shares outstanding (000s)								
Basic	49,492	49,492	49,492	49,428	49,428	49,428	45,349	45,349
Fully diluted	49,492	49,492	49,492	49,428	49,428	52,664	45,349	45,349
Weighted avg. shares outstanding (000s)								
Basic	49,492	49,492	49,456	49,428	49,428	46,754	45,349	45,349
Fully diluted	49,492	49,492	49,456	49,428	49,428	46,989	45,349	45,349
Total assets	330,359	343,161	353,445	409,078	465,794	460,095	439,967	448,404
Net debt	**(135,111)**	**(142,238)**	**(148,066)**	**(137,531)**	**(137,069)**	**(130,624)**	**(124,915)**	**(124,310)**

The oil and natural gas exploration and production industry is cyclical in nature. Petrus' financial position, results of operations and cash flows are affected by commodity prices, exchange rates, Canadian price differentials and production levels. Petrus' average quarterly production increased from 7,100 boe/d in the third quarter of 2016 to 9,246 boe/d in the second quarter of 2018. The 30% production increase is attributable to the Company's drilling program in the Ferrier area.

Commodity price improvements enable higher reinvestment in exploration, development and acquisition activities in future periods 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 audited consolidated financial statements as at and for the year ended December 31, 2017.

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, 2017.

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 June 30, 2018.

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 April 1, 2018 and ending on June 30, 2018 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", "net debt" and "net debt to funds flow." 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 gas industry which is a useful supplemental measure to evaluate the specific operating performance by product at the oil and 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.

Corporate Netback

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

	Three months ended Jun. 30, 2018		Three months ended Jun. 30, 2017		Six months ended Jun. 30, 2018		Six months ended Jun. 30, 2017	
	$000s	$/boe	$000s	$/boe	$000s	$/boe	$000s	$/boe
Oil and natural gas revenue	19,321	22.97	26,753	28.72	44,622	24.86	49,027	27.67
Royalty expense	(2,137)	(2.54)	(4,306)	(4.62)	(6,811)	(3.79)	(7,615)	(4.30)
Net oil and natural gas revenue	**17,184**	**20.43**	**22,447**	**24.10**	**37,811**	**21.07**	**41,412**	**23.37**
Transportation expense	(988)	(1.17)	(1,235)	(1.32)	(2,185)	(1.22)	(2,392)	(1.35)
Operating expense	(3,841)	(4.57)	(5,155)	(5.53)	(8,001)	(4.46)	(8,935)	(5.04)
Operating netback	**12,355**	**14.69**	**16,057**	**17.25**	**27,625**	**15.39**	**30,085**	**16.98**
Realized gain (loss) on financial derivatives	(625)	(0.74)	212	0.23	(327)	(0.18)	694	0.39
Other income	103	0.12	—	—	103	0.06	—	—
General & administrative expense	(1,372)	(1.63)	(1,047)	(1.12)	(2,802)	(1.56)	(1,929)	(1.09)
Cash finance expense	(2,097)	(2.49)	(1,807)	(1.94)	(3,962)	(2.21)	(3,543)	(2.00)
Decommissioning expenditures	—	—	(957)	(1.03)	(168)	(0.19)	(1,117)	(0.63)
Corporate netback and funds flow	**8,364**	**9.95**	**12,458**	**13.39**	**20,469**	**11.31**	**24,190**	**13.65**

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) 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 June 30, 2018**	**As at December 31, 2017**
Current assets adjusted for unrealized financial instruments	**9,316**	13,042
Less: current liabilities adjusted for unrealized financial instruments	**(14,960)**	(29,201)
Less: long term debt	**(129,467)**	(131,907)
Net debt	**(135,111)**	**(148,066)**

Net Debt to Funds Flow

Net debt to funds flow is calculated as the period ending net debt divided by the trailing quarter funds flow (annualized).

OIL AND GAS DISCLOSURES

Our oil and gas reserves statement for the year ended December 31, 2017, 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.

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, 2017. 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, expectations regarding the focus of and timing of capital expenditures; Petrus' drilling program; expected debt repayment amounts; the performance characteristics of the Company's crude oil, NGL and natural gas properties including estimated production; crude oil, NGL and natural gas production levels and product mix; the availability of funds flow; sources of funding for capital expenditures; the use of funds flow and available credit facilities to address working capital deficiency; the growth of Petrus and the availability of the full amount of the revolving credit facility; the treatment of the revolving credit facility following the end of the revolving period; Petrus' ability to fund its financial liabilities; the size of, and future net revenues from, crude oil, NGL (natural gas liquids) and natural gas reserves; future prospects; expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; access to debt and equity markets; projections of market prices and costs; Petrus' future operating and financial results; 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.

These forward-looking statements are made as of the date of this MD&A and the Company disclaims any intent or obligation to update any forward-looking statements, 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*
boe/d	*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*

CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

(Presented in 000's of Canadian dollars)

As at	June 30, 2018	December 31, 2017
ASSETS		
Current		
Cash	—	24
Deposits and prepaid expenses	1,763	1,430
Accounts receivable *(note 13)*	7,553	11,588
Risk management asset *(note 8)*	—	2,163
Total current assets	**9,316**	**15,205**
Non-current		
Risk management asset *(note 8)*	—	572
Exploration and evaluation assets *(notes 3 and 4)*	43,955	43,197
Property, plant and equipment *(notes 3 and 5)*	277,088	294,471
Total assets	**330,359**	**353,445**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Bank indebtedness *(note 13)*	3,303	3,844
Accounts payable and accrued liabilities *(note 13)*	11,657	25,601
Risk management liability *(note 8)*	7,858	—
Total current liabilities	**22,818**	**29,445**
Non-current liabilities		
Long term debt *(note 6)*	129,467	131,907
Decommissioning obligation *(note 7)*	39,309	40,654
Risk management liability *(note 8)*	3,981	711
Total liabilities	**195,575**	**202,717**
Shareholders' equity		
Share capital *(note 9)*	430,119	430,119
Contributed surplus	8,035	7,680
Deficit	(303,370)	(287,071)
Total shareholders' equity	**134,784**	**150,728**
Total liabilities and shareholders' equity	**330,359**	**353,445**

Commitments (note 17)
See accompanying notes to the interim consolidated financial statements

Approved by the Board of Directors,

(signed) "Don T. Gray"

Don T. Gray
Chairman

(signed) "Donald Cormack"

Donald Cormack
Director

CONSOLIDATED STATEMENTS OF NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS) (UNAUDITED)

(Presented in 000's of Canadian dollars, except per share amounts)

	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Six months ended Jun. 30, 2018	Six months ended Jun. 30, 2017
REVENUE				
Oil and natural gas revenue *(note 19)*	**19,321**	**26,753**	**44,622**	**49,027**
Royalty expense	(2,137)	(4,306)	(6,811)	(7,615)
Net oil and natural gas revenue	**17,184**	**22,447**	**37,811**	**41,412**
Other income	103	—	103	—
Net gain (loss) on financial derivatives *(note 8)*	(8,948)	588	(14,190)	9,118
	8,339	**23,035**	**23,724**	**50,530**
EXPENSES				
Operating *(note 11)*	3,841	5,155	8,001	8,935
Transportation	988	1,235	2,185	2,392
General and administrative *(note 12)*	1,372	1,047	2,802	1,929
Share-based compensation *(note 9)*	99	116	213	201
Finance *(note 15)*	2,445	2,053	4,675	4,027
Exploration and evaluation *(note 4)*	142	896	426	1,585
Depletion and depreciation *(note 5)*	10,494	13,314	22,113	24,931
Gain on sale of assets *(note 3)*	(427)	—	(392)	—
Total expenses	**18,954**	**23,816**	**40,023**	**44,000**
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	**(10,615)**	**(781)**	**(16,299)**	**6,530**
Net income (loss) per common share Basic and diluted *(note 10)*	**(0.21)**	**(0.02)**	**(0.33)**	**0.14**

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (UNAUDITED)

(Presented in 000's of Canadian dollars)

	Share Capital	Contributed Surplus	Deficit	Total
Balance, December 31, 2016	**419,671**	**7,410**	**(175,810)**	**251,271**
Net income	—	—	6,530	6,530
Issuance of common shares	10,319	—	—	10,319
Share issue costs	(35)	—	—	(35)
Share-based compensation	—	335	—	335
Balance, June 30, 2017	**429,955**	**7,745**	**(169,280)**	**268,420**
Balance, December 31, 2017	**430,119**	**7,680**	**(287,071)**	**150,728**
Net loss	—	—	(16,299)	(16,299)
Share-based compensation	—	355	—	355
Balance, June 30, 2018	**430,119**	**8,035**	**(303,370)**	**134,784**

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(Presented in 000's of Canadian dollars)

	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Six months ended Jun. 30, 2018	Six months ended Jun. 30, 2017
OPERATING ACTIVITIES				
Net income (loss)	**(10,615)**	**(781)**	**(16,299)**	**6,530**
Adjust items not affecting cash:				
Share-based compensation *(note 9)*	99	116	213	201
Unrealized loss (gain) on financial derivatives (*note 8)*	8,323	(376)	13,863	(8,424)
Non-cash finance expenses *(note 15)*	348	246	713	484
Depletion and depreciation *(note 5)*	10,494	13,314	22,113	24,931
Exploration and evaluation expense *(note 4)*	142	896	426	1,585
Gain on sale of assets *(note 3)*	(427)	—	(392)	—
Decommissioning expenditures *(note 7)*	—	(957)	(168)	(1,117)
Funds flow	**8,364**	**12,458**	**20,469**	**24,190**
Change in operating non-cash working capital *(note 16)*	(582)	3,246	(5,215)	993
Cash flows from operating activities	**7,782**	**15,704**	**15,254**	**25,183**
FINANCING ACTIVITIES				
Issue of common shares *(note 9)*	—	—	—	10,319
Share issue costs *(note 9)*	—	—	—	(35)
Repayment of term loan	—	—	—	(7,000)
Issuance (repayment) of revolving credit facility	(3,200)	4,164	(2,300)	16,233
Increase (repayment) in bank indebtedness	(2,512)	1,855	(541)	1,855
Transaction costs on debt	(350)	(500)	(350)	(891)
Change in financing non-cash working capital *(note 16)*	175	(100)	302	(216)
Cash flows from (used in) financing activities	**(5,887)**	**5,419**	**(2,889)**	**20,265**
INVESTING ACTIVITIES				
Property and equipment (acquisitions) dispositions *(note 3)*	28	—	—	(8,818)
Exploration and evaluation asset (acquisitions) dispositions *(note 3)*	241	—	(92)	—
Exploration and evaluation asset expenditures *(note 4)*	(75)	(451)	(1,181)	(583)
Petroleum and natural gas property expenditures *(note 5)*	(1,671)	(18,346)	(6,136)	(37,076)
Other capital expenditures *(note 5)*	—	(106)	—	(152)
Change in investing non-cash working capital *(note 16)*	(419)	(5,171)	(4,980)	901
Cash flows (used in) investing activities	**(1,896)**	**(24,074)**	**(12,389)**	**(45,728)**
Decrease in cash	(1)	(2,951)	(24)	(280)
Cash, beginning of period	1	2,951	24	280
Cash, end of period	—	—	—	—
Cash interest paid	2,097	1,807	3,962	3,543

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

As at June 30, 2018 and for the three and six months ended June 30, 2018 and 2017

1. NATURE OF THE ORGANIZATION

Petrus Resources Ltd. (the “Company” or "Petrus") was incorporated under the laws of the Province of Alberta on November 25, 2015. The principal undertaking of Petrus is the investment in energy business-related assets. The operations of the Company consist of the acquisition, development, exploration and exploitation of these assets. These consolidated financial statements reflect only the Company’s proportionate interest in such activities and are comprised of the Company and its subsidiaries, Petrus Resources Corp. and Petrus Resources Inc.

The Company’s head office is located at 2400, 240 - 4th Avenue SW, Calgary, Alberta, Canada.

These interim consolidated financial statements, for the three and six months ended June 30, 2018 and prior year comparative periods, were approved by the Company’s Audit Committee and Board of Directors on August 8, 2018.

2. BASIS OF PRESENTATION

Statement of Compliance
These condensed interim consolidated financial statements have been prepared by management on a historical basis, except for certain financial instruments that have been measured at fair value. These condensed interim financial statements have been prepared in accordance with International Accounting Standard 34 “Interim Financial Reporting.” Certain information and disclosures normally included in the notes to the annual financial statements have been condensed. Accordingly, these condensed consolidated interim financial statements should be read in conjunction with the annual financial statements for the year ended December 31, 2017 which were prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”).

The preparation of these condensed interim consolidated financial statements requires the use of certain critical accounting estimates and also requires management to exercise judgment in applying the Company’s accounting policies. In preparing these condensed interim consolidated financial statements, the significant judgments made by management in applying the Company’s accounting policies and key sources of estimation uncertainty were the same as those applied to the financial statements for the year ended December 31, 2017. The condensed interim consolidated financial statements have been prepared following the same accounting policies as the financial statements for the year ended December 31, 2017, other than the new accounting policies adopted below. These condensed interim consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency, except where otherwise noted.

Significant accounting policies
The Company’s significant accounting policies can be read in note 3 to the Company’s audited consolidated financial statements as at and for the year ended December 31, 2017.

New standards and interpretations adopted on January 1, 2018
IFRS 9 Financial Instruments
On January 1, 2018, Petrus adopted IFRS 9 Financial Instruments, which includes a principle-based approach for classification and measurement of financial assets and a forward-looking ‘expected credit loss’ model. The classification and measurement of financial instruments under IFRS 9 did not have a material impact on Petrus’ consolidated financial statements. In addition, the application of the expected credit loss model to financial assets classified as amortized cost did not result in a material adjustment on transition.

IFRS 9 was applied retrospectively in accordance with transition requirements with no impact to opening retained earnings or comparative periods. Petrus has revised its accounting policy for financial instruments to reflect the new classification approach as follows:

Financial instruments
Financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, financial instruments are measured based on their classification as described below:

- Fair value through profit or loss: Financial instruments under this classification include risk management assets and liabilities.
- Amortized cost: Financial instruments under this classification include cash, accounts receivable, deposits, bank indebtedness, accounts payable and long term debt.

IFRS 15 Revenue from Contracts with Customers
Petrus adopted IFRS 15 "Revenue from Contracts with Customers" effective January 1, 2018, which establishes a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized. Petrus' revenue relates to the sale of petroleum and natural gas to customers at specified delivery points at benchmark prices. Petrus adopted IFRS 15 using the modified retrospective approach. Under this transitional provision, the cumulative effect of initially applying IFRS 15 is recognized on the date of initial application as an adjustment to retained earnings. No adjustment to retained earnings was required upon adoption of IFRS 15. The adoption of IFRS 15 did not materially impact the timing or measurement of revenue. However, IFRS 15 contains new disclosure requirements.

In addition, as a result of this adoption, Petrus has revised the description of its accounting policy for revenue recognition as follows:

Revenue recognition
Revenue from contracts with customers is recognized when or as Petrus satisfies a performance obligation by transferring a promised good or service to a customer. The transfer of control of oil, natural gas, natural gas liquids usually occurs at a point in time and coincides with title passing to the customer and the customer taking physical possession. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period.

IFRS 16 Leases
IFRS 16 was issued in January 2016 and it replaces IAS 17 Leases, IFRIC 4 Determining whether an Arrangement contains a Lease, SIC-15 Operating Leases-Incentives and SIC-27 Evaluating the Substance of Transactions Involving the Legal Form of a Lease. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases and requires lessees to account for all leases under a single on-balance sheet model similar to the accounting for finance leases under IAS 17. The standard includes two recognition exemptions for lessees – leases of 'low-value' assets (e.g., personal computers) and short-term leases (i.e., leases with a lease term of 12 months or less). At the commencement date of a lease, a lessee will recognize a liability to make lease payments (i.e., the lease liability) and an asset representing the right to use the underlying asset during the lease term (i.e., the right-of-use asset). Lessees will be required to separately recognize the interest expense on the lease liability and the depreciation expense on the right-of-use asset.

Lessees will be also required to remeasure the lease liability upon the occurrence of certain events (e.g., a change in the lease term, a change in future lease payments resulting from a change in an index or rate used to determine those payments). The lessee will generally recognize the amount of the remeasurement of the lease liability as an adjustment to the right-of-use asset.

IFRS 16 is effective for annual periods beginning on or after January 1, 2019. A lessee can choose to apply the standard using either a full retrospective or a modified retrospective approach. The standard's transition provisions permit certain reliefs. Petrus is currently assessing the potential effect of IFRS 16 on its consolidated financial statements.

3. ACQUISITIONS AND DISPOSITIONS

Asset exchange agreement
On March 13, 2018, Petrus closed a property swap transaction to exchange assets with an arm's length party. The Company recorded a loss of $0.1 million on the asset exchange, net of closing adjustments, during the six months ended June 30, 2018.

The following tables summarize the net assets disposed of and acquired pursuant to the swap:

Net assets disposed $000s	
Exploration and evaluation assets	1,086
Petroleum and natural gas properties and equipment	3,231
Decommissioning obligations	(471)
Total net assets disposed	**3,846**

Fair value of net assets acquired $000s	
Exploration and evaluation assets	1,013
Petroleum and natural gas properties and equipment	2,852
Decommissioning obligations	(224)
Total net assets acquired	**3,641**

During the six months ended June 30, 2018, Petrus incurred approximately $1.3 million in net cash expenditures on other minor acquisition and disposition transactions for petroleum and natural gas properties and equipment. During the six months ended June 30, 2018, the Company recorded a net gain of $0.4 million, net of approximately $0.1 in decommissioning obligation, from the disposition of exploration and evaluation assets and petroleum and natural gas properties for approximately $0.4 million.

Property disposition - non-core
On August 15, 2017 Petrus closed the disposition of its working interest in certain non-core oil and natural gas properties in the Company's Foothills area for cash consideration of $4.9 million. The assets disposed of included approximately 150 boe/d of production along with related land and infrastructure. The proceeds were utilized to repay indebtedness under the Company's credit facilities. The Company recorded a loss of $0.9 million related to the disposition during the year ended December 31, 2017.

The following table summarizes the net assets disposed pursuant to the disposition:

Net assets disposed $000s	
Exploration and evaluation assets	1,438
Petroleum and natural gas properties and equipment	5,579
Decommissioning obligations	(1,232)
Total net assets disposed	**5,785**

Property acquisition
On February 28, 2017 Petrus closed the acquisition of oil and natural gas assets for total cash consideration of $8.8 million net of closing adjustments. The acquisition included approximately 3,200 undeveloped Cardium leases in is Ferrier core area, approximately 40 boe/d of production and a non-producing well. The purchase price was allocated as follows:

Fair value of net assets acquired $000s	
Exploration and evaluation assets	8,000
Petroleum and natural gas properties and equipment	969
Decommissioning obligations	(151)
Total net assets acquired	**8,818**

Other acquisition and disposition activity
During 2017, Petrus recorded other minor acquisition and disposition transactions for petroleum and natural gas properties and equipment for total net cash consideration of $0.8 million.

4. EXPLORATION AND EVALUATION ASSETS

The components of the Company's exploration and evaluation assets are as follows:

$000s	
Balance, December 31, 2016	**64,824**
Additions	309
Property acquisitions *(note 3)*	8,000
Exploration and evaluation expense	(2,783)
Capitalized G&A	520
Capitalized share-based compensation	75
Property disposition *(note 3)*	(1,438)
Transfers to property, plant and equipment *(note 5)*	(7,036)
Impairment loss	(19,274)
Balance, December 31, 2017	**43,197**
Additions	960
Property acquisition *(note 3)*	402
Exploration and evaluation expense	(426)
Capitalized G&A	221
Capitalized share-based compensation *(note 9)*	36
Property disposition *(note 3)*	(53)
Transfers to property, plant and equipment *(note 5)*	(382)
Balance, June 30, 2018	**43,955**

For the three and six months ended June 30, 2018, the Company incurred exploration and evaluation expense of $0.1 million and $0.4 million, respectively, which relates to expired and near expiry undeveloped, non-core land (three and six months ended June 30, 2017 – $0.9 million and $1.6 million, respectively).

During the three and six months ended June 30, 2018, the Company capitalized $0.1 million and $0.2 million, respectively, of general and administrative expenses ("G&A") (three and six months ended June 30, 2017 – $0.1 million and $0.3 million, respectively) and $0.02 million and $0.04 million, respectively, of non-cash share-based compensation directly attributable to exploration activities (three and six months ended June 30, 2017 – $0.02 million and $0.03 million, respectively).

During the year ended December 31, 2017, management determined that certain CGUs were no longer considered to be core to the Company. As such, a process was initiated 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 and estimated the recoverable amounts of the Foothills exploration and evaluation assets to be $2.9 million and the Central Alberta exploration and evaluation assets to be $2.7 million as at December 31, 2017. The Company recorded an impairment loss of $19.3 million during the year ended December 31, 2017.

No indicators of impairment were identified for the three and six months ended June 30, 2018.

5. PROPERTY, PLANT AND EQUIPMENT

The components of the Company's property, plant and equipment assets are as follows:

$000s	Cost	Accumulated DD&A	Net book value
Balance, December 31, 2016	**714,009**	**(351,806)**	**362,203**
Additions	70,361	—	70,361
Property acquisitions *(note 3)*	1,729	—	1,729
Property (dispositions) *(note 3)*	(15,078)	9,320	(5,758)
Capitalized G&A	1,560	—	1,560
Capitalized share-based compensation	226	—	226
Transfers from exploration and evaluation assets *(note 4)*	7,036	—	7,036
Depletion & depreciation	—	(52,614)	(52,614)
Decrease in decommissioning provision *(note 7)*	(545)	—	(545)
Impairment loss	—	(89,727)	(89,727)
Balance, December 31, 2017	**779,298**	**(484,827)**	**294,471**
Additions	5,471	—	5,471
Property acquisitions *(note 3)*	2,935	—	2,935
Property dispositions *(note 3)*	(3,503)	—	(3,503)
Capitalized G&A	665	—	665
Capitalized share-based compensation *(note 9)*	107	—	107
Transfers from exploration and evaluation assets *(note 4)*	382	—	382
Depletion & depreciation	—	(22,113)	(22,113)
Decrease in decommissioning provision *(note 7)*	(1,327)	—	(1,327)
Balance, June 30, 2018	**784,028**	**(506,940)**	**277,088**

At June 30, 2018 , estimated future development costs of $283.0 million (December 31, 2017 – $283.0 million) associated with the development of the Company's proved plus probable undeveloped reserves were included with the costs subject to depletion. During the three and six months ended June 30, 2018, the Company capitalized $0.2 million and $0.7 million of general and administrative expenses ("G&A") (three and six months ended June 30, 2017 – $0.4 million and $0.8 million, respectively) and non-cash share-based compensation of $0.05 million and $0.1 million, respectively (three and six months ended June 30, 2017 – $0.06 million and $0.1 million, respectively), directly attributable to development activities.

For the year ended December 31, 2017, the Company recorded property, plant and equipment impairments of $89.7 million. At the end of the third quarter 2017, management determined that certain CGUs were no longer considered to be core to the Company. As such, a process was initiated 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 and estimated the recoverable amounts, net of decommissioning liabilities, of the Foothills property plant and equipment assets to be $11.3 million and the Central Alberta property plant and equipment assets to be $44.3 million.

No indicators of impairment were identified for the three and six months ended June 30, 2018.

6. DEBT

At June 30, 2018, Petrus had two debt instruments outstanding. The first is a reserve-based, senior secured revolving credit facility with a syndicate of lenders, which is comprised of an operating facility and a syndicated term-out facility (together, the "Revolving Credit Facility" or "RCF"). The second is a subordinated secured term loan (the "Term Loan").

(a) Revolving Credit Facility

At June 30, 2018, the Company's RCF was comprised of a $20 million operating facility and a $100 million syndicated term-out facility. In May 2018, Petrus completed the annual review of the RCF. The RCF syndicate of lenders agreed to maintain the Company's borrowing base of $120 million until June 30, 2018 after which time, the borrowing base will decrease to $110 million. Consent from the RCF syndicate of lenders and the Term Loan lender is required for total borrowings under the RCF to exceed $105 million.

The term out facility revolving period has been extended to May 31, 2019. At the end of the facility revolving period, the RCF will either be renewed or converted to a one-year term facility. The next scheduled borrowing base redetermination date for the RCF is on or before October 31, 2018. The Company has provided collateral by way of a debenture over all of the present and after acquired property of the Company.

At June 30, 2018, the Company had a $0.4 million letter of credit outstanding against the RCF (December 31, 2017 – $0.3 million) and had drawn $95.3 million against the RCF (December 31, 2017 – $97.6 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 majority lender consent. A decrease in the borrowing base could result in a reduction to the available credit under the RCF.

(b) Term Loan

At June 30, 2018 the Company had a $35 million (December 31, 2017 – $35 million) Term Loan outstanding (excluding $0.8 million of unamortized deferred financing costs), which is due October 8, 2020. The Term Loan bears interest that is due and payable monthly and accrues at a per annum rate of the (three-month) Canadian Dealer Offered Rate (CDOR) 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 Company's RCF and Term Loan are subject to certain financial covenants. For the financial covenants' definitions and calculation methodology refer to the Company's Audited Consolidated Financial Statements as at and for the year ended December 31, 2017.

The key financial covenants as at June 30, 2018 are summarized in the following table.

Financial Covenant Description	Required Ratio	As at June 30, 2018
Working Capital Ratio	Over 1.00	2.25
Proved Asset Coverage Ratio [1]	Over 1.25	2.40
PDP Asset Coverage Ratio [1]	Over 1.00	1.64
Debt to EBITDA Ratio	Under 3.50	2.60

[1] *Calculations are based upon the Company's December 31, 2017 reserve report evaluated by Sproule Associates Ltd.*

At June 30, 2018 the Company is in compliance with all financial covenants.

7. DECOMMISSIONING OBLIGATION

The decommissioning liability was estimated based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The estimated future cash flows have been discounted using an average risk free rate of 2.20 percent and an inflation rate of 2.00 percent (December 31, 2017 – 2.22 percent and 2.00 percent, respectively). Changes in estimates in 2017 and 2018 are due to the changes in the risk free rate and changes in the estimated future cash flow to reclaim the wells and facilities. The Company has estimated the net present value of the decommissioning obligations to be $39.3 million as at June 30, 2018 ($40.7 million at December 31, 2017). The undiscounted, uninflated total future liability at June 30, 2018 is $41.5 million ($43.1 million at December 31, 2017). The payments are expected to be incurred over the operating lives of the assets.

The following table reconciles the decommissioning liability:

$000s	
Balance, December 31, 2016	**43,243**
Property acquisitions	151
Property dispositions	(1,232)
Liabilities incurred	2,530
Liabilities settled	(1,952)
Change in estimates	(3,075)
Accretion expense	989
Balance, December 31, 2017	**40,654**
Property acquisitions *(note 3)*	224
Property disposition *(note 3)*	(580)
Liabilities incurred	60
Liabilities settled	(168)
Change in estimates	(1,327)
Accretion expense	446
Balance, June 30, 2018	**39,309**

8. FINANCIAL RISK MANAGEMENT

The Company utilizes commodity contracts as a risk management technique to mitigate exposure to commodity price volatility. The following table summarizes the financial derivative contracts Petrus had outstanding as at June 30, 2018:

Contract Period	Type	Total Daily Volume (GJ)	Average Price (CDN$/GJ)
Natural Gas Swaps			
Jul. 1, 2018 to Oct. 31, 2018	Fixed price	23,000	$2.31
Jul. 1, 2018 to Dec. 31, 2018	Fixed price	4,000	$2.03
Nov. 1, 2018 to Mar. 31, 2019	Fixed price	20,000	$2.52
Apr. 1, 2019 to Oct. 31, 2019	Fixed price	13,000	$1.75
Nov. 1, 2019 to Mar. 31, 2020	Fixed price	5,000	$1.84

Contract Period	Type	Total Daily Volume (Bbl)	Average Price (CDN$/Bbl)
Crude Oil Swaps			
Jul. 1, 2018 to Dec. 31, 2018	Fixed price	1,050	$64.09
Jul. 1, 2018 to Sep. 30, 2018	Fixed price	900	$70.32
Oct. 1, 2018 to Dec. 31, 2018	Fixed price	600	$72.23
Oct. 1, 2018 to Jun. 30, 2019	Fixed price	300	$61.60
Jan. 1, 2019 to Mar. 31, 2019	Fixed price	1,500	$68.84
Apr. 1, 2019 to Jun. 30, 2019	Fixed price	1,100	$68.64
Jul. 1, 2019 to Sep. 30, 2019	Fixed price	700	$70.94
Jul. 1, 2019 to Dec. 31, 2019	Fixed price	700	$67.59
Oct. 1, 2019 to Dec. 31, 2019	Fixed price	600	$70.13
Jan. 1, 2020 to Mar. 31, 2020	Fixed price	800	$70.20
Apr. 1, 2020 to Jun. 30, 2020	Fixed price	300	$74.85
Crude Oil Collars			
Jul. 1, 2018 to Sep. 30, 2018	Costless collar	100	$60.00-66.65
Oct. 1, 2018 to Dec. 31, 2018	Costless collar	50	$60.00-70.00
Jan. 1, 2019 to Mar. 31, 2019	Costless collar	50	$60.00-69.50

Risk management asset and liability:

$000s At June 30, 2018	Asset	Liability
Current commodity derivatives	—	7,858
Non-current commodity derivatives	—	3,981
	—	**11,839**

$000s At December 31, 2017	Asset	Liability
Current commodity derivatives	2,163	—
Non-current commodity derivatives	572	711
	2,735	**711**

Earnings impact of realized and unrealized gains (losses) on financial derivatives:

$000s	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Six months ended Jun. 30, 2018	Six months ended Jun. 30, 2017
Realized gain (loss) on financial derivatives	(625)	212	(327)	694
Unrealized gain (loss) on financial derivatives	(8,323)	376	(13,863)	8,424
Net gain (loss) on financial derivatives	**(8,948)**	**588**	**(14,190)**	**9,118**

Subsequent to June 30, 2018, the Company entered into the following financial derivative contracts:

Natural Gas Contract Period	Type	Daily Volume (GJ)	Price (CAD$/GJ)
Apr. 1, 2019 to Oct. 31, 2019	Fixed price	1,000	$1.37
Nov. 1, 2019 to Mar. 31, 2020	Fixed price	1,000	$1.79
Nov. 1, 2019 to Oct. 31, 2020	Fixed price	3,500	$1.58

9. SHARE CAPITAL

Authorized

The authorized share capital consists of an unlimited number of common voting shares without par value and an unlimited number of preferred shares.

Issued and Outstanding

Common shares ($000s *except number of shares*)	**Number of Shares**	**Amount**
Balance, December 31, 2016	**45,349,192**	**419,672**
Common shares issued under equity financing (a)	4,078,708	10,319
Common shares issued under the arrangement agreement	63,940	179
Share issue costs	—	(51)
Balance, December 31, 2017 and June 30, 2018	**49,491,840**	**430,119**

Share Issuances

(a) On February 28, 2017 the Company issued 4,078,708 common shares at a price of $2.53 per share through a non-brokered private placement.

SHARE-BASED COMPENSATION

Stock Options

The Company has a stock option plan in place whereby it may issue stock options to employees, consultants and directors of the Company. The aggregate number of shares that may be acquired upon exercise of all options granted pursuant to the plans shall, at any date or time of determination, be equal to ten percent (10%) of the number that is equal to (i) the number of the Company's basic common shares then issued and outstanding; minus (ii) a number equal to five (5) times the number of common shares that are issuable upon exercise of the then outstanding Performance Warrants minus (iii) a number equal to fifty percent (50%) of the number of common shares that have previously been issued upon the exercise of Performance Warrants.

At June 30, 2018, 2,933,991 (December 31, 2017 – 2,914,930) stock options were outstanding. The summary of stock option activity is presented below:

	Number of stock options	**Weighted average exercise price**
Balance, December 31, 2016	**1,976,580**	**$6.56**
Granted	1,855,200	$2.26
Exercised	(232,071)	$1.98
Forfeited or expired	(684,779)	$6.61
Balance, December 31, 2017	**2,914,930**	**$4.21**
Granted	549,900	$1.49
Forfeited or expired	(530,839)	$1.98
Balance, June 30, 2018	**2,933,991**	**$3.73**
Exercisable, June 30, 2018	**476,251**	**$12.48**

The following table summarizes information about the stock options granted since inception:

Range of Exercise Price	Stock Options Outstanding			Stock Options Exercisable		
	Number granted	Weighted average exercise price	Weighted average remaining life (years)	Number exercisable	Weighted average exercise price	Weighted average remaining life (years)
$1.49 - $2.33	2,457,740	$2.03	1.19	—	—	—
$9.00 - $16.00	476,251	$12.48	0.98	476,251	$12.48	0.98
	2,933,991	**$3.73**	**1.15**	**476,251**	**$12.48**	**0.98**

During the year ended December 31, 2017, the Company granted options which vest equally over three (3) years, and upon vesting, expire 30 business days thereafter. The weighted average fair value of each option granted in in 2018 of $0.42 (2017 – $0.64) was estimated on the date of grant using the Black-Scholes pricing model with the following weighted average assumptions:

	2018	2017
Risk free interest rate	0.80% - 1.90%	0.80% - 0.95%
Expected life (years)	1.08 - 3.08	1.08 - 3.08
Estimated volatility of underlying common shares (%)	63%	65%
Estimated forfeiture rate	20%	20%
Expected dividend yield (%)	0%	0%

Petrus estimated the volatility of the underlying common shares by analyzing the Company's volatility as well as the volatility of peer group public companies with similar corporate structure, oil and gas assets and size.

Deferred Share Unit ("DSU") Plan

The Company has a deferred share unit plan in place whereby it may issue deferred share units to directors of the Company. The aggregate number of shares that may be issued from treasury of Petrus pursuant to the plan shall not exceed: (i) five percent (5%) of the number of issued and outstanding common shares of the Company (on a non-diluted basis) at the date of issue; and (ii) ten percent (10%) of the number of issued and outstanding common shares of the Company (on a non-diluted basis) at the date of issue, less the aggregate number of common shares of the Company reserved for issuance under any other share compensation plan.

Each DSU entitles the participants to receive, at the Company's discretion, either shares of the Company or cash equal to the trading price of the equivalent number of shares of the Company. All DSUs granted vest and become payable upon retirement of the director.

The compensation expense was calculated using the fair value method based on the weighted average trading price of the Company's shares for the five trading days ending on the reporting period date. At June 30, 2018, 130,038 (December 31, 2017 – 130,038) Deferred Share Units were issued and outstanding.

The following table summarizes the change in accrued compensation liability related to DSUs:

$000s	
Balance, December 31, 2016	—
Change in accrued compensation liability	244
Balance, December 31, 2017	**244**
Change in accrued compensation liability	(113)
Balance, June 30, 2018	**131**

The following table summarizes the Company’s share-based compensation costs:

$000s	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Six months ended Jun. 30, 2018	Six months ended Jun. 30, 2017
Expensed	99	116	213	201
Capitalized to exploration and evaluation assets	17	19	36	33
Capitalized to property, plant and equipment	50	59	107	101
Total share-based compensation	**166**	**194**	**356**	**335**

10. EARNINGS (LOSS) PER SHARE

Earnings per share amounts are calculated by dividing the net income (loss) for the period attributable to the common shareholders of the Company by the weighted average number of common shares outstanding during the period.

	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Six months ended Jun. 30, 2018	Six months ended Jun. 30, 2017
Net income (loss) for the period ($000s)	**(10,615)**	**(781)**	**(16,299)**	**6,530**
Weighted average number of common shares – basic (000s)	49,492	49,428	49,492	48,098
Weighted average number of common shares – diluted (000s)	49,492	49,428	49,492	48,140
Net income (loss) per common share – basic	**($0.21)**	**($0.02) $**	**(0.33) $**	**0.14**
Net income (loss) per common share – diluted	**($0.21)**	**($0.02) $**	**(0.33) $**	**0.14**

In computing diluted earnings (loss) per share for the three and six months ended June 30, 2018, nil (June 30, 2017 – 86,000) warrants and 2,933,991 (three and six months ended June 30, 2017 – 2,751,070) outstanding stock options were considered. For the three and six months ended June 30, 2018 there were nil warrants and 2,933,991 stock options that were excluded from the calculation as their impact is anti-dilutive (three and six months ended June 30, 2017 – 86,000 and 1,995,400 respectively).

11. OPERATING EXPENSES

The Company's gross operating expenses for the three and six months ended June 30, 2018 were $4.1 million and $8.5 million, respectively (June 30, 2017 – $5.4 million and $9.4 million). For the three and six months ended June 30, 2018, this includes $1.0 million and $2.0 million of processing, gathering and compression charges (June 30, 2017 – $1.6 million and $2.6 million).

The Company generated processing income recoveries of $0.3 million and $0.5 million for the three and six months ended June 30, 2018 (June 30, 2017 – $0.3 million and $0.5 million), which reduced the Company's gross operating expenses to $3.8 million and $8.0 million for the three and six months ended June 30, 2018 (June 30, 2017 – $5.2 million and $8.9 million).

12. GENERAL AND ADMINISTRATIVE EXPENSES

The Company's general and administrative expenses consisted of the following expenditures:

$000s	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Six months ended Jun. 30, 2018	Six months ended Jun. 30, 2017
Personnel, consultants and directors	949	1,562	2,459	2,974
Office costs	665	763	1,143	1,285
Regulatory and public company expenses	135	170	556	461
Capitalized general and administrative expense and overhead	(377)	(1,448)	(1,356)	(2,791)
General and administrative expense	**1,372**	**1,047**	**2,802**	**1,929**

13. FINANCIAL INSTRUMENTS

Risks associated with financial instruments

Credit risk

The Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risk. Concentration of credit risk is mitigated by marketing the majority of the Company's production to reputable and financially sound purchasers under normal industry sale and payment terms. As is common in the petroleum and natural gas industry in western Canada, Petrus' receivables relating to the sale of petroleum and natural gas are received on or about the 25th day of the following month. Of the $7.6 million of accounts receivable outstanding at June 30, 2018 (December 31, 2017 – $11.6 million), $7.5 million is owed from 3 parties (December 31, 2017 – $8.7 million from 4 parties), and the balances were received subsequent to quarter end. The Company considers accounts receivable outstanding past 120 days to be 'past due'. At June 30, 2018, the Company had an allowance for doubtful accounts of $0.08 million (December 31, 2017 – $0.04 million). As at June 30, 2018, 99% of Petrus' accounts receivable were aged less than 120 days and 1% of Petrus' accounts receivable were aged greater than 120 days. The Company does not anticipate any significant collection issues.

The Company's risk management assets and cash are with chartered Canadian banks and the Company does not consider these assets to carry material credit risk.

Liquidity risk

At June 30, 2018, the Company had a $120 million RCF (lender consent is required for total borrowings against the RCF exceeding $105 million, see note 6), on which $95.3 million was drawn (December 31, 2017 – $97.6 million). While the Company is exposed to the risk of reductions to the borrowing base of the RCF, the Company anticipates it will continue to have adequate liquidity to fund its financial liabilities through funds flow and available credit capacity from its RCF. The next scheduled borrowing base redetermination date for the RCF is on or before October 31, 2018.

The following are the contractual maturities of financial liabilities as at June 30, 2018:

$000s	**Total**	**< 1 year**	**1-5 years**
Accounts payable	11,657	11,657	—
Risk management liability	11,839	7,858	3,981
Bank indebtedness and long term debt(1)	133,603	3,303	130,300
Total	**157,099**	**22,818**	**134,281**

(1)Excludes deferred finance fees.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company's cash, bank indebtedness and accounts receivable are not exposed to significant interest rate risk. The RCF and Term Loan are exposed to interest rate cash flow risk as the instruments are priced on a floating interest rate subject to fluctuations in market interest rates. The remainder of Petrus' financial assets and liabilities are not exposed to interest rate risk. A 1% increase in the Canadian prime interest rate during the three and six months ended June 30, 2018 would have increased net loss by approximately $1.3 million and $1.3 million, respectively, which relates to interest expense on the average outstanding RCF and Term Loan during the period assuming that all other variables remain constant (three and six months ended June 30, 2017 – decreased net income by $0.3 million and $0.6 million, respectively). A 1% decrease in the Canadian prime interest rate during the period would result in an opposite impact on net income (loss).

Commodity Price Risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. A significant change in commodity prices can materially impact the Company's borrowing base limit under its Revolving Credit Facility and may reduce the Company's ability to raise capital. Commodity prices for petroleum and natural gas are not only influenced by Canadian and United States demand, but also by world events that dictate the levels of supply and demand.

The Company manages the risks associated with changes in commodity prices by entering into a variety of financial derivative contracts (see note 8). The Company assesses the effects of movement in commodity prices on net loss. When assessing the potential impact of these commodity price changes, the Company believes a $5/CDN WTI/bbl change in the price of oil and a $0.25/GJ change in the price of natural gas are reasonable measures.

It is estimated that a $0.25/GJ decrease in the price of natural gas would have increased net loss for the three months ended June 30, 2018 by $2.5 million (three months ended June 30, 2017 – decreased net income by $2.9 million). An opposite change in commodity prices would result in an opposite impact on net income (loss). It is estimated that a $5.00/CDN WTI/bbl decrease in the price of oil would have increased net loss for the three months ended June 30, 2018 by $5.1 million (three months ended June 30, 2017 – decreased net income by $2.5 million). An opposite change in commodity prices would result in an opposite impact on net income (loss).

14. CAPITAL MANAGEMENT

The Company's general capital management policy is to maintain a sufficient capital base in order to manage its business to enable the Company to increase the value of its assets and therefore its underlying share value. In the management of capital, the Company includes share capital and total net debt, which is made up of debt and working capital (current assets less current liabilities). The Company manages its capital structure and makes adjustments in light of economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, Petrus may issue new equity, increase or decrease debt, adjust capital expenditures and acquire or dispose of assets.

15. FINANCE EXPENSES

The components of finance expenses are as follows:

$000s	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Six months ended Jun. 30, 2018	Six months ended Jun. 30, 2017
Cash:				
Interest	2,097	1,807	3,962	3,543
Non-cash:				
Deferred financing costs	126	—	267	—
Accretion on decommissioning obligations *(note 7)*	222	246	446	484
Total non-cash finance expenses	348	246	713	484
Total finance expenses	**2,445**	**2,053**	**4,675**	**4,027**

16. SUPPLEMENTAL CASH FLOW INFORMATION

The following table reconciles the changes in non-cash working capital as disclosed in the statements of cash flows:

$000s	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Six months ended Jun. 30, 2018	Six months ended Jun. 30, 2017
Source (use) in non-cash working capital:				
Deposits and prepaid expenses	(534)	(787)	(333)	(760)
Transaction costs on debt	350	—	350	—
Investments	—	—	—	—
Accounts receivable	2,123	(186)	4,035	710
Accounts payable and accrued liabilities	(2,766)	(1,052)	(13,944)	1,727
	(827)	**(2,025)**	**(9,892)**	**1,677**
Operating activities	(582)	3,246	(5,215)	993
Financing activities	175	(100)	302	(216)
Investing activities	(419)	(5,171)	(4,980)	901

The following table reconciles the changes in liability resulting from financing activities:

$000s	Bank Indebtedness	Revolving Credit Facility	Term Loan	Total Liabilities from Financing Activities
Balance, December 31, 2017	3,844	97,600	34,307	135,751
Cash flows	(541)	(2,300)	—	(2,841)
Non-cash changes	—	—	(139)	(139)
Balance, June 30, 2018	**3,303**	**95,300**	**34,168**	**132,771**

17. COMMITMENTS

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

$000s	Total	< 1 year	1-5 years	> 5 years
Corporate office lease	1,134	716	418	—
Firm service transportation	20,020	1,073	12,501	6,446
Total commitments	**21,154**	**1,789**	**12,919**	**6,446**

18. RELATED PARTY TRANSACTIONS

On February 28, 2017, the Chairman of the Company acquired 1,585,000 common shares ("Common Shares") of Petrus Resources Ltd. at a price of $2.53 per Common Share, pursuant to a non-brokered private placement of Common Shares (see note 9). The total consideration paid by the Chairman for the acquisition of the 1,585,000 Common Shares was $4,010,050.

19. REVENUE

The following table presents Petrus' oil and natural gas revenue disaggregated by product type:

$000s	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Six months ended Jun. 30, 2018	Six months ended Jun. 30, 2017
Production Revenue				
Oil and condensate sales	10,159	10,822	20,334	19,512
Natural gas sales	4,432	12,708	13,350	23,067
Natural gas liquids sales	4,692	3,199	10,867	6,385
Total oil and natural gas production revenue	**19,283**	**26,729**	**44,551**	**48,964**
Royalty revenue	38	24	71	63
Total oil and natural gas revenue	**19,321**	**26,753**	**44,622**	**49,027**

CORPORATE INFORMATION

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