Petrus Resources

ANNUAL REPORT

December 31, 2017

2017 HIGHLIGHTS

Petrus Resources Ltd. ("Petrus" or the "Company") (TSX: PRQ) is pleased to report financial and operating results for the three and twelve month periods ended December 31, 2017 and to provide summary 2017 year end reserves information as evaluated by Sproule Associates Limited ("Sproule"). The Company's Management's Discussion and Analysis ("MD&A") and audited consolidated financial statements dated as at and for the year ended December 31, 2017 are available on SEDAR (the System for Electronic Document Analysis and Retrieval) at www.sedar.com.

- Petrus generated funds flow of $45.0 million for the year ended December 31, 2017 which is 62% higher than the $27.8 million generated in the prior year. For the fourth quarter of 2017, Petrus generated funds flow of $13.1 million ($1.04 per share annualized), a 33% increase relative to the $9.8 million generated in the fourth quarter of 2016. The increases in funds flow are attributed to production growth and stronger oil and liquids pricing realized in 2017.

- Fourth quarter average production was 10,711 boe/d in 2017 compared to 8,595 boe/d in 2016. The 24% increase is attributable to the Company's drilling program at Ferrier, where production grew 54% during the same period. Since the third quarter of 2016, when the Company's quarterly average production was 7,100 boe/d, Petrus has grown its production 51%. Annual average production also increased 24% from 8,236 boe/d in 2016 to 10,217 boe/d in 2017. The production growth is a result of the Company's strategic shift to focus on developmental drilling and facility ownership and control in the Ferrier area.

- Operating expenses have decreased 22% from $6.48 per boe in the year ended December 31, 2016 to $5.08 per boe in the year ended December 31, 2017. The average annual expenses on a per boe basis have decreased due to the ownership, control and expansion of the Company's Ferrier gas plant, 2017 production growth, as well as the 2016 disposition of higher cost assets. The Company's operating expenses were $4.81 per boe in the fourth quarter of 2017.

- In 2017 Petrus' development program generated Proved Developed Producing ("PDP") reserve volume additions of 6.0 mmboe, or 43% of its December 31, 2016 PDP reserve volume of 13.8 mmboe. The Company produced 3.7 mmboe during 2017 and ended the year with 16.1 mmboe of PDP reserve volume.

- Petrus ended 2017 with $214.4 million and $485.1 million of PDP and Proved plus Probable ("P+P"), respectively, reserve value before-tax, discounted at 10%, based on the independent reserve report prepared by Sproule, dated March 7, 2018, for the year ended December 31, 2017 ("2017 Sproule Report"). The reserve values have increased 19% and 15%, respectively, from the December 31, 2016 Sproule Report. In 2017, the Company realized Finding and Development ("F&D") costs[3] of $11.57/boe and $12.03/boe for PDP and Total Proved ("TP") reserves, respectively, and during the year ended December 31, 2017 the Company's undeveloped net acreage in Ferrier grew 31%.

- During the fourth quarter of 2017, Petrus participated in 3 gross (1.4 net) Cardium wells in the Ferrier area, two of which were Cardium light oil wells and the third a Cardium gas well. The Ferrier gas plant expansion, doubling the plant's capacity from 30 mmcf/d to 60 mmcf/d, was completed in early October.

- Petrus utilizes financial derivative contracts to mitigate commodity price risk. The Company realized a gain on financial derivatives in the year ended December 31, 2017, which increased the Company's corporate netback[2] by $1.00 per boe. Petrus has derivative contracts in place for 58% (average floor price of $2.54 per mcf), and 68% (average floor price of $65.46 per bbl), of its natural gas and total liquids production, respectively, for the 2018 fiscal year (as a percentage of fourth quarter 2017 average production).

[1] *Refer to "Advisories - Forward-Looking Statements" in the Management's Discussion & Analysis attached hereto.*
[2] *Refer to "Non-GAAP Financial Measures" in the Management's Discussion & Analysis attached hereto.*
[3] *Refer to "Oil and Gas Disclosures" in the Management's Discussion & Analysis attached hereto.*

PRESIDENT'S MESSAGE

Looking back on 2017 we are proud of what we have accomplished this year, particularly in light of the challenges currently facing the Canadian energy market. In 2017 we made many strides in strengthening our business and in the last year we grew our production, reserves values, and funds flow, all on a per share basis. We reduced our operating costs and expanded both our undeveloped land holdings and future drilling inventory in our core Ferrier area. We have protected ourselves from volatile commodity prices with strong hedging contracts and are pursuing diversification in our commodity markets. We also continue to improve our capital efficiency as we add new production. Perhaps most importantly we continue to strive for further improvements in the following years.

In 2017, our funds flow per share was $0.92/share, up 51% from the previous year. Since the disposition of the Peace River property in the third quarter of 2016 we have grown our quarterly production by 51% to 10,711 boe/d, entirely by development drilling in Ferrier.

This year the value of our reserves increased in every category, highlighted by a Proved Developed Producing value growth of 19%. In 2017 we were able to add PDP reserves at an F&D cost of $11.57/boe. PDP reserve volume additions were 6.0 million boe, or 43% of our 2016 ending PDP volume. Our Ferrier asset provides us the ability to economically grow our reserves and per share value year after year.

During the year Petrus was able to add 31% to our Ferrier undeveloped land position and 48% to our future development inventory. At the rate we drilled in 2017, we now have more than a 17-year inventory in Ferrier alone, and we continue to expand that land base. Completion techniques have been rapidly improving which allows us to add production at record costs, highlighted by increased frac densities of up to 82 stages per section. And while many operational aspects of Petrus were growing, one notable metric was shrinking: our operating expenses which are now $4.81/boe.

For 2018 we've chosen to press pause on our production growth trajectory with the intent of improving our financial flexibility by reducing debt. Based on the current commodity price environment, our drilling will target Cardium oil locations which are offering payouts of less than 1 year, at current strip prices. We are excited about new completion techniques and increased frac densities which are adding materially to the initial production of recent wells, and also the economic returns. As evidenced by the achievements of the past year, we can resume our growth when market conditions permit. We are focused on continuously improving our business and I am excited to see what the next year will bring.

Neil Korchinski
President, Chief Executive Officer and Director

RESERVES

Petrus' 2017 year end reserves were evaluated by independent reserves evaluator Sproule Associates Limited ("Sproule") in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") as of December 31, 2017 ("2017 Sproule Report"). Additional reserve information as required under NI 51-101 will be included in our Annual Information Form, for the year ended December 31, 2017, which will be filed on SEDAR.

Petrus has a reserves committee, comprised of independent board members, that reviews the qualifications and appointment of the independent reserve evaluators. The committee also reviews the procedures for providing information to the evaluators. All booked reserves are based upon annual evaluations by the independent qualified reserve evaluators conducted in accordance with the COGE Handbook and NI 51-101. The evaluations are conducted using all available geological and engineering data. The reserves committee has reviewed the reserves information and approved the reserve report.

The following table provides a summary of the Company's before tax reserves as evaluated by Sproule:

As at December 31, 2017	**Total Company Interest** (1)(3)						
Reserve Category	**Conventional Natural Gas (mmcf)**	**Light and Medium Crude Oil (mbbl)**	**NGL (mbbl)**	**Total (mboe)**	**NPV 0%**(2) **($000s)**	**NPV 5%**(2) **($000s)**	**NPV 10%**(2) **($000s)**
Proved Producing	69,140	1,614	2,919	16,056	313,925	252,906	214,420
Proved Non-Producing	8,567	84	82	1,594	11,325	8,901	7,259
Proved Undeveloped	55,193	1,675	2,942	13,816	198,312	134,469	92,617
Total Proved	**132,900**	**3,372**	**5,943**	**31,465**	**523,561**	**396,276**	**314,296**
Proved + Probable Producing	88,692	2,181	3,667	20,630	429,640	317,865	257,025
Total Probable	**66,623**	**2,960**	**2,935**	**16,999**	**375,012**	**241,418**	**170,836**
Total Proved Plus Probable	**199,522**	**6,332**	**8,879**	**48,464**	**898,573**	**637,694**	**485,132**

(1) *Tables may not add due to rounding.*
(2) *NPV 0%, NPV 5% and NPV 10% refer to the risked net present value of the future net revenue of the Company's reserves, discounted by Nil, 5% and 10%, respectively and is presented before tax and based on Sproule's pricing assumptions.*
(3) *Total company interest reserve volumes are presented above and in the remainder of this annual report are presented as the Company's total working interest before the deduction of royalties (but after including any royalty interests of Petrus).*

In 2017 Petrus' development program generated Proved Developed Producing ("PDP") reserve volume additions of 6.0 mmboe, or 43% of its December 31, 2016 PDP reserve volume of 13.8 mmboe. The Company produced 3.7 mmboe during 2017 and ended the year with 16.1 mmboe of PDP reserve volume.

Petrus ended 2017 with $214.4 million and $485.1 million of PDP and Proved plus Probable ("P+P"), respectively, reserve value before-tax, discounted at 10%, based on the 2017 Sproule Report. The reserve values have increased 19% and 15%, respectively, from the independent reserve report prepared by Sproule for the year ended December 31, 2016. In 2017, the Company realized Finding and Development ("F&D") costs(3) of $11.57/boe and $12.03/boe for PDP and Total Proved ("TP") reserves, respectively, and during the year ended December 31, 2017 the Company's undeveloped net acreage in Ferrier grew 31%.

Based on the 2017 Sproule Report, the Company's PDP reserve value before-tax, discounted at 10% is $4.33 per share. On the same basis, the P+P reserve value is $9.80 per share.

FUTURE DEVELOPMENT COST

Future Development Cost ("FDC") reflects Sproule's best estimate of what it will cost to bring the P+P undeveloped reserves on production. FDC associated with Petrus' total P+P reserves at December 31, 2017, based on the 2017 Sproule Report, is $283.0 million (undiscounted) and includes 225 gross (122.4 net) booked P+P locations.

The following table provides a summary of the Company's FDC as set forth in the 2017 Sproule Report:

Future Development Cost ($000s)	Total Proved	Total Proved + Probable
2018	39,387	58,930
2019	57,309	96,528
2020	82,992	118,403
2021	2,397	9,169
Thereafter	—	—
Total FDC, Undiscounted	**182,086**	**283,030**
Total FDC, Discounted at 10%	**155,723**	**241,235**

PERFORMANCE RATIOS

The following table highlights annual performance ratios for the Company from 2014 to 2017:

	December 31, 2017	December 31, 2016	December 31, 2015	December 31, 2014
Proved Producing				
FD&A ($/boe) [(1)(2)]	**13.05**	(0.43)	23.18	35.35
Reserve Life Index (yr) [(1)]	**4.1**	4.4	5.2	4.6
Reserve Replacement Ratio [(1)]	**1.6**	0.4	0.7	5.9
Total Proved				
FD&A ($/boe) [(1)(2)]	**14.33**	(15.77)	16.77	27.44
Reserve Life Index (yr) [(1)]	**8.0**	9.8	10.9	7.3
Reserve Replacement Ratio [(1)]	**1.1**	0.5	2.9	9.1
Future Development Cost ($000s)	**182,086**	201,556	223,409	122,326
Total Proved + Probable				
FD&A ($/boe) [(1)(2)]	**14.87**	350.08	15.4	21.49
Reserve Life Index (yr) [(1)]	**12.3**	14.6	16.4	11.2
Reserve Replacement Ratio [(1)]	**1.7**	(0.1)	3.7	12.7
Future Development Cost ($000s)	**283,030**	269,144	325,325	199,410

(1) Refer to "Oil and Gas Disclosures in the Management's Discussion & Analysis attached hereto."
(2) Certain changes in FD&A produce non-meaningful figures as discussed in "Oil and Gas Disclosures" in the Management's Discussion & Analysis attached hereto.
While FD&A costs, reserve life index, reserve replacement ratio and finding and development costs are commonly used in the oil and nature gas industry and have been prepared by management, these terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies and, therefore, should not be used to make such comparisons.
FD&A costs take into account reserves revisions during the year on a per boe basis. The aggregate of the exploration and development costs incurred in the financial year and changes during that year in estimated future development costs generally will not reflect total FD&A costs related to reserves additions for that year.

In 2017, the Company realized F&D costs of $11.57/boe and $12.03/boe for PDP and TP reserves, respectively, as outlined in the following table.

Finding & Development Costs ($/boe) [(1)]	2017	2016
Proved Developed Producing [(1)]	**11.57**	**9.89**
Total Proved [(1)]	**12.03**	**2.46**
Proved Plus Probable [(1)]	**17.28**	**(8.06)**

(1) Refer to "Oil and Gas Disclosures" in the Management's Discussion & Analysis attached hereto.

NET ASSET VALUE

The following table shows the Company's Net Asset Value ("NAV"), calculated using the price forecast from Sproule Associates Limited, the Company's independent reserves evaluator:

As at December 31, 2017 ($000s except per share)	Proved Developed Producing	Total Proved	Proved and Probable
Present Value Reserves, before tax (discounted at 10%) [(1)]	214,420	314,296	485,132
Undeveloped Land Value [(2)]	43,197	43,197	43,197
Net Debt [(3)]	(148,066)	(148,066)	(148,066)
Net Asset Value	109,551	209,427	380,263
Fully Diluted Shares Outstanding [(4)]	49,492	49,492	49,492
Estimated Net Asset Value per Share	**$2.21**	**$4.23**	**$7.68**

[(1)] Based on the 2017 Sproule Report, using the forecast future prices and costs.
[(2)] Based on the exploration and evaluation assets as per the Company's December 31, 2017 audited consolidated financial statements.
[(3)] See Non-GAAP Financial Measures in the Management's Discussion & Analysis attached hereto.
[(4)] There were no "in-the-money" options or warrants based on the Company's December 31, 2017 closing share price of $1.95 therefore the calculation uses the common shares outstanding at December 31, 2017.

MANAGEMENT'S DISCUSSION & ANALYSIS

December 31, 2017

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 twelve month periods ended December 31, 2017. This MD&A is dated March 7, 2018 and should be read in conjunction with Petrus' audited consolidated financial statements for the years ended December 31, 2017 and 2016. 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 MD&A regarding "Forward-Looking Statements" and "BOE Presentation" and to the section "Non-GAAP Financial Measures" herein.

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

SELECTED FINANCIAL INFORMATION

OPERATIONS	Twelve months ended Dec. 31, 2017	Twelve months ended Dec. 31, 2016	Three months ended Dec. 31, 2017	Three months ended Sept. 30, 2017	Three months ended Jun. 30, 2017	Three months ended Mar. 31, 2017
Average Production						
Natural gas (mcf/d)	43,747	33,964	46,625	45,550	42,392	40,332
Oil (bbl/d)	1,823	1,820	1,854	1,877	2,015	1,542
NGLs (bbl/d)	1,103	755	1,086	1,098	1,160	1,067
Total (boe/d)	**10,217**	**8,236**	**10,711**	**10,567**	**10,240**	**9,331**
Total (boe)	**3,729,095**	**3,014,348**	**985,388**	**972,140**	**931,821**	**839,746**
Natural gas sales weighting	71%	69%	73%	72%	69%	72%
Realized Prices						
Natural gas ($/mcf)	2.39	2.39	1.90	1.66	3.29	2.85
Oil ($/bbl)	59.56	45.13	66.10	51.23	59.02	62.62
NGLs ($/bbl)	31.52	17.23	38.00	24.79	30.32	33.18
Total realized price ($/boe)	**24.26**	**21.40**	**23.56**	**18.82**	**28.69**	**26.48**
Royalty income	0.02	0.11	0.03	0.01	0.03	0.05
Royalty expense	(3.56)	(2.97)	(3.04)	(2.73)	(4.62)	(3.94)
Net oil and natural gas revenue ($/boe)	**20.72**	**18.54**	**20.55**	**16.10**	**24.10**	**22.59**
Operating expense	(5.08)	(6.48)	(4.81)	(5.42)	(5.53)	(4.50)
Transportation expense	(1.31)	(1.48)	(1.25)	(1.29)	(1.32)	(1.38)
Operating netback [1][2] ($/boe)	**14.33**	**10.58**	**14.49**	**9.39**	**17.25**	**16.71**
Realized gain on derivatives ($/boe) [2]	1.00	4.98	1.23	1.88	0.23	0.57
General & administrative expense	(0.87)	(2.56)	(0.27)	(1.09)	(1.12)	(1.05)
Cash finance expense	(1.88)	(3.53)	(1.54)	(1.99)	(1.94)	(2.07)
Decommissioning expenditures [3]	(0.52)	(0.96)	(0.62)	(0.23)	(1.03)	(0.19)
Corporate netback [1][2] ($/boe)	**12.06**	8.51	**13.29**	**7.96**	**13.39**	**13.97**

FINANCIAL (000s except per share)	Twelve months ended Dec. 31, 2017	Twelve months ended Dec. 31, 2016	Three months ended Dec. 31, 2017	Three months ended Sept. 30, 2017	Three months ended Jun. 30, 2017	Three months ended Mar. 31, 2017
Oil and natural gas revenue	90,569	64,840	23,243	18,299	26,753	22,274
Net income (loss)	(111,261)	(66,988)	(67,095)	(50,696)	(781)	7,311
Net income (loss) per share						
Basic	(2.28)	(1.51)	(1.36)	(1.03)	(0.02)	0.16
Fully diluted	(2.28)	(1.51)	(1.36)	(1.03)	(0.02)	0.16
Funds flow [3]	45,003	27,811	13,084	7,727	12,458	11,732
Funds flow per share [3]						
Basic	0.92	0.61	0.26	0.16	0.25	0.25
Fully diluted	0.92	0.61	0.26	0.16	0.25	0.25
Capital expenditures	72,750	29,246	21,885	13,055	18,903	18,907
Net acquisitions (dispositions)	4,741	(29,718)	789	(4,866)	—	8,818
Weighted average shares outstanding						
Basic	48,825	45,349	49,456	49,428	49,428	46,754
Fully diluted	48,825	45,349	49,456	49,428	49,428	46,989
As at period end						
Common shares outstanding						
Basic	49,492	45,349	49,492	49,428	49,428	49,428
Fully diluted	49,492	45,349	49,492	49,428	49,428	52,664
Total assets	353,445	439,967	353,445	409,078	465,794	460,095
Non-current liabilities	173,272	118,934	173,272	191,145	170,580	165,104
Net debt [1]	148,066	124,915	148,066	137,531	137,069	130,624

(1) *Refer to "Non-GAAP Financial Measures" in the Management's Discussion & Analysis attached hereto.*
(2) *In prior periods Petrus included realized gain on derivatives (hedging gain (loss)) in the calculation of operating netback. The amount is included in the calculation of corporate netback. The comparative information has been re-classified to conform to current presentation.*
(3) *In prior periods Petrus excluded decommissioning expenditures from the calculation of funds flow. The comparative information has been re-classified to conform to current presentation.*

OPERATIONS UPDATE

Production

Average fourth quarter production by area was as follows:

For the three months ended December 31, 2017	Ferrier	Foothills	Central Alberta	Total
Natural gas (mcf/d)	30,857	8,515	7,253	46,625
Oil (bbl/d)	1,212	222	420	1,854
NGLs (bbl/d)	904	36	146	1,086
Total (boe/d)	**7,259**	**1,677**	**1,775**	**10,711**
Natural gas sales weighting	***71%***	***85%***	***68%***	***73%***

Fourth quarter average production was 10,711 boe/d (73% natural gas) in 2017 compared to 8,595 boe/d (72% natural gas) in the fourth quarter of 2016. The 24% increase is attributable to the Company's drilling program in its core operating area, Ferrier, where production has grown 54% since the fourth quarter of 2016.

Capital Development

Petrus' 2017 drilling program has been focused exclusively in the Ferrier area targeting light oil and liquids rich natural gas in the Cardium formation. Throughout 2017, the Company drilled or participated in 19 gross (13.2 net) wells. This included two Extended Reach Horizontal ("ERH") liquids rich natural gas wells related to the previously announced Ferrier farm-in agreement ("Farm-In"), each with approximately 100 stages of fracture stimulations. One of these ERH wells came on production in November 2017, while the second ERH well was fracture stimulated and brought on production in December 2017. The Company estimates the Farm-in contributed 16 gross (5.2 net) Cardium locations to its drilling inventory(1). During the fourth quarter of 2017, Petrus participated in 3 gross (1.4 net) Cardium wells in the Ferrier area, two of which were light oil wells and the third a liquids rich natural gas well. The most recent Cardium oil well was fracture stimulated with 82 stages over a one mile lateral. This well flow tested over 1,200 bbl/d of oil over its 10 day test period.

During the fourth quarter of 2017, the Ferrier gas plant expansion was completed doubling the plant's capacity from 30 mmcf/d to 60 mmcf/d.

From 2015 to 2017 the Company has lowered its capital cost to add a producing barrel (which Petrus defines as the total capital investment per boe per day using the average initial production rate for the first 60 days) by 52%. This efficiency has dramatically improved as a result of increasing the frac density for the completion operations, using pad drilling to reduce capital costs, experiencing more efficient drilling times, implementing monobore wellbore design, and more efficient water management.

Commodity Pricing

During the third quarter of 2017, as a result of weakness and volatility in the Alberta natural gas commodity price market, Petrus realized high volatility in the market price for its natural gas. In particular, there was high volatility in the daily average natural gas spot price (AECO 5A index) which is the index on which Petrus previously sold all of its natural gas. Beginning in November 2017, Petrus elected for approximately half of its natural gas production to be paid on the forward monthly natural gas price (AECO 7A index) in an attempt to reduce the Company's exposure to daily natural gas price volatility.

During the fourth quarter of 2017, a lower portion of Petrus' natural gas production was sold on the daily average natural gas spot price (AECO 5A index). Furthermore, the AECO 5A index averaged $1.60 per GJ in the fourth quarter of 2017 which was 16% higher than the $1.38 per GJ average market price for the third quarter of 2017. Petrus' average realized natural gas price in the fourth quarter of 2017 of $1.80 per GJ was 12% higher than the AECO 5A index which averaged $1.60 per GJ in the fourth quarter of 2017.

Petrus has derivative contracts in place for 58% (average floor price of $2.54 per mcf), and 68% (average floor price of $65.46 per bbl), of its natural gas and total liquids production, respectively, for the 2018 fiscal year (as a percentage of fourth quarter 2017 average production).

Credit Review

In October 2017 Petrus completed the semi-annual review of its reserve based revolving credit facility ("RCF"). The RCF syndicate of lenders increased the borrowing base from $120 million to $130 million. In addition, the Company's total debt borrowing limit was increased from $141 million to $155 million. Petrus' Term Loan has $35 million outstanding therefore lender consent, from both the RCF syndicate and Petrus' Term Loan lender, is required for total borrowings against the RCF that exceed $105 million. The Company's annual review of its RCF is scheduled to take place in May 2018.

Outlook

Early in 2017 Petrus set out to grow its Ferrier production and as a result, set a 2017 capital budget of $50 to $60 million which was subsequently increased by $10 million to participate in additional capital opportunities identified. Petrus achieved year over year annual average production growth of 24% from 2016 to 2017. In response to the current commodity price outlook for natural gas, the Company has shifted its focus for 2018 to prioritize its light oil drilling opportunities and to moderate its growth in order to direct excess funds flow towards debt repayment. Petrus' Board of Directors has approved a 2018 capital budget of $25 to $30 million, with excess funds flow to be directed toward debt repayment. Petrus estimates debt repayment between $10 and $15 million in 2018, based on a current forecast for commodity futures pricing, anticipated service costs and current activity levels. Assuming capital investment of $25 million and a current forecast for commodity futures pricing, Petrus estimates the 2018 capital program will increase production year over year by 2% to an average annual 2018 production of approximately 10,350 boe/d. The 2018 capital is expected to be directed primarily to the development of the Company's Ferrier Cardium asset which is comprised of light oil and liquids rich natural gas opportunities. The program is expected to include the drilling of nine gross (4.4 net) Cardium wells and Petrus is focusing on the areas within the reservoir that are expected to be concentrated with light oil and condensate rich natural gas. The 2018 capital program is expected to be funded through funds flow and working capital.

(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

	Twelve months ended Dec. 31, 2017	Twelve months ended Dec. 31, 2016	Three months ended Dec. 31, 2017	Three months ended Sept. 30, 2017	Three months ended Jun. 30, 2017	Three months ended Mar. 31, 2017
Average production						
Natural gas (mcf/d)	43,747	33,964	46,625	45,550	42,392	40,332
Oil (bbl/d)	1,823	1,820	1,854	1,877	2,015	1,542
NGLs (bbl/d)	1,103	755	1,086	1,098	1,160	1,067
Total (boe/d)	**10,217**	**8,236**	**10,711**	**10,567**	**10,240**	**9,331**
Total (boe)	3,729,095	3,014,348	985,388	972,140	931,821	839,746
Revenue ($000s)						
Natural Gas	38,156	29,684	8,149	6,939	12,708	10,359
Oil	39,633	30,061	11,273	8,848	10,822	8,690
NGLs	12,685	4,763	3,796	2,504	3,199	3,186
Royalty revenue	95	332	25	8	24	39
Oil and natural gas revenue	90,569	64,840	23,243	18,299	26,753	22,274
Average realized prices						
Natural gas ($/mcf)	2.39	2.39	1.90	1.66	3.29	2.85
Oil ($/bbl)	59.56	45.13	66.10	51.23	59.02	62.62
NGLs ($/bbl)	31.52	17.23	38.00	24.79	30.32	33.18
Total ($/boe)	24.26	21.40	23.56	18.82	28.69	26.48
Hedging gain ($/boe)	1.00	4.98	1.23	1.88	0.23	0.57
Total realized ($/boe)	25.26	26.38	24.79	20.70	28.92	27.05

Average benchmark prices	Twelve months ended Dec. 31, 2017	Twelve months ended Dec. 31, 2016	Three months ended Dec. 31, 2017	Three months ended Sept. 30, 2017	Three months ended Jun. 30, 2017	Three months ended Mar. 31, 2017
Natural gas						
AECO 5A ($/GJ)	2.04	2.07	1.60	1.38	2.64	2.55
AECO 7A ($/GJ)	2.30	1.98	1.86	1.93	2.63	2.79
Crude Oil						
Edm Lt. ($/bbl)	62.28	52.82	66.93	57.08	60.36	64.76
Foreign Exchange						
US$/C$	0.77	0.75	0.78	0.80	0.74	0.76

FUNDS FLOW AND NET LOSS

Petrus generated funds flow of $13.1 million in the fourth quarter of 2017; an 33% increase relative to the $9.8 million generated in the fourth quarter of 2016. The increase is due to 24% higher production. On a twelve month basis, funds flow was 62% higher; $45.0 million in 2017 compared to $27.8 million in the prior year. The increase is due to 24% higher production and 22% lower operating expenses (on a per boe basis).

Petrus reported a net loss of $67.1 million in the fourth quarter of 2017, compared to a net loss of $4.7 million in the fourth quarter of the prior year. On a twelve month basis, the Company realized a net loss of $111.3 million in 2017 compared to a net loss of $67.0 million in the comparable period of 2016. The increase in net loss for the three and twelve month periods ended December 31, 2017 compared to the same periods in the prior year is mainly attributed to the impairment losses recorded in 2017 (see "Impairment" section in this MD&A).

($000s except per share)	Three months ended Dec. 31, 2017	Three months ended Dec. 31, 2016	Twelve months ended Dec. 31, 2017	Twelve months ended Dec. 31, 2016
Funds flow [1]	**13,084**	**9,809**	**45,003**	**27,811**
Funds flow per share - basic [1]	0.26	0.22	0.92	0.28
Funds flow per share - fully diluted [1]	0.26	0.22	0.92	0.28
Net loss	**(67,093)**	**(4,702)**	**(111,261)**	**(66,988)**
Net loss per share - basic	(1.36)	(0.10)	(2.28)	(1.51)
Net loss per share - fully diluted	(1.36)	(0.10)	(2.28)	(1.51)
Common shares outstanding (000s)				
Basic	49,492	45,349	49,492	45,349
Fully diluted	49,492	45,349	49,492	45,349
Weighted average shares outstanding (000s)				
Basic	49,456	45,349	48,825	44,429
Fully diluted	49,456	45,349	48,825	44,429

[1] *In prior periods Petrus excluded decommissioning expenditures from the calculation of funds flow. The comparative information has been re-classified to conform to current presentation.*

OIL AND NATURAL GAS REVENUE

Average production for the fourth quarter of 2017 was 10,711 boe/d (73% natural gas), 24% higher than the 8,595 boe/d (72% natural gas) average production for the fourth quarter of the prior year. The increase is attributable to the Company's drilling program at Ferrier which was funded by funds flow as well as utilization of the Company's revolving credit facility. Total oil and natural gas revenue for the fourth quarter increased from $21.4 million in 2016 to $23.2 million in 2017 which represents an 8% increase, due to higher production offset by lower realized commodity prices.

Average production for the year ended December 31, 2017 was 10,217 boe per day (71% natural gas), compared to 8,236 boe per day (67% natural gas) for the prior year, which represents a 24% increase. Total oil and natural gas revenue increased 39% from $64.8 million for the year ended December 31, 2016 to $90.6 million for the year ended December 31, 2017 due to increased production and improved oil prices.

Natural gas

During the three and twelve month periods ended December 31, 2017, the average benchmark natural gas price in Canada (AECO 5A) decreased by 45% and 2%, respectively, from prior year comparative periods (average price of $1.69 per mcf in the fourth quarter of 2017 compared to $3.09 per mcf in the fourth quarter of the prior year and $2.15 per mcf for the first twelve months of 2017, compared to $2.19 per mcf for the comparative period in 2016).

The Company’s average realized natural gas price during the fourth quarter of 2017 was $1.90 per mcf, compared to $3.29 per mcf in the fourth quarter of 2016, which represents a 34% decrease. Natural gas revenue for the fourth quarter of 2017 was $8.1 million and production of 4,289,475 mcf accounted for approximately 73% of fourth quarter production volume and 35% of oil and natural gas revenue (compared to revenue of $11.3 million and production of 2,760,858 mcf accounting for approximately 70% of fourth quarter production volume and 51% of commodity revenue in the prior year comparative period). Natural gas revenue for the fourth quarter of 2017 decreased from the prior comparable period due to lower natural gas prices realized during the fourth quarter of 2017 partially offset by continued growth in production in the Ferrier area.

Natural gas revenue for the year ended December 31, 2017 was $38.2 million and production of 15,967,547 mcf accounted for approximately 72% of production volume in the period and 42% of commodity revenue (compared to revenue of $29.7 million and production of 12,430,937 mcf accounting for approximately 69% of production volume and 46% of commodity revenue in 2016). The increase in natural gas revenue is due to increased production.

Crude oil and condensate

Edmonton Light Sweet crude oil prices increased 10% from the fourth quarter of 2016 to the fourth quarter of 2017 (an average price of $66.93 per bbl for the fourth quarter of 2017 compared to an average price of $60.70 per bbl for the prior year comparative period). Prices increased 18% for the year ended December 31, 2016 to the year ended December 31, 2017 ($62.28 per bbl in 2017 compared to an average of $52.82 per bbl in the prior year comparative period).

Similarly, the average realized price of Petrus' crude oil and condensate was $66.10 per bbl for the fourth quarter of 2017 compared to $45.13 per bbl for the same period in the prior year. Petrus' realized oil price was lower than the corresponding marker due to changes in oil quality and quantity, which resulted in changes in pricing differentials.

Oil and condensate revenue for the fourth quarter of 2017 was $11.3 million and production of 170,563 bbl accounted for approximately 17% of total production volume and 49% of oil and natural gas revenue, compared to revenue of $7.9 million and production of 133,603 bbl accounting for approximately 17% of total production volume and 37% of commodity revenue in the fourth quarter of the prior year.

Oil and condensate revenue for the year ended December 31, 2017 was $39.6 million and production of 665,390 bbl accounted for approximately 18% of total production volume and 44% of commodity revenue, compared to revenue of $30.1 million and production of 666,127 bbl accounting for approximately 22% of total production volume and 46% of oil and natural gas revenue for the year ended December 31, 2016.

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 fourth quarter of 2017, the overall realized NGL price averaged $38.00 per bbl, compared to $17.23 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 fourth quarter of 2017 was $3.8 million and production of 99,912 bbl accounted for approximately 10% of production volume and 16% of oil and natural gas revenue, compared to revenue of $2.1 million and production of 84,855 bbl accounting for approximately 11% of production volume and 10% of oil and natural gas revenue for the fourth quarter of the prior year. NGL revenue for the year ended December 31, 2017 was $12.7 million and production of 402,446 bbl accounted for approximately 11% of production volume and 14% of oil and natural gas revenue in the period, compared to revenue of $4.8 million and production of 276,398 bbl accounting for approximately 9% of production volume and 7% for the year ended December 31, 2016. The increase in NGL revenue is due to increased production and higher commodity prices.

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 December 31, 2017**	Three months ended December 31, 2016	**Twelve months ended December 31, 2017**	Twelve months ended December 31, 2016
Crown	**1,038**	1,920	**5,353**	3,901
% of production revenue	**4%**	9%	**6%**	6%
Gross overriding	**1,962**	1,230	**7,917**	5,046
Total	**3,000**	**3,150**	**13,270**	**8,947**

Total royalty expense (net of royalty allowances and incentives) decreased from $3.2 million in the fourth quarter of 2016 to $3.0 million in the fourth quarter of 2017. The decrease is attributable to lower natural gas pricing as well as higher gas cost allowance recorded in the fourth quarter of 2017. On a twelve month basis, total royalties paid increased from $8.9 million to $13.3 million. The increase was attributable to 24% higher production from the prior year. Total crown royalties were 6% of production revenue for both 2016 and 2017.

Gross overriding royalties increased from $1.2 million in the fourth quarter of 2016 to $2.0 million in the fourth quarter of 2017. Gross overriding royalties increased from $5.0 million for the twelve months ended December 31, 2016, to $7.9 million for the twelve months ended December 31, 2017. The increases in gross overriding royalties are 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. Petrus aims to hedge approximately 50 to 70% of its annual production forecast and approximately 30 to 40% of the following year production forecast.

The impact of the contracts that were outstanding during the reporting periods are actual cash settlements and are recorded as realized hedging gains (losses). These affect the Company's realized commodity price. 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 December 31, 2017**	Three months ended December 31, 2016	**Twelve months ended December 31, 2017**	Twelve months ended December 31, 2016
Realized hedging gain	**1,210**	783	**3,732**	15,002
Unrealized hedging gain (loss)	**(2,518)**	(9,225)	**9,621**	(21,531)
Net gain (loss) on derivatives	**(1,308)**	**(8,442)**	**13,353**	**(6,529)**

The Company recognized a realized hedging gain of $1.2 million during the fourth quarter of 2017, compared to a $0.8 million gain realized in the same quarter of the prior year. The higher realized gain in the current period is due to lower natural gas prices offset by strengthened crude oil prices. The fourth quarter realized gain increased the Company's total realized price by $1.23 per boe, compared to an increase of $0.99 per boe in the fourth quarter of the prior year.

The Company recognized a realized hedging gain of $3.7 million during the twelve months ended December 31, 2017, compared to a $15.0 million gain realized in the same period of the prior year. The lower gain in the current year is due to strengthened crude oil prices.

The unrealized hedging loss of $2.5 million for the three months ended December 31, 2017 represents the change in the unrealized risk management net asset position during the quarter. The unrealized hedging gain of $9.6 million for the twelve months ended December 31, 2017 represents the change in the unrealized risk management net asset position during 2017. The changes are 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 December 31, 2017, the unrealized risk management net asset mark-to-market value was $2.0 million.

The Company's risk management contracts provide protection from crude oil and natural gas prices in 2017, 2018 and 2019. For a complete listing of Petrus' risk management contracts see the Company's consolidated financial statements as at and for the period ended December 31, 2017 (note 10). The table below summarizes Petrus' average crude oil and natural gas hedged volumes. The 2,000 bbl/d of oil hedged for 2018 represents 68% of fourth quarter average liquids (oil and NGL) production. The 28,458 GJ/day of natural gas hedged for 2018 represents 58% of fourth quarter average natural gas production.

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

	2018					**2019**					**2020**	
	Q1	**Q2**	**Q3**	**Q4**	**Avg.**	**Q1**	**Q2**	**Q3**	**Q4**	**Avg.**	**Q1**	**Avg.**
Oil hedged (bbl/d)	2,300	1,950	1,850	1,900	**2,000**	1,350	1,100	1,000	800	**1,063**	400	**400**
Avg. WTI cap price ($/bbl)	65.80	66.24	66.81	65.69	**66.14**	62.39	63.25	64.83	63.46	**63.48**	67.10	**67.10**
Avg. WTI floor price ($/bbl)	62.16	65.06	66.45	65.42	**64.77**	62.03	63.25	64.83	63.46	**63.39**	67.10	**67.10**
Natural gas hedged (GJ/d)	35,500	27,000	27,000	24,333	**28,458**	19,000	10,000	10,000	3,333	**10,583**	—	—
Avg. AECO 7A cap price ($/GJ)	2.77	2.26	2.26	2.38	**2.42**	2.52	1.85	1.85	1.85	**2.01**	—	—
Avg. AECO 7A floor price ($/GJ)	2.74	2.26	2.26	2.38	**2.41**	2.52	1.85	1.85	1.85	**2.01**	—	—

OPERATING EXPENSE

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

Operating Expense ($000s)	**Three months ended December 31, 2017**	Three months ended December 31, 2016	**Twelve months ended December 31, 2017**	Twelve months ended December 31, 2016
Operating expense, net [(1)]	**4,744**	2,867	**18,950**	19,522
Operating expense, net ($/boe)	**4.81**	3.63	**5.08**	6.48

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

Operating expense (presented net of processing income and overhead recoveries) totaled $4.7 million for the fourth quarter of 2017, a 65% increase from the $2.9 million recorded in the fourth quarter of the prior year. The increase is attributable to the Company's 24% total production growth during the period. During the fourth quarter of 2017, Petrus incurred higher workover expenses in its other operating areas and a portion of Ferrier production was diverted through third party facilities prior to the completion of the Ferrier facility expansion. These contributed to 33% higher operating expenses, on a per boe basis, incurred in the fourth quarter of 2017 ($4.81 per boe) compared to the fourth quarter of 2016 ($3.63 per boe).

Operating expense (presented net of processing income and overhead recoveries) totaled $19.0 million for the year ended December 31, 2017, a 3% decrease from the $19.5 million recorded in the prior year, despite a 24% increase in production over the same period. Petrus has transformed its operating cost structure through the construction of a natural gas processing plant in Ferrier and the divestiture of higher cost assets. As a result, operating expenses per boe have decreased 21% from $6.48 per boe in the year ended December 31, 2016 to $5.08 per boe in the year ended December 31, 2017.

TRANSPORTATION EXPENSE

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

Transportation Expense ($000s)	Three months ended December 31, 2017	Three months ended December 31, 2016	Twelve months ended December 31, 2017	Twelve months ended December 31, 2016
Transportation expense	**1,233**	1,187	**4,880**	4,457
Transportation expense ($/boe)	**1.25**	1.50	**1.31**	1.48

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 $1.2 million or $1.25 per boe in the fourth quarter of 2017 ($1.2 million or $1.50 per boe for the prior year comparative period).

On a twelve month basis, transportation expense totaled $4.9 million, which is 12% higher than the $4.5 million incurred in the prior year comparative period. For the year ended December 31, 2017 transportation expense on a per boe basis was $1.31 per boe, decreasing 10% from $1.48 per boe in 2016.

Overall, total transportation expense was higher during the fourth quarter of 2017 than the prior year comparative period due to increased production and trucking costs. Transportation expense on a per boe basis was lower in the fourth quarter and during the year ended December 31, 2017 in comparison to the same prior year periods due to higher production volume and reduced transportation costs as firm service volume commitments were met.

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 ($000s)	Three months ended December 31, 2017	Three months ended December 31, 2016	Twelve months ended December 31, 2017	Twelve months ended December 31, 2016
Gross general and administrative expense	**1,681**	4,283	**8,787**	10,165
Capitalized general and administrative	**(412)**	(1,292)	**(2,082)**	(2,459)
Overhead recoveries	**(1,003)**	—	**(3,453)**	—
General and administrative expense	**266**	**2,991**	**3,252**	**7,706**
General and administrative ($/boe)	**0.27**	**3.78**	**0.87**	**2.56**

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

General and Administrative Expense ($000s)	Three months ended December 31, 2017	Three months ended December 31, 2016	Twelve months ended December 31, 2017	Twelve months ended December 31, 2016
Personnel, consultants and directors	**320**	3,285	**4,803**	6,593
Office costs	**835**	622	**2,929**	2,306
Regulatory and public company expenses	**526**	375	**1,055**	1,265
Capitalized general and administrative and overhead recoveries	**(1,415)**	(1,291)	**(5,535)**	(2,458)
General and administrative expense	**266**	**2,991**	**3,252**	**7,706**

Fourth quarter 2017 G&A expense totaled $0.3 million or $0.27 per boe, compared to $3.0 million or $3.78 per boe in the fourth quarter of 2016. The 91% decrease in total G&A expense for the fourth quarter 2017 was due to a decrease in the previously estimated annual incentive compensation. In addition, Petrus realized higher overhead recoveries due to increased capital development activity and did not incur significant transaction costs in 2017.

On a twelve month basis, G&A expense for the period ended December 31, 2017 totaled $3.3 million or $0.87 per boe compared to $7.7 million or $2.56 per boe for the prior year comparative period. The 58% decrease from 2016 to 2017 is attributed to a decrease in annual performance-based compensation, higher overhead recoveries and lower regulatory expenses, as well as higher transaction, compensation and severance costs incurred in the prior year. The higher overhead recoveries are attributed to increased capital activity. The Company's capital expenditures increased from $29.2 million for the year ended December 31, 2016 to $72.8 million for the year ended December 31, 2017.

FINANCE EXPENSE

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

Finance Expense ($000s)	Three months ended December 31, 2017	Three months ended December 31, 2016	Twelve months ended December 31, 2017	Twelve months ended December 31, 2016
Interest expense	**1,514**	2,043	**6,992**	10,587
Foreign exchange loss	**1**	—	**2**	50
Total cash finance expense	**1,515**	**2,043**	**6,994**	**10,637**
Deferred financing costs	**406**	—	**406**	—
Accretion on decommissioning obligations	**265**	47	**989**	973
Total finance expense	**2,186**	**2,090**	**8,389**	**11,610**

The Company incurred total finance expense of $2.2 million in the fourth quarter of 2017, comprised of $0.3 million of non-cash accretion of its decommissioning obligations, $0.4 million of deferred financing costs, and $1.5 million of cash interest expense related to its revolving credit facility and term loan. In the fourth quarter of 2016, the Company incurred total finance expense of $2.1 million, comprised of $0.05 million in non-cash accretion of its decommissioning obligations, $0.4 million of deferred financing costs, and $2.0 million cash interest expense.

On a twelve month basis, total finance expense decreased 28% from $11.6 million in 2016 to $8.4 million in 2017. The significant decrease in 2017 is due to lower debt outstanding as a result of financing proceeds and the Peace River asset disposition proceeds used to repay bank indebtedness.

DEPLETION AND DEPRECIATION

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

Depletion and Depreciation ($000s)	Three months ended December 31, 2017	Three months ended December 31, 2016	Twelve months ended December 31, 2017	Twelve months ended December 31, 2016
Depletion and depreciation expense	**12,654**	11,765	**52,614**	46,261
Depletion and depreciation ($/boe)	**12.84**	14.88	**14.11**	15.35

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 fourth quarter of 2017 of $12.7 million or $12.84 per boe, compared to the fourth quarter of 2016, when $11.8 million or $14.88 per boe was recorded. On a twelve month basis, the Company recorded $52.6 million or $14.11 per boe in 2017, compared to $46.3 million or $15.35 per boe for the prior year. The Company's depletion and depreciation expense decreased on a per boe basis from the prior year comparative periods due to higher production as a result of organic growth in the Ferrier area. In addition, the decrease is attributed to the disposition of the Peace River assets which had a higher depletion rate per boe.

IMPAIRMENT

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

Impairment ($000s)	Three months ended December 31, 2017	Three months ended December 31, 2016	Twelve months ended December 31, 2017	Twelve months ended December 31, 2016
Impairment	**64,000**	—	**109,000**	25,000
Total	**64,000**	**—**	**109,000**	**25,000**

Petrus recognized an impairment loss of $64.0 million and $109.0 million for the three and twelve month periods ended December 31, 2017, respectively, compared to the prior year comparative periods where an impairment loss of $nil and $25.0 million, respectively, was recorded.

During the year ended 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 in the Foothills and Central Alberta assets and information obtained through the divestiture process to date, the Company determined there were indicators of impairment. The Company recorded an impairment loss of $64.0 million and $109.0 million on its property, plant and equipment and exploration and evaluation assets related to the Foothills and Central Alberta CGUs during the three and twelve month periods ended December 31, 2017, respectively.

For the year ended December 31, 2017, the Company performed an impairment test for the Ferrier CGU, and no impairment charge was recorded as the recoverable amount of the Ferrier CGU was considerably higher than its carrying value. The recoverable amount of the Ferrier CGU was estimated at fair value less costs of disposal.

Petrus recorded an impairment loss of $25.0 million during the twelve months ended December 31, 2016 in conjunction with classification of certain assets located in the Peace River area of Alberta as assets held for sale. The disposition closed during the third quarter of 2016.

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 December 31, 2017**	Three months ended December 31, 2016	**Twelve months ended December 31, 2017**	Twelve months ended December 31, 2016
Weighted average common shares outstanding				
Basic	**49,456**	45,349	**48,825**	44,429
Fully diluted	**49,456**	45,349	**48,825**	44,429
Common shares outstanding				
Basic	**49,492**	45,349	**49,492**	45,349
Fully diluted	**49,492**	45,349	**49,492**	45,349
Stock options outstanding	**2,915**	1,977	**2,915**	1,977
Deferred share units outstanding	**130**	—	**130**	—
Performance warrants outstanding	**—**	430	**—**	430

At December 31, 2017, the Company had 49,491,840 Common Shares, 2,914,930 stock options and 130,038 deferred share units outstanding. During the fourth quarter of 2017 all remaining performance warrants expired and, therefore, none are outstanding at December 31, 2017. On February 28, 2017, the Company closed a non-brokered private placement of 4,078,708 Common Shares at a purchase price of $2.53 per Common Share, for aggregate gross proceeds of $10.3 million. The Chairman of the Company acquired 1,585,000 Common Shares at a price of $2.53 per Common Share, pursuant to the private placement (see note 11 of the Company's annual consolidated financial statements as at and for the year ended December 31, 2017). The total consideration paid by the Chairman for the acquisition of the 1,585,000 Common Shares was $4,010,050.

The Company issued a total of 1,855,200 stock options during the twelve months ended December 31, 2017 as follows:

(a) 999,900 stock options were issued on March 17, 2017 at an exercise price of $2.25.
(b) 450,000 stock options were issued on June 22, 2017 at an exercise price of $2.22.
(c) 21,000 stock options were issued on August 17, 2017 at an exercise price of $2.19.
(d) 384,300 stock options were issued on November 20, 2017 at an exercise price of $2.33.

The Company issued a total of 130,038 deferred share units during the twelve months ended December 31, 2017 as follows:

(a) 130,038 deferred share units were issued on October 17, 2017 at a fair value of $2.63.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2017, Petrus had two debt instruments outstanding. The first is a reserve-based, revolving credit facility with a syndicate of lenders. The total facility is comprised of an operating facility and a syndicated term-out facility (together, the "Revolving Credit Facility" or "RCF"). The second is a subordinated term loan (the "Term Loan").

(a) Revolving Credit Facility

At December 31, 2017, the Company's RCF was comprised of a $20 million operating facility and a $100 million syndicated term-out facility. Lender consent is required for total borrowings against the RCF exceeding $105 million. The term-out facility has a revolving period that ends May 31, 2018 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.

At December 31, 2017, the Company had a $0.3 million letter of credit outstanding against the RCF (December 31, 2016 – $0.3 million) and had drawn $97.6 million against the RCF (December 31, 2016 – $73.8 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 lender consent. A decrease in the borrowing base could result in a reduction to the available credit under the RCF.

(b) Term Loan

At December 31, 2017, the Company had a $35 million (December 31, 2016 – $42 million) Term Loan outstanding (excluding $0.7 million of deferred finance fees), which is due October 8, 2019. 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.

Covenants

The RCF and the Term Loan carry covenants that are described in note 8 of the Company's December 31, 2017 consolidated financial statements. The Company was in compliance with all covenants at December 31, 2017.

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 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 December 31, 2017, the Company had a working capital deficiency of $14.2 million, primarily related to the $25.6 million in accounts payable. The Company plans to address this working capital deficiency by using its funds flow and available credit facilities.

Petrus anticipates it will continue to have adequate liquidity to fund its financial liabilities through cash flows from operating activities and available credit capacity from its RCF. In addition, Petrus completed the semi-annual review of its revolving credit facility subsequent to the end of the third quarter, whereby the syndicate of lenders increased the borrowing base under the RCF from $120 to $130 million. In addition, the Company's total debt borrowing limit was increased from $141 million to $155 million. Petrus' Term Loan has $35 million outstanding therefore lender consent, from both the RCF syndicate and Petrus' Term Loan lender, is required for total borrowings against the RCF that exceed $105 million. The next scheduled borrowing base redetermination date for the RCF is on or before May 31, 2018. The Company believes that it will have adequate cash flows from operating activities to satisfy its financial liabilities with respect to its bank debt.

The following are the contractual maturities of financial liabilities as at December 31, 2017:

$000s	Total	< 1 year	1-5 years
Accounts payable	25,601	25,601	—
Risk management liability	711	0	711
Bank indebtedness and long term debt	135,751	3,844	131,907
Total	**162,063**	**29,445**	**132,618**

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

$000s	Total	< 1 year	1-5 years	> 5 years
Corporate office lease	1,491	716	775	—
Firm service transportation	20,074	1,042	11,228	7,804
Total commitments	**21,565**	**1,758**	**12,003**	**7,804**

Risk Management

Petrus is engaged in the development, acquisition, exploration and production 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 10 and 15 of the Company's December 31, 2017 consolidated financial statements.

CAPITAL EXPENDITURES

Capital expenditures (excluding acquisitions and dispositions) totaled $21.9 million in the fourth quarter of 2017, compared to $10.0 million in the fourth quarter of the prior year. For the year ended December 31, 2017, capital expenditures totaled $72.8 million compared to $29.2 million in 2016. The increase in capital spending in both the three and twelve month periods ended is related to increased capital activity, all in the Company's core operating area, Ferrier. During the year ended December 31, 2017, Petrus drilled or participated in 19 gross (13.2 net) wells (December 31, 2016 – 11 gross (7.3 net) wells). The Ferrier gas plant expansion, doubling the plant's capacity from 30 mmcf/d to 60 mmcf/d, was completed in early October. The following table shows capital expenditures for the reporting periods indicated. All capital is presented before decommissioning obligations.

Capital Expenditures ($000s)	**Three months ended December 31, 2017**	Three months ended December 31, 2016	**Twelve months ended December 31, 2017**	Twelve months ended December 31, 2016
Drill and complete	17,435	6,071	51,283	17,460
Oil and gas equipment	3,619	2,413	18,618	8,918
Geological	—	2	227	2
Land and lease	—	191	343	350
Other	105	—	197	—
Capitalized general and administrative	726	1,349	2,082	2,516
Total Capital Expenditures	**21,885**	**10,026**	**72,750**	**29,246**
Gross (net) wells spud	**3 (1.4)**	**5 (2.6)**	**19 (13.2)**	**11 (7.3)**

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.

On February 28, 2017, Petrus closed an acquisition of oil and natural gas interests in the Ferrier area for total consideration of $8.8 million after post-closing adjustments. Petrus acquired a minor amount of production as well as a 100% working interest in a drilled and completed Cardium horizontal well which had been tied in during the second quarter of 2017. In addition, Petrus acquired a 100% working interest in approximately 3,360 net acres (5.25 net sections) of undeveloped Cardium land in its Ferrier core area.

During 2017 Petrus also closed other minor property acquisitions in its core operating area Ferrier which totaled $0.8 million.

On July 8, 2016 Petrus closed the disposition of its oil and gas interests in the Peace River area of Alberta for total consideration of $29.4 million after post-closing adjustments, comprised of $28.4 million in cash and 1.0 million shares of the purchaser. Also during the third quarter of 2016, Petrus closed other dispositions of non-core exploration and evaluation assets and petroleum and natural gas properties and equipment for total cash consideration of $0.5 million.

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

Acquisitions and Dispositions ($000s)	**Three months ended December 31, 2017**	Three months ended December 31, 2016	**Twelve months ended December 31, 2017**	Twelve months ended December 31, 2016
Acquisitions	789	—	9,578	—
Dispositions	—	—	(4,837)	(29,717)
Total Acquisitions/(Dispositions)	**789**	**—**	**4,741**	**(29,717)**

SUMMARY OF QUARTERLY RESULTS

($000s unless otherwise noted)

For the three months ended,	Dec. 31, 2017	Sept. 30, 2017	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016
Average Production								
Natural gas (mcf/d)	46,625	45,550	42,392	40,332	37,327	30,009	33,071	35,456
Oil (bbl/d)	1,854	1,877	2,015	1,542	1,452	1,419	2,200	2,218
NGLs (bbl/d)	1,086	1,098	1,160	1,067	922	680	723	694
Total (boe/d)	**10,711**	**10,567**	**10,240**	**9,331**	**8,595**	**7,100**	**8,435**	**8,821**
Total (boe)	**985,388**	**972,140**	**931,821**	**839,746**	**790,806**	**653,215**	**767,585**	**802,744**
Financial Results								
Oil and natural gas revenue	23,243	18,299	26,753	22,274	21,409	13,805	14,926	14,698
Royalty expense [(1)]	(3,000)	(2,656)	(4,306)	(3,309)	(2,787)	(1,951)	(1,734)	(2,475)
Net oil and natural gas revenue	**20,243**	**15,643**	**22,447**	**18,965**	**18,622**	**11,854**	**13,192**	**12,223**
Transportation expense	(1,233)	(1,255)	(1,235)	(1,157)	(1,187)	(971)	(1,000)	(1,298)
Operating expense	(4,744)	(5,271)	(5,155)	(3,780)	(2,867)	(3,945)	(5,872)	(6,837)
Operating netback [(2)]	**14,266**	**9,117**	**16,057**	**14,028**	**14,568**	**6,938**	**6,320**	**4,088**
Realized gain on derivatives	1,210	1,829	212	482	783	2,652	5,273	6,294
General & administrative expense	(266)	(1,059)	(1,047)	(882)	(2,991)	(1,107)	(1,426)	(2,183)
Cash finance expense	(1,515)	(1,936)	(1,807)	(1,736)	(2,043)	(2,512)	(2,442)	(3,641)
Decommissioning expenditures	(611)	(224)	(957)	(160)	(508)	(28)	(74)	(146)
Corporate netback [(2)]	**13,084**	**7,727**	**12,458**	**11,732**	**9,809**	**5,943**	**7,651**	**4,412**
Oil and natural gas revenue	**23,243**	**18,299**	**26,753**	**22,274**	**21,409**	**13,805**	**14,926**	**14,698**
Per share - basic	0.47	0.37	0.54	0.48	0.47	0.30	0.33	0.35
Per share - fully diluted	0.47	0.37	0.54	0.47	0.47	0.30	0.33	0.35
Net income (loss)	**(67,095)**	**(50,696)**	**(781)**	**7,311**	**(11,842)**	**(4,702)**	**(46,334)**	**(4,110)**
Per share - basic	(1.36)	(1.03)	(0.02)	0.15	(0.26)	(0.10)	(1.02)	(0.10)
Per share - fully diluted	(1.36)	(1.03)	(0.02)	0.16	(0.26)	(0.10)	(1.02)	(0.10)
Common shares outstanding (000s)								
Basic	49,492	49,428	49,428	49,428	45,349	45,349	45,349	45,349
Fully diluted	49,492	49,428	49,428	52,664	45,349	45,349	45,349	45,349
Weighted avg. shares outstanding (000s)								
Basic	49,456	49,428	49,428	46,754	45,349	45,349	45,349	41,762
Fully diluted	49,456	49,428	49,428	46,989	45,349	45,349	45,349	41,762
Total assets	353,445	409,078	465,794	460,095	439,967	448,404	493,535	544,548
Net debt [(2)]	**(148,066)**	**(137,531)**	**(137,069)**	**(130,624)**	**(124,915)**	**(124,310)**	**(152,935)**	**(157,675)**

[(1)] *The Company re-classified gross overriding royalty expense from other income to royalty expenses in the Statement of Net Loss and Comprehensive Loss. The comparative information has been re-classified to conform to current presentation.*

[(2)] *See "Non-GAAP Financial Measures". Note in prior periods Petrus excluded decommissioning expenditures from the calculation of corporate netback. The comparative information has been re-classified to conform to current presentation.*

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 8,821 boe/d in the first quarter of 2016 to 10,711 boe/d in the fourth quarter of 2017. This 21% production increase is attributable to the Company's drilling program in the Ferrier area, partially offset by the disposition of the Company's assets in the Peace River area during the third quarter of 2016.

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.

SELECTED ANNUAL INFORMATION

($000s unless otherwise noted)

For the year ended,	December 31, 2017	December 31, 2016	December 31, 2015
Oil and natural gas revenue	**90,569**	**64,840**	**94,587**
Per share - basic	1.85	1.46	2.69
Per share - fully diluted	1.85	1.46	2.69
Net loss	**(111,261)**	**(66,988)**	**(69,031)**
Per share - basic	(2.28)	(1.51)	(1.96)
Per share - fully diluted	(2.28)	(1.51)	(1.96)
Total assets	**353,445**	**439,967**	**555,145**
Non-current liabilities	**173,272**	**118,934**	**169,357**

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 estimate 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 annual consolidated financial statements as at and for the year ended December 31, 2017.

Disclosure Controls and Procedures
Petrus' Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P"), as defined by National Instrument 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"), to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual 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 Chief Executive Officer and Chief Financial Officer of Petrus have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's DC&P as at December 31, 2017 and have concluded that the Company's DC&P are effective at December 31, 2017 for the foregoing purposes.

Internal Control over Financial Reporting
Internal control over financial reporting ("ICFR"), as defined in NI 52-109, includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of assets of Petrus; (ii) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of the consolidated financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Petrus are being made in accordance with authorizations of management and Directors of Petrus; and (iii) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the consolidated financial statements.

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for Petrus. For the year ended December 31, 2017, they have designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework used to design the Company's ICFR is the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, Petrus conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2017. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that as at December 31, 2017, Petrus maintained effective ICFR. It should be noted that while the Chief Executive Officer and Chief Financial Officer believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, a control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system will be met and it should not be expected that the control system 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 the GAAP and do not have a standardized meaning prescribed by GAAP. 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 Dec. 31, 2017		Three months ended Dec. 31, 2016		**Twelve months ended Dec. 31, 2017**		Twelve months ended Dec. 31, 2016	
	$000s	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**
Oil and natural gas revenue	23,243	23.59	21,409	27.07	90,569	24.28	64,840	19.53
Royalty expense	(3,000)	(3.04)	(2,787)	(3.52)	(13,270)	(3.56)	(8,947)	(2.77)
Net oil and natural gas revenue	**20,243**	**20.55**	**18,622**	**23.55**	**77,299**	**20.72**	**55,893**	**16.76**
Transportation expense	(1,233)	(1.25)	(1,187)	(1.50)	(4,880)	(1.31)	(4,457)	(1.47)
Operating expense	(4,744)	(4.81)	(2,867)	(3.63)	(18,950)	(5.08)	(19,522)	(7.49)
Operating netback	**14,266**	**14.49**	**14,568**	**18.42**	**53,469**	**14.33**	**31,914**	**7.80**
Realized gain on financial derivatives	1,210	1.23	783	0.99	3,732	1.00	15,002	4.98
General & administrative expense	(266)	(0.27)	(2,991)	(3.78)	(3,252)	(0.87)	(7,706)	(2.56)
Cash finance expense	(1,515)	(1.54)	(2,043)	(2.58)	(6,994)	(1.88)	(10,642)	(3.53)
Decommissioning expenditures	(611)	(0.62)	(508)	(0.64)	(1,952)	(0.52)	(757)	(0.25)
Corporate netback and funds flow	**13,084**	**13.29**	**9,809**	**12.41**	**45,003**	**12.06**	**27,811**	**6.44**

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 deferred share unit liabilities) and long term debt. Petrus uses net debt as a key indicator of its leverage and strength of its balance sheet. There is no GAAP measure that is reasonably comparable to net debt.

($000s)	**As at December 31, 2017**	As at December 31, 2016
Current assets adjusted for unrealized financial instruments	**13,042**	12,918
Less: current liabilities [(1)]	**(29,201)**	(64,066)
Less: long term debt	**(131,907)**	(73,767)
Net debt	**(148,066)**	**(124,915)**

[(1)] *Adjusted for unrealized risk management liabilities and unrealized deferred share units liabilities*

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 complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, is contained in the AIF for the year ended December 31, 2017 which will be available on our SEDAR profile at www.sedar.com. The recovery and reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered.

This MD&A contains metrics commonly used in the oil and natural gas industry, such as "finding and development costs" or "F&D", "finding, development and acquisition costs" or "FD&A", "future development cost" or "FDC", "reserve life index" and "reserve replacement ratio." These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included herein to provide readers with additional information to evaluate the Company's performance, however such metrics should not be unduly relied upon.

F&D and FD&A Costs

FD&A cost is defined as capital costs for the time period including change in FDC divided by change in reserves including revisions and production for that same time period. F&D cost is defined as capital costs for the time period including change in FDC divided by change in reserves including revisions and production for that same time period, excluding acquisitions and dispositions. Both F&D and FD&A costs take into account reserves revisions during the year on a per boe basis. The methodology used to calculate F&D costs includes disclosure required to bring the proved undeveloped and probable reserves to production. Annually, changes in forecast FDC occur as a result of Petrus' development, acquisition and disposition activities, undeveloped reserve revision and capital cost estimates. These values reflect the independent evaluator's best estimate of the cost to bring the proved and probable undeveloped reserves to production. In 2016, the P+P F&D costs including changes in FDC can generate non meaningful information because acquisitions and dispositions can have a significant impact on our ongoing reserves replacement costs.

Reserve Life Index

Reserve life index is defined as total reserves by category divided by the annualized fourth quarter production.

Reserve Replacement Ratio

The reserve replacement ratio is calculated by dividing the yearly change in reserves net of production by the actual annual production for the year.

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

ADVISORIES

Basis of Presentation

Financial data presented above has largely been derived from the Company's financial statements, prepared in accordance with GAAP which require publicly accountable enterprises to prepare their financial statements using IFRS. Accounting policies adopted by the Company are set out in the notes to the audited financial statements as at and for the twelve months ended December 31, 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, statements with respect to: the availability of cash flows from operating activities; expected 2018 debt repayment; expected year over year production; sources of financing and the requirement therefor; 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; the focus of and timing of capital expenditures; 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; 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; Petrus' future operating and financial results; capital investment programs; supply and demand for crude oil, NGL and natural gas; future royalty rates; drilling, development and completion plans and the results therefrom; and treatment under governmental regulatory regimes and tax laws. In addition, statements relating to “reserves” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

This MD&A discloses drilling locations, which are unbooked locations based on Petrus' prospective acreage and internal estimates as to the number of wells that can be drilled per section. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information.

There is no certainty that the Company will drill any unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

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*
mboe	*thousand barrel of oil equivalent*
mmboe	*million 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 ANNUAL FINANCIAL STATEMENTS

As at and for the years ended December 31, 2017 and 2016

INDEPENDENT AUDITORS' REPORT

To the Shareholders of **Petrus Resources Ltd.**

We have audited the accompanying consolidated financial statements of Petrus Resources Ltd., which comprise the consolidated balance sheets as at December 31, 2017 and 2016 and the consolidated statements of net loss and comprehensive loss, changes in shareholders' equity and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Petrus Resources Ltd. as at December 31, 2017 and 2016 and its financial performance and its cash flows for the years then ended, in accordance with International Financial Reporting Standards.

Ernst & Young LLP

Calgary, Canada
March 7, 2018

Chartered Professional Accountants

CONSOLIDATED BALANCE SHEETS

(Expressed in 000's of Canadian dollars)

As at	December 31, 2017	December 31, 2016
ASSETS		
Current		
Cash	24	280
Deposits and prepaid expenses	1,430	1,111
Accounts receivable *(note 15)*	11,588	11,527
Risk management asset *(note 10)*	2,163	22
Total current assets	**15,205**	**12,940**
Non-current		
Risk management asset *(note 10)*	572	—
Exploration and evaluation assets *(notes 5 and 6)*	43,197	64,824
Property, plant and equipment *(notes 5 and 7)*	294,471	362,203
Total assets	**353,445**	**439,967**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Bank indebtedness *(note 15)*	3,844	—
Current portion of long term debt *(note 8)*	—	42,000
Accounts payable and accrued liabilities *(note 15)*	25,601	22,066
Risk management liability *(note 10)*	—	5,696
Total current liabilities	**29,445**	**69,762**
Non-current liabilities		
Risk management liability *(note 10)*	711	1,924
Long term debt *(note 8)*	131,907	73,767
Decommissioning obligation *(note 9)*	40,654	43,243
Total liabilities	**202,717**	**188,696**
Shareholders' equity		
Share capital *(note 11)*	430,119	419,671
Contributed surplus	7,680	7,410
Deficit	(287,071)	(175,810)
Total shareholders' equity	**150,728**	**251,271**
Total liabilities and shareholders' equity	**353,445**	**439,967**

Commitments (note 20)
See accompanying notes to the 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 LOSS AND COMPREHENSIVE LOSS

(Expressed in 000's of Canadian dollars, except for share information)

	Year ended December 31, 2017	Year ended December 31, 2016
REVENUE		
Oil and natural gas revenue	**90,569**	**64,840**
Royalty expense	(13,270)	(8,947)
Net oil and natural gas revenue	**77,299**	**55,893**
Other income (expense)	—	(5)
Net gain (loss) on financial derivatives *(note 10)*	13,353	(6,529)
	90,652	**49,359**
EXPENSES		
Operating *(note 13)*	18,950	19,522
Transportation	4,880	4,457
General and administrative *(note 14)*	3,252	7,706
Share-based compensation *(note 11)*	503	527
Finance *(note 17)*	8,389	11,610
Exploration and evaluation *(note 6)*	2,783	2,426
Depletion and depreciation *(note 7)*	52,614	45,384
Loss (gain) on sale of assets *(note 5)*	1,542	(285)
Impairment *(notes 6 and 7)*	109,000	25,000
Total expenses	**201,913**	**116,347**
NET LOSS AND COMPREHENSIVE LOSS	**(111,261)**	**(66,988)**
Net loss per common share		
Basic and diluted *(note 12)*	**(2.28)**	**(1.51)**

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Expressed in 000's of Canadian dollars)

	Share Capital	Contributed Surplus	Deficit	Total
Balance, December 31, 2015	**346,106**	**6,620**	**(108,822)**	**243,904**
Net loss	—	—	(66,988)	(66,988)
Issuance of common shares *(note 11)*	75,488	—	—	75,488
Share issue costs *(note 11)*	(1,922)	—	—	(1,922)
Share-based compensation	—	789	—	789
Balance, December 31, 2016	**419,672**	**7,409**	**(175,810)**	**251,271**
Net loss	—	—	(111,261)	(111,261)
Issuance of common shares *(note 11)*	10,498	(96)	—	10,402
Share issue costs *(note 11)*	(51)	—	—	(51)
Share-based compensation	—	367	—	367
Balance, December 31, 2017	**430,119**	**7,680**	**(287,071)**	**150,728**

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Expressed in 000's of Canadian dollars)

	Year ended December 31, 2017	Year ended December 31, 2016
OPERATING ACTIVITIES		
Net loss	**(111,261)**	**(66,988)**
Adjust items not affecting cash:		
Share-based compensation *(note 11)*	503	527
Unrealized loss (gain) on financial derivatives (*note 10)*	(9,621)	21,531
Non-cash finance expenses *(note 17)*	1,395	973
Depletion and depreciation *(note 7)*	52,614	45,384
Impairment *(notes 6 and 7)*	109,000	25,000
Exploration and evaluation expense *(note 6)*	2,783	2,426
Loss (gain) on sale of assets	1,542	(285)
Decommissioning expenditures *(note 9)*	(1,952)	(756)
Funds from operations	**45,003**	**27,812**
Change in operating non-cash working capital *(note 19)*	931	14,041
Cash flows from operating activities	**45,934**	**41,853**
FINANCING ACTIVITIES		
Issue of common shares *(note 11)*	10,429	75,488
Share issue costs *(note 11)*	(51)	(1,922)
Repayment of term loan *(note 8)*	(7,000)	(48,000)
Increase in bank indebtedness	3,844	—
Transaction costs on debt	(1,541)	—
Issuance (repayment) of revolving credit facility	23,833	(71,233)
Change in financing non-cash working capital (note 19)	(847)	323
Cash flows from (used in) financing activities	**28,667**	**(45,344)**
INVESTING ACTIVITIES		
Property dispositions *(note 5)*	4,837	29,718
Property and equipment acquisitions *(note 5)*	(1,770)	—
Exploration and evaluation asset acquisitions *(note 5)*	(8,000)	—
Exploration and evaluation asset expenditures *(note 6)*	(829)	(632)
Petroleum and natural gas property expenditures *(note 7)*	(71,723)	(28,614)
Other capital expenditures	(198)	—
Change in investing non-cash working capital *(note 19)*	2,826	2,065
Cash flows from (used in) investing activities	**(74,857)**	**2,537**
Decrease in cash	(256)	(954)
Cash, beginning of year	280	1,234
Cash, end of year	**24**	**280**
Cash interest paid	6,992	10,587

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2017 and 2016

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 consolidated financial statements, which report the year ended December 31, 2017 and prior year comparative period, were approved by the Company's Board of Directors on March 7, 2018.

2. BASIS OF PRESENTATION

Statement of Compliance

(a) Statement of Compliance

These consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

(b) Measurement Basis

These consolidated financial statements were prepared on the basis of historical cost except for financial derivatives which are measured at fair value. This method is consistent with the method used in prior years. These consolidated financial statements are presented in Canadian dollars.

(c) Consolidation

These audited consolidated financial statements include the accounts of Petrus and its 100% owned subsidiaries, Petrus Resources Corp. and Petrus Resources Inc. Subsidiaries are consolidated from the date control is obtained until the date control ends. Control exists where the Company has power over the investee, exposure or rights to variable returns from the investee and the ability to use its power over the investee to affect returns. All intra-group balances and transactions are eliminated on consolidation.

(d) 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.

Depletion and reserve estimates

Petroleum and natural gas assets are depleted on a unit of production basis at a rate calculated by reference to proved and probable reserves determined in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). The calculation incorporates the estimated future cost of developing and extracting those reserves. Proved and probable reserves are estimated using independent reservoir engineering reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. Reserves estimates, although not reported as part of the Company's financial statements, can have a significant effect on net income (loss), assets and liabilities as a result of their impact on depletion and depreciation, decommissioning liabilities, deferred taxes, asset impairments and business combinations. Independent reservoir engineers perform evaluations of the Company's petroleum and natural gas reserves on an annual basis. The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable petroleum and natural gas reserves are based upon a number of variables and assumptions such as geoscientific interpretation, production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available or as economic conditions change.

Impairment indicators and cash-generating units

For purposes of impairment testing, exploration and evaluation assets and petroleum and natural gas assets are aggregated into cash-generating units ("CGUs"), based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment.

The recoverable amounts of CGU's and individual assets have been determined based on the higher of the value-in-use calculations and fair value less costs of disposal. These calculations require the use of estimates and assumptions, including the discount rate, future petroleum and natural gas prices, expected production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available and changes in economic conditions take place. Changes may impact the estimated life of the field and economical reserves recoverable and may require a material adjustment to the carrying value of exploration and evaluation assets and petroleum and natural gas assets. The Company monitors internal and external indicators of impairment relating to its tangible assets.

Technical feasibility and commercial viability of exploration and evaluation assets
The determination of technical feasibility and commercial viability, based on the presence of proved and probable reserves, results in the transfer of assets from exploration and evaluation assets to property, plant and equipment. As discussed above, the estimate of proved and probable reserves is inherently complex and requires significant judgment. Thus any material change to reserve estimates could affect the technical feasibility and commercial viability of the underlying assets.

Financial Instruments
Financial instruments are subject to valuations at the end of each reporting period. Generally the valuation is based on active and efficient markets. However, certain financial instruments may not be traded on an efficient market or the market may disappear or be subject to conditions that impede the efficiency of the market.

Decommissioning obligation
At the end of the operating life of the Company's facilities and properties and upon retirement of its petroleum and natural gas assets, decommissioning costs will be incurred by the Company. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and discount rates to determine the present value of these cash flows.

Income taxes
Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in income or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods. Changes in tax laws in the jurisdictions in which the Company operates could limit the ability of the Company to obtain tax deductions in future periods. Income taxes are subject to measurement uncertainty. Significant judgment can be involved in the recognition of deferred tax assets.

Measurement of share-based compensation
Share-based compensation recorded pursuant to share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

Business combinations
Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of exploration and evaluation assets and petroleum and natural gas assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill in the purchase price allocation.

Contingencies
By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

3. SIGNIFICANT ACCOUNTING POLICIES

(a) Revenue recognition

Revenue from the sale of petroleum and natural gas is recognized when volumes are delivered and title passes to an external party at contractual delivery points and are recorded gross of transportation charges incurred by the Company.

The costs associated with the delivery, including transportation and production-based royalty expenses, are recognized in the same period in which the related revenue is earned and recorded.

(b) Exploration & evaluation assets

Capitalization
All costs incurred after the rights to explore an area have been obtained, such as geological and geophysical costs, other direct costs of exploration (drilling, testing and evaluating the technical feasibility and commercial viability of extraction) and appraisal, and including any directly attributable general and administration costs and share-based payments, are accumulated and capitalized as exploration and evaluation ("E&E") assets.

Certain costs incurred prior to acquiring the legal rights to explore are charged directly to net loss.

Depletion & depreciation
E&E costs are not amortized prior to the conclusion of appraisal activities. At the completion of appraisal activities, if technical feasibility is demonstrated and commercial reserves are discovered, then the carrying value of the relevant E&E asset will be reclassified as a property, plant and equipment asset into the Cash Generating Units ("CGUs") to which it relates, but only after the carrying value of the relevant E&E asset has been assessed for impairment and, where appropriate, its carrying value adjusted. Technical feasibility and commercial viability are considered to be

demonstrable when proved or probable reserves are determined to exist. If it is determined that technical feasibility and commercial viability have not been achieved in relation to the exploration and evaluation assets appraised, all other associated costs are written down to the recoverable amount in net loss.

Expired land leases included as undeveloped land in E&E assets are recognized in exploration and evaluation cost in net loss upon expiry and are considered prior to expiry. Management considers upcoming land lease expiries and may recognize the costs in advance of expiry.

Impairment

Indicators of impairment of E&E assets are assessed at each reporting date which can include upcoming land lease expiries, third party land valuations and other information . When there are such indications, an impairment test is carried out and any resulting impairment loss is written off to net income (loss). The recoverable amount is the greater of fair value, less costs of disposal, or value-in-use.

(c) Property, plant and equipment

The Company's property, plant and equipment is comprised of petroleum and natural gas assets and corporate assets.

Capitalization

Petroleum and natural gas assets are measured at cost less accumulated depletion and depreciation and accumulated impairment losses, if any. Petroleum and natural gas assets consists of the purchase price and costs directly attributable to bringing the asset to the location and condition necessary for its intended use. Petroleum and natural gas assets include developing and producing interests such as land acquisitions, geological and geophysical costs, facility and production equipment, including any directly attributable general and administration costs and share-based payments and the initial estimate of the costs of dismantling and removing an asset and restoring the site on which it was located.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability are recognized as developing and producing petroleum and natural gas interests when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized petroleum and natural gas interests generally represent costs incurred in developing proved and/or probable reserves, and are accumulated on a field or geotechnical area basis. The cost of day-to-day servicing of an item of petroleum and natural gas assets is expensed in net loss as incurred. Petroleum and natural gas assets are derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising from the disposal of an asset, determined as the difference between the net disposal proceeds and the carrying amount of the asset, is recognized in net loss.

Depletion and depreciation

The costs for petroleum and natural gas properties, including related pipelines and facilities, are depleted using a unit-of-production method based on the commercial proved and probable reserves.

Petroleum and natural gas assets are not depleted until production commences. This depletion calculation includes actual production in the period and total estimated proved and probable reserves attributable to the assets being depleted, taking into account total capitalized costs plus estimated future development costs necessary to bring those reserves into production. Relative volumes of reserves and production (before royalties) are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Proved and probable reserves are estimated using independent reservoir engineering reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible.

Corporate assets are recorded at cost less accumulated depreciation. Depreciation is calculated on a declining balance method so as to write off the cost of these assets, less estimated residual values, over their estimated useful lives consistent with the treatment used for tax purposes.

Impairment

The assessment for impairment entails comparing the carrying value of the CGU with its recoverable amount: that is, the higher of fair value, less costs of disposal, and value in use. Petrus' property, plant and equipment are grouped into CGUs based on separately identifiable and largely independent cash inflows considering geological characteristics, shared infrastructure and exposure to market risks. Estimates of future cash flows used in the calculation of the recoverable amount are based on reserve evaluation reports prepared by independent reservoir engineers.

The CGU's are reviewed quarterly for indicators of impairment. Indicators are events or changes in circumstances that indicate that the carrying amount may not be recoverable. If indicators of impairment exist, the recoverable amount of the CGU is estimated. If the carrying amount of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net loss.

The recoverable amount is the higher of fair value, less costs of disposal, and the value-in-use. Fair value, less costs of disposal, is derived by estimating the discounted after-tax future net cash flows. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of the reserves and discounted using market-based rates to reflect a market participant's view of the risks associated with the assets. Value-in-use is assessed using the expected future cash flows discounted at a pre-tax rate.

Impairments of property, plant and equipment are reversed when there is significant evidence that the impairment has been reversed, but only to the extent of what the carrying amount would have been had no impairment been recognized.

(d) Business combinations

Business combinations are accounted for using the acquisition method. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their fair values at the acquisition date. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the acquisition date. The excess of the cost of the acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in net loss. Transaction costs associated with a business combination are expensed as incurred.

(e) Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning and reclamation requirements. Costs related to these abandonment activities are estimated by management in consultation with the Company's engineers based on risk-adjusted current costs which take into consideration current technology in accordance with existing legislation and industry practices.

Decommissioning obligations are measured at the present value of the best estimate of expenditures required to settle the obligations at the reporting date. When the fair value of the liability is initially measured, the estimated cost, discounted using a risk-free rate, is capitalized by increasing the carrying amount of the related petroleum and natural gas assets. The increase in the provision due to the passage of time, or accretion, is recognized as a finance expense. Increases and decreases due to revisions in the estimated future cash flows are recorded as adjustments to the carrying amount of the related petroleum and natural gas assets.

Actual costs incurred upon settlement of the liability are charged against the obligation to the extent that the obligation was previously established. The carrying amount capitalized in petroleum and natural gas assets is depleted in accordance with the Company's depletion policy. The Company reviews the obligation at each reporting date and revisions to the estimated timing of cash flows, discount rates and estimated costs will result in an increase or decrease to the obligations. Any difference between the actual costs incurred upon settlement of the obligation and recorded liability is recognized as an increase or reduction in income.

(f) Finance expenses

Finance expense may be comprised of interest expense on borrowings, acquisition related (transaction) costs, foreign exchange expenses and accretion of the discount on decommissioning obligations.

(g) Financial instruments

Non-derivative financial instruments

Non-derivative financial instruments are comprised of cash, accounts receivables, deposits, accounts payable and long term debt. Non-derivative financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured based on their classification. The Company has made the following classifications:

- Cash and deposits are classified as held for trading.
- Accounts receivable are classified as loans and receivables and are measured at amortized cost using the effective interest method.
- Accounts payable and long term debt are classified as other liabilities and are measured at amortized cost using the effective interest method.

Risk Management Contracts

The Company enters into risk management contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Petrus has not designated its risk management contracts as effective hedges, and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, all risk management contracts are classified as fair value through profit or loss and are recorded at fair value on the balance sheet with changes in fair value recorded in the statement of income (loss) and comprehensive income (loss). The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date.

(h) Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issuance of common shares are recognized as a reduction in share capital, net of any tax effects.

(i) Flow-through shares

The resources expenditure deductions for income tax purposes related to exploratory activities funded by flow-through shares are renounced to investors in accordance with tax legislation. Upon issuance of a flow-through share, a liability is recognized representing the premium paid on flow-through common shares over regular common shares. This liability is reduced as the expenditures are incurred and tax attributes are renounced.

(j) Income taxes

The Company's income tax expense is comprised of current and deferred tax. Income tax expense is recognized through income or loss except to the extent that it relates to items recognized directly in equity, in which case the related income taxes are also recognized in equity.

Current tax is the expected tax payable on taxable income for the period, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable income. Deferred tax liabilities are generally recognized for all taxable temporary differences. Deferred tax assets are generally recognized for all deductible temporary differences to the extent that it is probable that taxable income will be available against which those deductible temporary differences can be utilized. Assessing the recoverability of deferred tax assets requires management to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in the jurisdictions of Alberta and Canada. The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be recovered.

(k) Joint arrangements

A portion of the Company's exploration, development and production activities are conducted jointly with others through unincorporated joint operations. These financial statements reflect only the Company's proportionate interest of these joint operations and the proportionate share of the relevant revenue and related costs.

(l) Share-based compensation

Share-based compensation expense is determined based on the estimated fair value of shares on the date of grant. Forfeitures are estimated at the grant date and are subsequently adjusted to reflect actual forfeitures. The expense is recognized over the service period, with a corresponding increase to contributed surplus (if equity-settled) or liabilities (if cash-settled). The Company capitalizes the qualifying portion of share-based compensation expense directly attributable to the exploration and development activities of exploration and evaluation assets and petroleum and natural gas assets, with a corresponding decrease to share-based compensation expense. At the time the stock options or performance warrants are exercised, the issuance of common shares is recorded as an increase to shareholders' capital and a corresponding decrease to contributed surplus.

(m) Earnings per share

Earnings per share are presented for basic and diluted earnings. Basic per share information is computed by dividing the net income (loss) for the period attributable to equity owners of the Company by the weighted average number of common shares outstanding during the period. The weighted average number of shares for diluted earnings per share information is calculated using the treasury stock method whereby it is assumed that proceeds obtained upon exercise of performance warrants and stock options would be used to purchase common shares at the average market price during the period. The treasury stock method also assumes that the deemed proceeds related to unrecognized share-based payments expense are used to repurchase shares at the average market price during the period. Under the treasury stock method, stock options and share warrants have a dilutive effect only when the average market price of the common shares during the period exceeds the exercise price of the options or warrants (they are "in-the-money"). Exercise of in-the-money stock options and share warrants is assumed at the beginning of the year or date of issuance, if later. Should the Company have a loss for the period, stock options and share warrants would be anti-dilutive and therefore will have no effect on the determination of loss per share.

(n) Leases

The determination of whether an arrangement is, or contains a lease is based on the substance of the arrangement at the inception date, whether fulfillment of the arrangement is dependent on the use of a specific asset or the arrangement conveys a right to use an asset. Leases which transfer substantially all the risks and benefits of ownership to the Company are classified as finance leases. The leased asset is recognized at the lower of the fair value of the leased property or the present value of the minimum lease payments. Finance lease assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Other leases are classified as operating leases and payments are amortized on a straight-line basis over the lease term.

(o) New standards and interpretations

IFRS 9 Financial Instruments

In July 2014, the IASB completed the final elements of IFRS 9 "Financial Instruments." The Standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement." IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The Standard will come into effect for annual periods beginning on or after January 1, 2018 with earlier adoption permitted. IFRS 9 will be applied by Petrus on January 1, 2018, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded in OCI rather than the statement of operations, unless this creates an accounting mismatch.

In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss impairment model required by IAS 39. The new model will result in more timely recognition of expected credit losses. IFRS 9 also contains a new model to be applied for hedge accounting, aligning hedge accounting more closely with risk management. The Company does not currently apply hedge accounting to its risk management contracts and does not currently intend to apply hedge accounting to any of its existing risk management contracts on adoption of IFRS 9.

Management has concluded that the adoption of IFRS 9 will not have a material impact on the Company's consolidated financial statements.

IFRS 15 Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The standard is required to be adopted for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. This standards applies to new contracts dated on or after the effective date and to existing contracts not yet completed as of the effective date. IFRS 15 will be applied by Petrus, using the modified retrospective method, on January 1, 2018. Based on its analysis of customer contracts, management has concluded that there will not be an adjustment to the timing of revenue recognition under the new standard. The adoption of IFRS 15 may result in presentation changes in revenue which are not expected to affect net income (loss).

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. Early application is permitted, but not before an entity applies IFRS 15. 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. In 2018, Petrus plans to assess the potential effect of IFRS 16 on its consolidated financial statements.

4. DETERMINATION OF FAIR VALUES

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

Petroleum and natural gas properties and equipment and exploration and evaluation assets
The fair value of petroleum and natural gas properties and equipment recognized in a business combination and for impairment testing, is based on market values. The market value of petroleum and natural gas properties and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in petroleum and natural gas properties and equipment) and intangible exploration and evaluation assets is estimated with reference to the discounted cash flow expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. The fair value less costs of disposal value used to determine the recoverable amount of the impaired petroleum and natural gas properties are classified as Level 3 fair value measurements. Refer to *"Financial Instruments"* section below for fair value hierarchy classifications.

Derivatives
The fair value of commodity price risk management contracts is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options is based on option models that use published information with respect to volatility, prices, interest rates and counter-party credit risks.

Share-based payments
The fair value of employee share-based payments is measured using a Black-Scholes option-pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility in share price (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behavior), expected dividend yield, risk-free interest rate (based on government bonds) and estimated forfeiture rate at each reporting date.

Financial Instruments
The Company's fair value measurements require disclosure about how the fair value was determined based on significant levels of inputs described in the following hierarchy:

- Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

- Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

- Level 3 - Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level. The Company's cash and deposits are considered Level 1 and risk management contracts are considered Level 2.

5. ACQUISITIONS AND DISPOSITIONS

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 this disposition during the year ended December 31, 2017.

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

Fair value of 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:

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.

Property disposition - Peace River

On July 8, 2016 Petrus closed the disposition of its oil and gas interests in the Peace River area of Alberta for total consideration of $29.4 million after post-closing adjustments, comprised of $28.4 million in cash and 1.0 million shares of the purchaser. The Company recorded a gain of $0.2 million related to the disposition during the year ended December 31, 2016.

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

Net assets disposed $000s	
Exploration and evaluation assets	7,000
Petroleum and natural gas properties and equipment	37,496
Decommissioning obligations	(15,277)
Total net assets disposed	**29,219**

Asset exchange agreement

On September 30, 2016, Petrus closed a property swap transaction disposing of non-core assets in its Foothills area for assets in its Ferrier core area for the swap assets. The Company recorded a gain of $0.4 million on the asset exchange during the year ended December 31, 2016.

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

Net assets disposed $000s	
Exploration and evaluation assets	3,509
Petroleum and natural gas properties and equipment	10,847
Decommissioning obligations	(2,773)
Total net assets disposed	**11,583**

Fair value of net assets acquired $000s	
Petroleum and natural gas properties and equipment	12,388
Decommissioning obligations	(805)
Total net assets acquired	**11,583**

During the third quarter of 2016, Petrus closed other dispositions of non-core exploration and evaluation assets and petroleum and natural gas properties and equipment for total cash consideration of $0.5 million. No gain or loss was realized on the transaction.

6. EXPLORATION AND EVALUATION ASSETS

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

$000s	
Balance, December 31, 2015	**88,178**
Additions	3
Exploration and evaluation expense	(2,426)
Capitalized G&A	629
Capitalized share-based compensation	51
Impairment loss on assets held for sale	(4,000)
Property dispositions	(10,767)
Transfers to property, plant and equipment	(6,845)
Balance, December 31, 2016	**64,824**
Additions	309
Property acquisition *(note 5)*	8,000
Exploration and evaluation expense	(2,783)
Capitalized G&A	520
Capitalized share-based compensation *(note 11)*	75
Property disposition *(note 5)*	(1,438)
Transfers to property, plant and equipment *(note 7)*	(7,036)
Impairment loss	(19,274)
Balance, December 31, 2017	**43,197**

For the year ended December 31, 2017, the Company incurred exploration and evaluation expense of $2.8 million, which relates to expired and near expiry undeveloped, non-core land (2016 – $2.4 million).

During the year ended December 31, 2017, the Company capitalized $0.5 million of general and administrative expenses ("G&A") (2016 – $0.6 million) and $0.1 million of non-cash share-based compensation directly attributable to exploration activities (2016 – $0.1 million).

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.

7. 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, 2015	**718,314**	**(285,422)**	**432,892**
Additions	26,861	—	26,861
Property acquisitions	12,387	—	12,387
Property (dispositions)	(50,172)	—	(50,172)
Capitalized G&A	1,844	—	1,844
Capitalized share-based compensation	211	—	211
Transfers from exploration and evaluation assets	6,845	—	6,845
Depletion & depreciation	—	(45,384)	(45,384)
Decrease in decommissioning provision	(2,281)	—	(2,281)
Impairment loss	—	(21,000)	(21,000)
Balance, December 31, 2016	**714,009**	**(351,806)**	**362,203**
Additions	70,361	—	70,361
Property acquisitions *(note 5)*	1,729	—	1,729
Property dispositions *(note 5)*	(15,078)	9,320	(5,758)
Capitalized G&A	1,560	—	1,560
Capitalized share-based compensation *(note 11)*	226	—	226
Transfers from exploration and evaluation assets *(note 6)*	7,036	—	7,036
Depletion & depreciation	—	(52,614)	(52,614)
Increase in decommissioning provision *(note 9)*	(545)	—	(545)
Impairment loss	—	(89,727)	(89,727)
Balance, December 31, 2017	**779,298**	**(484,827)**	**294,471**

At December 31, 2017, estimated future development costs of $283.0 million (December 31, 2016 – $269.1 million) associated with the development of the Company's proved plus probable undeveloped reserves were included with the costs subject to depletion. During the year ended December 31, 2017, the Company capitalized $1.6 million of general and administrative expenses ("G&A") (2016 – $1.8 million) and non-cash share-based compensation of $0.23 million, directly attributable to development activities (2016 – $0.2 million).

During the year ended December 31, 2017, the Company acquired developed oil and natural gas assets of $1.7 million (note 5). The Company also sold developed oil and natural gas assets in the Foothills area for total cash consideration of $4.9 million (note 5).

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.

For the year ended December 31, 2017, the Company performed an impairment test for the Ferrier CGU, and no impairment charge was recorded as the recoverable amount of the Ferrier CGU was considerably higher than its carrying value. The recoverable amount of the Ferrier CGU was estimated at fair value less costs of disposal.

During the third quarter of 2016, the Company sold its oil and natural gas interests in the Peace River area of Alberta to a private company for total consideration of $30.0 million, subject to customary closing adjustments (see note 3 - Property Disposition - Peace River). On July 8, 2016 Petrus closed the disposition of its oil and gas interests in the Peace River area of Alberta for total consideration of $29.5 million after post-closing adjustments, comprised of $28.5 million in cash and 1.0 million shares of the purchaser. The Company sold the shares during the fourth quarter of 2016 for $1.07 million. $1.0 million was recorded as cash proceeds for the disposition and the Company recognized a gain of $0.1 million related to the disposition of shares during the year ended December 31, 2016. On June 30, 2016, these assets were recorded at the lesser of fair value less costs of disposal and their carrying amount, resulting in an impairment loss of $25.0 million ($21.0 million recorded to Property, Plant and Equipment and $4.0 million recorded to Exploration & Evaluation Assets). The impairment was recorded as an impairment loss on the Consolidated Statements of Net Loss.

8. DEBT

At December 31, 2017 Petrus had two debt instruments outstanding. The first is a reserve-based, revolving credit facility with a syndicate of lenders. The total facility is comprised of an operating facility and a syndicated term-out facility (altogether the “Revolving Credit Facility” or “RCF”). The second is a subordinated term loan (the “Term Loan”).

(a) Revolving Credit Facility

At December 31, 2017 the Company’s RCF was comprised of a $20 million (December 31, 2016 - $20 million) operating facility and a $100 million (December 31, 2016 - $86 million) syndicated term-out facility. Lender consent is required for total borrowings against the RCF exceeding $105 million. The term-out facility has a revolving period that ends May 31, 2018 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.

At December 31, 2017, the Company had a $0.3 million letter of credit outstanding against the RCF (December 31, 2016 – $0.3 million) and had drawn $97.6 million against the RCF (December 31, 2016 – $73.8 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 lender consent. A decrease in the borrowing base could result in a reduction to the available credit under the RCF.

(b) Term Loan

At December 31, 2017 the Company had a $35 million (December 31, 2016 – $42 million) Term Loan outstanding (excluding $0.7 million of unamortized deferred financing costs), which is due October 8, 2019. 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.

Covenants

The following definitions are used in the covenant calculations for both debt instruments:

Debt to EBITDA Ratio
Debt is defined as Petrus’ total debt outstanding of the borrower and EBITDA means earnings before interest, taxes, depreciation and amortization.

Working Capital
Working Capital means Current Assets to Current Liabilities whereby Current Assets means on any date of determination, the current assets of Petrus that would, in accordance with IFRS, be classified as of that date as current assets plus any undrawn availability under the RCF, less any non-cash amount required to be included in current assets as the result of the application of IFRS including non-cash commodity and interest rate hedges assets and liabilities and whereby Current Liabilities means, on any date of determination, the liabilities of Petrus that would, in accordance with IFRS, be classified as of that date as current liabilities, excluding (a) non-cash obligations under IFRS including non-cash commodity and interest rate hedges assets and liabilities, and (b) the current portion of long-term debt.

Working Capital Ratio *means the ratio of Current Assets to Current Liabilities as defined above.*

Proved Asset and PDP Asset Coverage Ratio
Means the ratio of (a) Total Adjusted Present Value or (b) PDP Present Value depending on the reserve category, to Total Debt
Whereby Total Adjusted or PDP reserve value means the present value (discounted at 10%) of future net revenues attributable to the respective reserve category based on the reserve report most recently delivered to the lender.

The RCF carries the following covenants:

a. The Company is unable to borrow amounts greater than the RCF limit;
b. Proved Asset and PDP Asset Coverage Ratio (shown below) must be reported at each borrowing base redetermination date, using the most current reserve report and the Net Secured Debt at the date of the annual borrowing base redetermination which will take place on or before May 31, 2018.

The key financial covenants as at December 31, 2017 are summarized in the following table.

Covenant Description	Required Ratio	As at December 31, 2017
Working Capital Ratio	Over 1.00	1.19
Proved Asset Coverage Ratio (1)	Over 1.25	2.35
PDP Asset Coverage Ratio (1)	Over 1.00	1.59
Debt to EBITDA Ratio	Under 3.50	2.43

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

At December 31, 2017 the Company is in compliance with all debt covenants.

9. 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 2.22 percent and an inflation rate of 2.00 percent (December 31, 2016 – 2.24 percent and 2.00 percent, respectively). Changes in estimates in 2016 and 2017 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 $40.7 million as at December 31, 2017 ($43.2 million at December 31, 2016). The undiscounted, uninflated total future liability at December 31, 2017 is $43.1 million ($46.0 million at December 31, 2016). 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, 2015	**64,357**
Property acquisitions	805
Property dispositions	(19,854)
Liabilities incurred	1,555
Liabilities settled	(756)
Change in estimates	(3,837)
Accretion expense	973
Balance, December 31, 2016	**43,243**
Property acquisitions *(note 5)*	151
Property disposition *(note 5)*	(1,232)
Liabilities incurred	2,530
Liabilities settled	(1,952)
Change in estimates	(3,075)
Accretion expense	989
Balance, December 31, 2017	**40,654**

10. 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 December 31, 2017:

Contract Period	Type	Total Daily Volume (GJ)	Average Price (CDN$/GJ)
Natural Gas Swaps			
Jan. 1, 2018 to Mar. 31, 2018	Fixed price	27,500	$2.85
Jan. 1, 2018 to Oct. 31, 2018	Fixed price	2,000	$2.52
Jan. 1, 2018 to Dec. 31, 2018	Fixed price	4,000	$2.03
Apr. 1, 2018 to Oct. 31, 2018	Fixed price	21,000	$2.29
Nov. 1, 2018 to Mar. 31, 2019	Fixed price	19,000	$2.52
Apr. 1, 2019 to Oct. 31, 2019	Fixed price	10,000	$1.85
Natural Gas Collars			
Jan. 1, 2018 to Mar. 31, 2018	Costless collar	2,000	$2.80-3.35

Contract Period	Type	Total Daily Volume (Bbl)	Average Price (CDN$/Bbl)
Crude Oil Swaps			
Jan. 1, 2018 to Mar. 31, 2018	Fixed price	500	$64.44
Jan. 1, 2018 to Dec. 31, 2018	Fixed price	1,000	$63.76
Apr. 1, 2018 to Jun. 30, 2018	Fixed price	600	$68.44
Apr. 1, 2018 to Dec. 31, 2018	Fixed price	50	$70.75
Jul. 1, 2018 to Sep. 30, 2018	Fixed price	600	$69.90
Oct. 1, 2018 to Dec. 31, 2018	Fixed price	200	$67.25
Oct. 1, 2018 to Jun. 30, 2019	Fixed price	300	$61.60
Jan. 1, 2019 to Mar. 31, 2019	Fixed price	1,000	$62.27
Apr. 1, 2019 to Jun. 30, 2019	Fixed price	800	$63.86
Jul. 1, 2019 to Sep. 30, 2019	Fixed price	300	$64.05
Jul. 1, 2019 to Dec. 31, 2019	Fixed price	500	$63.23
Oct. 1, 2019 to Dec. 31, 2019	Fixed price	300	$63.85
Crude Oil Collars			
Jan. 1, 2018 to Jun. 30, 2018	Costless collar	100	$65.00-75.55
Jan. 1, 2018 to Mar. 31, 2018	Costless collar	300	$55.00-64.02
Jan. 1, 2018 to Mar. 31, 2018	Costless collar	300	$60.00-73.60
Jan. 1, 2018 to Jun. 30, 2018	Costless collar	100	$60.00-65.25
Apr. 1, 2018 to Jun. 30, 2018	Costless collar	100	$60.00-67.25
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 December 31, 2017	Asset	Liability
Current commodity derivatives	2,163	—
Non-current commodity derivatives	572	711
	2,735	**711**

$000s At December 31, 2016	Asset	Liability
Current commodity derivatives	22	5,696
Non-current commodity derivatives	—	1,924
	22	**7,620**

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

$000s	Year ended Dec. 31, 2017	Year ended Dec. 31, 2016
Realized gain on financial derivatives	3,732	15,002
Unrealized gain (loss) on financial derivatives	9,621	(21,531)
Net gain (loss) on financial derivatives	**13,353**	**(6,529)**

Subsequent to December 31, 2017, the Company entered into the following financial derivative contracts:

Contract Period	Type	Daily Volume (Bbl)	Price (CAD$/Bbl)
Crude Oil			
Jul. 1, 2018 to Sep. 30, 2018	Fixed price	100	$76.90
Oct. 1, 2018 to Dec. 31, 2018	Fixed price	200	$72.75
Oct. 1, 2018 to Dec. 31, 2018	Fixed price	100	$75.30
Jul. 1, 2019 to Sep. 30, 2019	Fixed price	100	$69.25
Jul. 1, 2019 to Sep. 30, 2019	Fixed price	100	$70.70
Jan. 1, 2020 to Mar. 31, 2020	Fixed price	200	$67.55
Jan. 1, 2020 to Mar. 31, 2020	Fixed price	200	$66.65

11. 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, 2015	**35,148,150**	**346,106**
Common shares issued under equity financing	4,054,250	30,000
Common shares issued under the arrangement agreement	6,146,792	45,487
Share issue costs	—	(1,922)
Balance, December 31, 2016	**45,349,192**	**419,672**
Common shares issued under equity financing (a)	4,078,708	10,319
Common shares issued on exercise of stock options	63,940	179
Share issue costs (b)	—	(51)
Balance, December 31, 2017	**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.
(b) During 2017 the Company incurred legal and regulatory costs attributed to the private placement of $0.05 million which were recorded as share issue costs.

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 December 31, 2017, 2,914,930 (December 31, 2016 – 1,976,580) total stock options were outstanding. The summary of stock option activity is presented below:

	Number of stock options	Weighted average exercise price
Balance, December 31, 2015	**1,453,750**	**$9.28**
Granted	791,580	$1.98
Forfeited or expired	(268,750)	$7.00
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**
Exercisable, December 31, 2017	**541,170**	**$12.16**

The following table summarizes information about stock options outstanding as at December 31, 2017:

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)**
$1.98 - $2.33	2,357,430	$2.20	1.53	—	—	—
$9.00 - $16.00	557,500	$12.70	1.57	541,170	$12.16	1.47
	2,914,930	**$4.21**	**1.57**	**541,170**	**$12.16**	**1.47**

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 2017 of $0.64 was estimated on the date of grant using the Black-Scholes pricing model with the following weighted average assumptions:

	2017	**2016**
Risk free interest rate	0.80% - 0.95%	0.67% - 0.73%
Expected life (years)	1.08 - 3.08	1.08 - 3.08
Estimated volatility of underlying common shares (%)	61%	55%
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 participants to receive 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 December 31, 2017, 130,038 (December 31, 2016 – nil) Deferred Share Units were issued and outstanding and are summarized in the table below.

	Number of units outstanding	Weighted average exercise price
Balance, December 31, 2016	—	—
Granted	130,038	$2.63
Balance, December 31, 2017	**130,038**	**$2.63**
Exercisable, December 31, 2017	—	—

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**

Performance Warrants

The Company has issued performance warrants to employees, consultants and directors of the Company ("Performance Warrants"). Performance Warrants were granted and vest based on three criteria, time (one third vest per year), market (one third vest as certain share price hurdles are achieved) and employment or service. The Performance Warrants expire five years from the date of issuance. Upon exercise of the Performance Warrants the Company may settle the obligation by issuing common shares of the Company. The aggregate number of shares issuable upon the exercise of all Performance Warrants granted shall not exceed 20% of the 8.0 million issued and outstanding common shares as at April 30, 2012.

At December 31, 2017, Nil (December 31, 2016 – 429,667) Performance Warrants were issued and outstanding and are summarized in the table below.

	Number of warrants outstanding	Weighted Average Exercise Price ($)
Balance, December 31, 2015	**1,568,568**	**$8.07**
Forfeited or expired	(1,138,901)	$8.02
Balance, December 31, 2016	**429,667**	**$8.14**
Forfeited or expired	(429,667)	$9.00
Balance, December 31, 2017	—	—
Exercisable, December 31, 2017	—	—

No Performance Warrants were issued during the years ended December 31, 2017 or 2016**.**

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

$000s	Year ended December 31, 2017	Year ended December 31, 2016
Expensed related to stock options	259	527
Expensed related to deferred share units	244	—
Capitalized to exploration and evaluation assets	75	51
Capitalized to property, plant and equipment	226	212
Total share-based compensation	**804**	**789**

12. LOSS PER SHARE

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

		2017		2016
Net loss for the period ($000s)		**(111,261)**		**(66,988)**
Weighted average number of common shares – basic (000s)		48,825		44,429
Weighted average number of common shares – diluted (000s)		48,825		44,429
Net loss per common share – basic	**$**	**(2.28)**	**$**	**(1.51)**
Net loss per common share – diluted	**$**	**(2.28)**	**$**	**(1.51)**

For the year ended December 31, 2017, there were nil warrants (December 31, 2016 – 429,667), 2,914,930 stock options (December 31, 2016 – 1,976,580) that were excluded from the calculation as their impact is anti-dilutive.

13. OPERATING EXPENSES

The Company's gross operating expenses for the year ended December 31, 2017 were $20.0 million (December 31, 2016 – $22.3 million), which includes $6.3 million of processing, gathering and compression charges (December 31, 2016 – $5.2 million).

The Company generated processing income recoveries of $1.1 million for the year ended December 31, 2017 (December 31, 2016 – $2.7 million), which reduced the Company's gross operating expenses to $19.0 million for the year ended December 31, 2017 (December 31, 2016 – $19.5 million).

14. GENERAL AND ADMINISTRATIVE EXPENSES

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

$000s	**2017**	**2016**
Personnel, consultants and directors	4,803	6,593
Office costs	2,929	2,306
Regulatory and public company expenses	1,055	1,265
Capitalized general and administrative and overhead recoveries	(5,535)	(2,458)
General and administrative expense	**3,252**	**7,706**

15. 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 $11.6 million of accounts receivable outstanding at December 31, 2017 (December 31, 2016 – $11.5 million), $8.7 million is owed from 4 parties (December 31, 2016 – $10.5 million from 10 parties), and the balances were received subsequent to the year end. The Company considers accounts receivable outstanding past 120 days to be 'past due'. At December 31, 2017, the Company had an allowance for doubtful accounts of $0.1 million (nil at December 31, 2016). As at December 31, 2017, 98% of Petrus' accounts receivable were aged less than 120 days and 2% 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 December 31, 2017, the Company had a $105 million RCF (lender consent is required for total borrowings against the RCF exceeding $105 million (see note 8), of which $7.1 million was undrawn (December 31, 2016 – $31.9 million was undrawn). 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 cash flows from operating activities and available credit capacity from its RCF. In November 2017, Petrus completed the semi-annual review of its revolving credit facility ("RCF"). The RCF syndicate of lenders increased the borrowing base from $120 million to $130 million. In addition, the Company's total borrowing limit was increased from $141 million to $155 million. Petrus' Term Loan has $35 million outstanding therefore lender consent, from both the RCF syndicate and Petrus' Term Loan lender, is required for total borrowings against the RCF that exceed $120 million. The next scheduled borrowing base redetermination date for the RCF is on or before May 31, 2018.

The following are the contractual maturities of financial liabilities as at December 31, 2017:

$000s	**Total**	**< 1 year**	**1-5 years**
Accounts payable	25,601	25,601	—
Risk management liability	711	—	711
Bank indebtedness and long term debt	135,751	3,844	131,907
Total	**162,063**	**29,445**	**132,618**

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 year ended December 31, 2017 would have increased net loss by approximately $1.2 million, which relates to interest expense on the average outstanding RCF and Term Loan during the period assuming that all other variables remain constant (December 31, 2016 – $1.8 million). A 1% decrease in the Canadian prime interest rate during the period would result in an opposite impact on net 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.

As at December 31, 2017, it is estimated that a $0.25/GJ decrease in the price of natural gas would have decreased net loss by $3.6 million (December 31, 2016 – $2.6 million). As at December 31, 2017, it is estimated that a $5.00/CDN WTI/bbl decrease in the price of oil would have decreased net loss by $5.4 million (December 31, 2016 – $1.4 million and $1.2 million respectively). An opposite change in commodity prices would result in an opposite impact on net loss.

16. 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.

17. FINANCE EXPENSES

The components of finance expenses are as follows:

$000s	**2017**	**2016**
Cash:		
Interest	6,992	10,587
Foreign exchange	2	50
Total cash finance expenses	6,994	10,637
Non-cash:		
Amortization of deferred financing costs	406	—
Accretion on decommissioning obligations *(note 9)*	989	973
Total non-cash finance expenses	1,395	973
Total finance expenses	**8,389**	**11,610**

18. DEFERRED INCOME TAXES

$000s	2017	2016
Income (loss) before taxes	(111,261)	(66,988)
Combined federal and provincial tax rate	27.0%	27.0%
Computed "expected" tax expense (recovery)	(30,323)	(18,086)
Increase/(decrease) in taxes resulting from:		
Permanent items	5	5
Share based payments	136	142
Share issuance costs	(14)	(473)
True up and other	(1,264)	373
Unrecognized deferred income tax asset	31,460	18,039
Deferred tax expense (recovery)	—	—
Effective tax rate	—	—

The components of the Company's deferred tax position at December 31, 2017 and 2016 are as follows:

$000s	2017	2016
Exploration and evaluation assets and property, plant and equipment	(1,847)	(24,439)
Asset retirement obligations	—	11,676
Share issuance costs	546	911
Non capital loss carry-forwards	1,847	9,801
Unrealized hedging gain (loss)	(546)	2,051
Deferred tax liability	—	—

As at December 31, 2017, Petrus had unrecognized deductible temporary differences of decommissioning liabilities of approximately $40.7 million and non-capital losses of approximately $154.0 million. The Company had non-capital losses of approximately $160.9 million (2016 – $114.5 million) which may be applied against future income for Canadian tax purposes. These non-capital losses expire in 2026 and onwards.

19. SUPPLEMENTAL CASH FLOW INFORMATION

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

$000s	2017	2016
Source (use) in non-cash working capital:		
Deposits and prepaid expenses	(319)	(25)
Accounts receivable	(61)	6,227
Accounts payable and accrued liabilities (excluding deferred share units liability)	3,291	10,227
	2,911	**16,429**
Operating activities	931	14,041
Financing activities	(847)	323
Investing activities	2,826	2,065

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, 2016	—	73,767	42,000	115,767
Cash flows	3,844	23,833	(7,000)	20,677
Non-cash changes	—	—	(693)	(693)
Balance, December 31, 2017	3,844	97,600	34,307	135,751

20. COMMITMENTS

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

$000s	Total	< 1 year	1-5 years	> 5 years
Corporate office lease	1,491	716	775	—
Firm service transportation	20,074	1,042	11,228	7,804
Total commitments	**21,565**	**1,758**	**12,003**	**7,804**

21. RELATED PARTY TRANSACTIONS

The Company considers its directors and officers to be key management personnel. The following table outlines transactions with key management personnel:

$000s	2017	2016
Salaries, consulting fees, benefits and director fees, gross	1,690	1,728
Termination payments and benefits	—	663
Share based compensation, gross	482	15
	2,172	**2,406**

On February 28, 2017, the Chairman of the Company acquired 1,585,000 common shares ("Common Shares") of Petrus 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.

CORPORATE INFORMATION

OFFICERS

Neil Korchinski, P. Eng.
President and
Chief Executive Officer

Cheree Stephenson, CA, CPA
Vice President, Finance and
Chief Financial Officer

Marcus Schlegel, P. Eng.
Vice President, Engineering

Brett Booth, BA
Vice President, Land

Ross Keilly, BSc, MSc
Vice President, Exploration

DIRECTORS

Don T. Gray
Chairman
Scottsdale, Arizona

Neil Korchinski
Calgary, Alberta

Patrick Arnell
Calgary, Alberta

Donald Cormack
Calgary, Alberta

Brian Minnehan
Irving, Texas

Jeff Zlotky
Irving, Texas

Stephen White
Calgary, Alberta

SOLICITOR

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

AUDITOR
Ernst & Young LLP
Chartered Professional Accountants
Calgary, Alberta

INDEPENDENT RESERVE EVALUATORS
Sproule and Associates
Calgary, Alberta

BANKERS
TD Securities
Calgary, Alberta

Macquarie Bank Limited
Houston, Texas

TRANSFER AGENT
Computershare Trust Company
Calgary, Alberta

HEAD OFFICE
2400, 240 – 4th Avenue S.W.
Calgary, Alberta T2P 5H4
Phone: 403-984-9014
Fax: 403-984-2717

WEBSITE
www.petrusresources.com