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THIRD QUARTER REPORT

For the three and nine months ended September 30, 2015

Petrus Resources Ltd. ("Petrus" or the "Company") is pleased to report operating and financial results for the third quarter of 2015.

- Production in the third quarter averaged 8,668 boe per day (38% oil and liquids), an increase of 76% compared to 4,928 boe per day (41% oil and liquids) in the third quarter of 2014. Since mid-January, a portion of the Company's sales volume (affecting three of the four operating areas) has been restricted due to transportation curtailments on TransCanada Pipelines Limited ("TCPL") infrastructure. During the third quarter, approximately 1,300 boe per day was curtailed by these third party transportation restrictions.

- Petrus generated $10.8 million in funds from operations during the third quarter, compared to $9.9 million in the third quarter of 2014. Commodity prices have declined significantly from the prior year. The average benchmark natural gas price in Canada (AECO) decreased by 31% year over year (averaging $2.91 per mcf in the third quarter of 2015, compared to $4.19 per mcf in the same period a year ago). The average price of Edmonton Light Sweet crude oil decreased 44% over the same period (from $97.71 per bbl to $54.95 per bbl).

- Operating costs in the third quarter of 2015 were $7.87 per boe, down 19% from $9.69 per boe in the third quarter of 2014. The decrease is partly a result of the Company's investment in new facilities. Petrus is focused on further reducing operating expenses and increasing processing revenue. The Company is constructing a gas plant in the Ferrier area; the 25 mmcf per day plant will be connected directly to a TCPL sales pipeline and will be capable of NGL refrigeration and liquids recovery in order to reduce reliance on third parties for processing. The plant is expected to be on stream by late November 2015.

- As a result of the significant decline in commodity prices Petrus reorganized corporate and field personnel responsibilities which led to a reduction in the number of employees and contractors. All other compensation was also reduced which came into effect in the fourth quarter. The changes will result in G&A and operating cost savings of approximately $0.35 per boe and $0.25 per boe, respectively. Corporate G&A expense in the third quarter, before any changes took effect, was $2.10 per boe, compared to $3.19 in the same period a year earlier.

- Over the three month period ended September 30, 2015, Petrus invested $9.0 million in exploration and development activity. The investments were funded by cash flow. To date in 2015, the Company has invested $6.3 million in a gas processing facility in the Ferrier area. Petrus expects to invest $4.5 million in the fourth quarter with excess cash flow used to reduce debt.

- The Company ended the third quarter with 140.6 million common shares outstanding and had drawn $143.0 million against its $200.0 million credit facility. At September 30, 2015 Petrus had net debt of $226.8 million and a $2.4 million outstanding letter of credit (required until the facility construction is complete in the Ferrier area).

- At the end of the third quarter Petrus had 248,035 net acres of undeveloped land, a two-fold increase over the undeveloped land position a year earlier.

- Subsequent to September 30, 2015 Petrus was subject to a semi-annual review of its revolving credit facility. The $180 million revolving credit facility was reduced to $160 million as a result of the reduced outlook in forward commodity pricing. The $20 million development tranche was voluntarily terminated by Petrus to reduce associated standby fees.

September 30, 2015

SELECTED FINANCIAL INFORMATION

(000s) except per boe amounts	Three months ended Sep. 30, 2015	Three months ended Sep. 30, 2014	Three months ended June 30, 2015	Three months ended Mar. 31, 2015	Three months ended Dec. 31, 2014
OPERATIONS					
Average Production					
Natural gas (mcf/d)	32,505	17,557	33,103	31,525	34,626
Oil (bbl/d)	2,616	1,799	2,811	3,559	2,998
NGLs (bbl/d)	634	203	560	519	1,053
Total (boe/d)	**8,668**	**4,928**	**8,890**	**9,333**	**9,822**
Total (boe)	**797,439**	**453,359**	**808,947**	**839,927**	**903,620**
Natural gas sales weighting	***62%***	59%	***62%***	***56%***	*59%*
Realized Sales Prices					
Natural gas ($/mcf)	2.92	4.23	2.90	3.12	3.97
Oil ($/bbl)	50.91	95.51	64.76	47.38	67.47
NGLs ($/bbl)	16.14	51.08	24.99	29.77	47.52
Total ($/boe)	27.48	52.04	32.85	30.27	39.37
Hedging gain (loss) ($/boe)	4.72	(3.00)	3.58	5.81	3.73
Operating Netback ($/boe)					
Effective price	32.20	49.04	36.43	36.08	43.10
Royalty income	0.10	0.28	0.08	0.09	0.47
Royalty expense	(2.89)	(8.90)	(3.73)	(4.55)	(4.38)
Operating expense	(7.87)	(9.69)	(9.14)	(7.78)	(6.43)
Transportation expense	(1.43)	(2.87)	(1.93)	(1.86)	(1.25)
Operating netback [(1)] ($/boe)	20.11	27.86	**21.71**	**21.98**	31.51
G & A expense [(2)]	(2.10)	(3.19)	(2.28)	(1.98)	(2.34)
Net interest expense [(3)]	(4.41)	(2.88)	(3.91)	(2.72)	(1.93)
Corporate netback [(1)] ($/boe)	13.60	21.79	**15.52**	**17.28**	27.24
FINANCIAL ($000s except per share)					
Oil and natural gas revenue	21,991	23,592	26,576	25,495	35,998
Funds from operations [(1)]	10,838	9,878	12,549	14,535	24,627
Funds from operations per share [(1)]	0.08	0.09	0.09	0.10	0.18
Net income (loss)	(19,055)	7,530	(7,239)	(6,312)	(63,308)
Net income (loss) per share	(0.14)	0.07	(0.05)	(0.05)	(0.45)
Capital expenditures	9,041	28,964	13,288	25,383	53,049
Net acquisitions (dispositions)	—	113,605	(125)	1,063	195,028
Common shares outstanding	140,593	140,458	140,593	140,593	140,593
Weighted average shares	140,593	108,212	140,593	140,593	140,571
As at quarter end ($000s)					
Net debt [(1)(4)]	(226,809)	21,014	(228,562)	(227,607)	(215,049)
Bank debt outstanding	143,000	90,000	142,000	115,000	190,000
Bank debt available [(5)]	34,600	50,000	35,600	85,000	100,000
Shareholders' equity	280,118	374,070	299,061	305,912	311,760
Total assets	595,890	549,248	627,808	641,547	647,304

(1) Non-GAAP measures are defined on pages 5 and 6 of the September 30, 2015 MD&A.

(2) G&A expense is presented net of capitalized general & administrative costs. Please refer to the G&A section on page 10 in the September 30, 2015 MD&A.

(3) Interest expense is presented net of other income and non-cash deferred finance expense.

(4) Net debt includes working capital (deficiency).

(5) $200 million credit facility less: $20 million non-borrowing base facility, $143 million drawn and $2.4 million letter of credit.

OPERATIONS UPDATE

Average production for the quarter ended Sept. 30, 2015	Ferrier	Foothills	Peace River	Central Alberta	Total
Average Production					
Natural gas (mcf/d)	11,004	7,653	2,904	10,944	**32,505**
Oil (bbl/d)	457	567	766	824	**2,614**
NGLs (bbl/d)	315	27	21	268	**631**
Total (boe/d)	**2,608**	**1,872**	**1,272**	**2,916**	**8,668**
Natural gas sales weighting	***70%***	***68%***	***38%***	***63%***	***62%***

Petrus invested $8.1 million in the Ferrier area in the third quarter of 2015 including completion operations for two wells which were drilled earlier in 2015. The two wells were brought on production during the quarter. The remainder of the capital invested during the third quarter was directed toward construction of a gas processing facility. The facility is expected to come on stream late November 2015 and is designed to mitigate capacity constraints and reduce exposure to operations outside of the Company's control.

Rolling transportation curtailments since January on major TCPL infrastructure forced many producers to reduce sales volumes. Petrus was required to shut in some production in three of its operating areas during the third quarter and the Company estimates that approximately 1,300 boe per day was curtailed by these third party transportation restrictions during the third quarter.

The most significant production curtailments affect the Ferrier area where a major outage at TCPL's Clearwater compressor station interrupted gas flows. TCPL recently advised industry that repair work on one of the two Clearwater compressors is complete and returned to service; however, at the present time transportation curtailments are still in effect due to the upstream James River outages as well as routine maintenance work that TCPL had delayed as a result of both James River and Clearwater outages. The Company estimates approximately 700 boe per day in Ferrier remains restricted due to pipeline curtailments.

Petrus did not invest significant capital in its three other core areas in the third quarter of 2015; however, the Company has plans for additional development opportunities in those areas as commodity prices improve.

MANAGEMENT'S DISCUSSION & ANALYSIS

The following is management's discussion and analysis ("MD&A") of the financial and operating results of the Company as at and for the three and nine month periods ended September 30, 2015. This report is dated November 19, 2015 and should be read in conjunction with the September 30, 2015 interim condensed financial statements as well as the December 31, 2014 annual financial statements. Readers are directed to the advisories at the end of this report regarding forward-looking statements, BOE presentation and non-IFRS measures.

FINANCIAL AND OPERATIONAL RESULTS OF OIL AND NATURAL GAS ACTIVITIES

	Three months ended Sep. 30, 2015	Three months ended Sep. 30, 2014	Three months ended June 30, 2015	Three months ended Mar. 31, 2015	Three months ended Dec. 31, 2014
Quarterly average production					
Natural gas (mcf/d)	32,505	17,557	33,103	31,525	34,626
Oil (bbl/d)	2,616	1,799	2,811	3,559	2,998
NGLs (bbl/d)	634	203	560	519	1,053
Total (boe/d)	**8,668**	**4,928**	**8,890**	**9,333**	**9,822**
Total (boe)	797,439	453,359	808,947	839,927	903,620
Revenue (000s)					
Natural Gas	8,718	6,830	8,734	8,857	12,639
Oil	12,254	15,811	16,568	15,176	19,742
NGLs	942	951	1,274	1,391	3,194
Commodity revenue	21,914	23,592	26,576	25,424	35,575
Royalty revenue	77	128	65	72	423
Oil and natural gas revenue	21,991	23,720	26,641	25,496	35,998
Average realized prices					
Natural gas ($/mcf)	2.92	4.23	2.90	3.12	3.97
Oil ($/bbl)	50.91	95.51	64.76	47.38	67.47
NGLs ($/bbl)	16.14	51.08	24.99	29.77	47.52
Total ($/boe)	27.48	52.04	32.85	30.27	39.37
Hedging gain (loss)	4.72	(3.00)	3.58	5.81	3.73
Total realized ($/boe)	32.20	49.04	36.43	36.08	43.10
Average benchmark prices	**Three months ended Sep. 30, 2015**	**Three months ended Sep. 30, 2014**	**Three months ended June 30, 2015**	**Three months ended Mar. 31, 2015**	**Three months ended Dec. 31, 2014**
Natural gas					
AECO (C$/mcf)	2.91	4.19	2.64	2.74	3.61
Crude Oil					
Edm Lt. (C$/ bbl)	54.95	97.71	69.66	52.81	75.44
Foreign Exchange					
US$/C$	0.76	0.92	0.81	0.81	0.88

OIL AND NATURAL GAS REVENUE

Average production for the third quarter of 2015 was 8,668 boe per day (62% natural gas), compared to 4,928 boe per day (59% natural gas) for the third quarter of the prior year. Total commodity revenue decreased from $23.7 million in the third quarter of 2014 to $22.0 million in the comparative period of 2015. Average production for the first nine months of 2015 was 8,964 boe per day (60% natural gas), compared to 4,755 boe per day (55% natural gas) for the prior year comparative period. Total commodity revenue decreased from $76.7 million in the first nine months of 2014 to $74.1 million in the same period in 2015.

Natural gas

During the three months ended September 30, 2015, the benchmark natural gas price in Canada (set at the AECO hub) decreased by 31% from the prior year (average price of $2.91 per mcf in the third quarter of 2015 compared to $4.19 per mcf in the third quarter of the prior year). The Company's average realized gas price during the third quarter of 2015 was $2.92 per mcf compared to $4.23 per mcf in the third quarter of the prior year, which represents a 31% decrease. Natural gas revenue for the third quarter of 2015 was $8.7 million and production of 2,990,452 mcf accounted for approximately 19% of third quarter production volume and 40% of commodity revenue (compared to revenue of $6.8 million and production of 1,615,228 mcf for 59% of production volume and 29% of commodity revenue in the third quarter of the prior year).

Natural gas revenue for the first nine months of 2015 was $26.3 million and production of 8,840,075 mcf accounted for approximately 60% of production volume in the period and 35% of commodity revenue (compared to revenue of $21.7 million and production of 4,301,788 mcf for 55% of production volume and 29% of commodity revenue in the first nine months of the prior year).

Crude oil and condensate

Edmonton Light Sweet ("Edmonton") crude oil prices decreased 44% from the third quarter of 2014 to the third quarter of 2015 ($54.95 per bbl for the third quarter of 2015 compared to an average price of $97.71 per bbl for the prior period). The average realized price of Petrus' crude oil and condensate was $50.91 per bbl for the third quarter of 2015 compared to $95.51 per bbl for the same period in the prior year. Oil and condensate revenue for the third quarter of 2015 was $12.3 million and production of 240,685 bbl accounted for approximately 9% of total production volume and 56% of commodity revenue (compared to revenue of $15.8 million and production of 165,463 bbl for 37% of total production volume and 67% of commodity revenue in the third quarter of the prior year).

Oil and condensate revenue for the first nine months of 2015 was $44.0 million and production of 816,796 accounted for approximately 33% of total production volume and 60% of commodity revenue (compared to revenue of $52.2 million and production of 540,615 for 42% of total production volume and 69% of commodity revenue in the first nine months of the prior year).

Natural gas liquids (NGLs)

Petrus' NGL production mix consists of ethane, propane, butane, pentane and sulphur. The pricing received for Petrus' NGL production is based on the product mix, the fractionation process required and the demand for fractionation facilities. In the third quarter of 2015, Petrus' overall realized NGL price averaged $16.14 per bbl compared to $51.08 per bbl in the prior year. NGL revenue for the third quarter of 2015 was $0.9 million and production of 58,336 bbl accounted for approximately 2% of the Company's production volume and 4% of commodity revenue in the third quarter (compared to revenue of $1.0 million and production of 18,691 bbl for 4% of total production and 4% of commodity revenue for the third quarter of the prior year).

NGL revenue for the first nine months of 2015 was $3.8 million and production of 156,006 bbl accounted for approximately 7% of production volume and 5% of commodity revenue in the period (compared to revenue of $2.0 million and production of 40,618 bbl for 3% of total production volume and 4% of commodity revenue in the first nine months of the prior year).

Royalty Revenue

Petrus records gross overriding royalty revenue for production related to land or mineral rights owned. The revenue is included in "Other Income" on the Company's Statement of Net Income (Loss) and Comprehensive Income (Loss). Royalty revenue earned in the third quarter was $0.1 million compared to $0.1 million in the comparative quarter of the prior year. Royalty revenue earned in the nine month period ended September 30, 2015 was $0.2 million compared to $0.7 million in the comparative period of the prior year.

NON-GAAP MEASURES

Petrus uses key performance indicators and industry benchmarks such as “operating netback,” “corporate netback,” and “net debt” to analyze financial and operating performance. These indicators are not defined by IFRS and therefore may not be comparative to performance measures presented by other companies. Management believes that in addition to net income, the aforementioned non-IFRS measurements are useful supplemental measures as they assist in the determination of the Company’s operating performance, leverage and liquidity. Investors should be cautioned, however, that these measures should not be construed as an alternative to both net income and net cash from operating activities, which are determined in accordance with IFRS, as indicators of the Company’s performance.

Operating Netback

Operating netback is a common non-GAAP metric 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 operating netback is calculated as realized price less royalties, operating and transportation expenses on a per unit basis.

Corporate Netback

Corporate netback is also a common non-GAAP metric used in the oil and gas industry which evaluates the Company’s profitability at the corporate level. It is calculated as the operating netback less cash general & administrative and finance expenses.

Net Debt

Working capital (net debt) is a non-IFRS measure and is calculated as current assets (excluding financial derivative assets) less current liabilities (excluding financial derivative liabilities) and bank debt. Petrus uses net debt as a key indicator of its leverage and strength of its balance sheet. The reconciliation of net debt, as defined, is as follows:

($000s)	**As at Sept. 30, 2015**	As at Sept. 30, 2014
Current assets (excluding financial derivative assets)	17,879	137,004
Less: current liabilities (excluding financial derivative liabilities)	(8,313)	(25,990)
Less: bank debt	(236,375)	(90,000)
Working capital (net debt)	**(226,809)**	**21,014**

FUNDS FROM OPERATIONS AND EARNINGS

Petrus generated funds from operations of $10.8 million during the quarter ended September 30, 2015 ($9.9 million during the third quarter of 2014). On a nine month basis, funds from operations were $38.1 million compared to $36.3 million in the prior year. Funds growth was fueled by production growth, offset by significantly lower commodity prices from the prior year.

The Company incurred a net loss of $19.1 million in the third quarter of 2015 (compared to net income of $7.5 million in the third quarter of the prior year). On a nine month basis, the Company incurred a net loss of $32.6 million in the first nine months of 2015 compared to net income of $15.8 million in the comparable period of 2014. The decrease in earnings on a three and nine month basis relate to the reduction in commodity prices from the prior year. Due to a decrease in forward commodity prices and recent transaction metrics, the Company recorded an impairment loss during the third quarter of $28.5 million.

The following table provides detail on the Company's funds from operations on a barrel of oil equivalent ("boe") basis.

	Nine months Ended Sep. 30, 2015		Nine months ended Sep. 30, 2014		**Three months Ended Sep. 30, 2015**		Three months ended Sep. 30, 2014	
	$000s	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**
Oil and natural gas revenue	73,913	28.37	75,988	58.54	21,914	27.48	23,592	52.04
Transportation	(4,263)	(1.64)	(3,153)	(2.43)	(1,142)	(1.43)	(1,303)	(2.87)
Net revenue	69,650	26.73	72,835	56.11	20,772	26.05	22,289	49.17
Royalty expense	(9,153)	(3.51)	(15,182)	(11.70)	(2,308)	(2.89)	(4,035)	(8.90)
Royalty revenue	214	0.08	719	0.55	77	0.10	128	0.28
Net oil and natural gas revenue	**60,711**	**23.30**	**58,372**	**44.96**	**18,541**	**23.26**	**18,382**	**40.55**
Operating expense (1)	(20,209)	(7.76)	(12,315)	(9.49)	(6,277)	(7.87)	(4,395)	(9.69)
Hedging gain (loss)	11,543	4.43	(4,287)	(3.30)	3,767	4.72	(1,359)	(3.00)
General & administrative(2)	(5,181)	(1.99)	(2,876)	(2.22)	(1,674)	(2.10)	(1,446)	(3.19)
Interest expense (3)	(8,746)	(3.36)	(2,248)	(1.74)	(3,519)	(4.41)	(1,304)	(2.88)
Funds flow from operations	**38,118**	**14.62**	**36,646**	**28.22**	**10,838**	**13.60**	**9,878**	**21.79**

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

(2) G&A expense is presented net of capitalized general & administrative costs. Please see the G&A section on page 10 in the September 30, 2015 MD&A.

(3) Interest expense is presented net of other income and non-cash deferred finance expense.

(000s except per share)	**Nine months Ended Sep. 30, 2015**	Nine months ended Sep. 30, 2014	**Three months Ended Sep. 30, 2015**	Three months ended Sep. 30, 2014
Funds flow from operations	**38,118**	36,646	**10,838**	9,878
Funds flow from operations/share(1)	**0.27**	0.38	**0.08**	0.09
Net Income (loss)	**(32,579)**	15,817	**(19,055)**	7,530
Net income (loss)/share (basic)	**(0.23)**	0.17	**(0.14)**	0.07
Common shares	**140,593**	140,458	**140,593**	140,458
Weighted average shares	**140,593**	95,311	**140,593**	108,212

RESULTS OF OPERATIONS

Royalty Expenses

Royalties are paid to the Government of Alberta and to gross overriding royalty owners. The following table shows the Company's quarterly royalty expenses by product category, based upon the primary product produced at the well.

Royalty Expenses ($000s)	**Nine months Ended Sep. 30, 2015**	Nine months ended Sep. 30, 2014	**Three months Ended Sep. 30, 2015**	Three months ended Sep. 30, 2014
Crown ($000s)	**5,140**	14,456	**1,256**	3,898
% of production revenue	**7%**	19%	**6%**	16%
Gross overriding[(1)]	**4,013**	726	**1,052**	137
Total (000s)	**9,153**	15,182	**2,308**	4,035

Total royalty expenses (net of royalty allowances and incentives) decreased from $4.0 million in the third quarter of 2014 to $2.3 million in the third quarter of 2015. On a nine month basis, total royalties paid decreased from $15.2 million in 2014 to $9.2 million in 2015. The decreases are the result of lower royalties paid as a result of lower commodity prices, in addition to higher gas royalty allowance recovered.

Gross overriding royalties increased from $0.1 million in the third quarter of 2014 to $1.1 million in the third quarter of 2015. Similarly, the royalties increased from $0.7 million in the first nine months of 2014 to $4.0 million in 2015. The increase is due to the properties acquired in the Central Alberta and Ferrier operating areas, which carry gross overriding royalty obligations.

Financial Instruments

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 has outstanding as at September 30, 2015:

Natural Gas Contract Period	Type	Daily Volume	Price (CAD$/GJ)
Oct. 1, 2015 to Oct. 31, 2015	Fixed price	3,000 GJ	$3.35/GJ
Oct. 1, 2015 to Oct. 31, 2015	Fixed price	2,000 GJ	$2.52/GJ
Oct. 1, 2015 to Oct. 31, 2015	Fixed price	6,000 GJ	$2.37/GJ
Oct. 1, 2015 to Oct. 31, 2015	Fixed price	4,000 GJ	$2.46/GJ
Oct. 1, 2015 to Dec. 31, 2015	Fixed price	4,000 GJ	$3.49/GJ
Oct. 1, 2015 to Dec. 31, 2015	Costless Collar	5,000 GJ	$3.50 – 3.63/GJ
Oct. 1, 2015 to Dec. 31, 2015	Fixed price	1,000 GJ	$2.97/GJ
Nov. 1, 2015 to Mar. 31, 2016	Fixed price	6,000 GJ	$3.74/GJ
Nov. 1, 2015 to Mar. 31, 2016	Fixed price	6,000 GJ	$2.87/GJ
Nov. 1, 2015 to Mar. 31, 2016	Fixed price	4,000 GJ	$2.96/GJ
Nov. 1, 2015 to Mar. 31, 2016	Fixed price	2,000 GJ	$3.03/GJ
Jan. 1, 2016 to Mar. 31, 2016	Fixed price	5,000 GJ	$3.26/GJ
Apr. 1, 2016 to Oct. 31, 2016	Fixed price	2,000 GJ	$2.93/GJ
Apr. 1, 2016 to Oct. 31, 2016	Fixed price	6,000 GJ	$2.75/GJ
Apr. 1, 2016 to Oct. 31, 2016	Fixed price	2,000 GJ	$2.85/GJ
Apr. 1, 2016 to Oct. 31, 2016	Fixed price	5,000 GJ	$2.91/GJ
Apr. 1, 2016 to Oct. 31, 2016	Costless collar	5,000 GJ	$2.50 – 3.15/GJ
Nov. 1, 2016 to Mar. 31, 2017	Fixed price	2,000 GJ	$3.38/GJ
Nov. 1, 2016 to Mar. 31, 2017	Fixed price	2,000 GJ	$3.31/GJ
Nov. 1, 2016 to Mar. 31, 2017	Fixed price	6,000 GJ	$3.21/GJ
Nov. 1, 2016 to Mar. 31, 2017	Costless collar	5,000 GJ	$2.75 – 3.75/GJ
Apr.1, 2017 to Oct. 31, 2017	Fixed price	7,000 GJ	$2.84/GJ

Crude Oil Contract Period	Type	Daily Volume	Price ($/Bbl)
Oct. 1, 2015 to Dec. 31, 2015	Fixed price	200 Bbl	WTI $CAD100.00/Bbl
Oct. 1, 2015 to Dec. 31,2015	Fixed Price	100 Bbl	WTI $CAD 95.50/Bbl
Oct. 1, 2015 to Dec. 31, 2015	Fixed Price	250 Bbl	WTI $97.80/Bbl
Oct. 1, 2015 to Dec. 31, 2015	Fixed Price	250 Bbl	WTI $92.50-103.50/Bbl
Oct. 1, 2015 to Dec. 31, 2015	Costless collar	700 Bbl	WTI $CAD39.00-70.00/Bbl
Jan. 1, 2016 to Dec. 31, 2016	Costless collar	700 Bbl	WTI $CAD70.00-75.75/Bbl
Oct. 1, 2015 to Dec. 31, 2015	Costless collar	500 Bbl	WTI $USD40.05-70.00/Bbl
Oct. 1, 2015 to Dec. 31, 2015	Costless collar	250 Bbl	WTI $USD40.00-71.00/Bbl
Jan. 1, 2016 to Mar. 31, 2016	Costless collar	250 Bbl	WTI $USD40.00-75.00/Bbl
Jan. 1, 2016 to Jun. 30, 2016	Fixed Price	250 Bbl	WTI $CAD77.70/Bbl
Jan. 1, 2016 to Jun. 30, 2016	Costless collar	250 Bbl	WTI $CAD70.00-83.40/Bbl
Jan. 1, 2016 to Dec. 31, 2016	Costless collar	250 Bbl	WTI $CAD70.00-82.30/Bbl
Jan. 1, 2016 to Dec. 31, 2016	Costless collar	700 Bbl	WTI $CAD70.00-75.75/Bbl
Jul. 1, 2016 to Sep. 30, 2016	Costless collar	250 Bbl	WTI $CAD70.00-84.00/Bbl
Oct. 1, 2016 to Dec. 31, 2016	Costless collar	250 Bbl	WTI $CAD70.00-85.00/Bbl
Jan. 1, 2017 to Mar. 31, 2017	Costless collar	500 Bbl	WTI $CAD70.00-78.00/Bbl
Jan. 1, 2017 to Jun. 30, 2017	Costless collar	500 Bbl	WTI $CAD70.00-78.40/Bbl

Electric Power Contract Period	Type	Annual Volume	Price (CAD)
Oct. 1, 2015 to Dec. 31, 2015	Fixed price	12,264 MW	$50.00/MWH

Subsequent to September 30, 2015, the Company entered into the following financial derivative contracts:

Natural Gas Contract Period	Type	Daily Volume	Price (CAD$/GJ)
Jan.1, 2016 to Mar. 31, 2017	Fixed price	4,000 GJ	$2.54/GJ
Apr.1, 2017 to Oct. 31, 2017	Fixed price	5,000 GJ	$2.64/GJ
Nov.1, 2017 to Mar. 31, 2018	Fixed price	5,000 GJ	$3.02/GJ

Crude Oil Contract Period	Type	Daily Volume	Price ($/Bbl)
Jan. 1, 2017 to Mar. 31, 2017	Costless collar	100 Bbl	WTI $CAD65.00-71.00/Bbl
Apr. 1, 2017 to Jun. 30, 2017	Costless collar	400 Bbl	WTI $CAD65.00-72.70/Bbl
Jul. 1, 2017 to Sep. 30, 2017	Costless collar	500 Bbl	WTI $CAD65.00-74.20/Bbl
Oct. 1, 2017 to Dec. 31, 2017	Costless collar	400 Bbl	WTI $CAD65.00-75.85/Bbl

The impact of the contracts which were settled during the reporting periods are recorded as realized hedging gains (losses) and affect the Company's realized commodity price. The unrealized gain (loss) is recorded to demonstrate the impact of the outstanding contracts had they settled on the relative financial reporting period date. The contracts entered had the following impact on net income (loss):

Other Income ($000s)	**Nine months Ended Sep. 30, 2015**	Nine months ended Sep. 30, 2014	**Three months Ended Sep. 30, 2015**	Three months ended Sep. 30, 2014
Realized hedging gain (loss)	**11,543**	(4,287)	**3,767**	(1,359)
Unrealized hedging gain (loss)	**(3,842)**	2,104	**5,205**	5,370
Total gain (loss) on derivatives	**7,701**	(2,183)	**8,972**	4,011

Weak commodity prices resulted in a third quarter realized hedging gain of $3.8 million, compared to a $1.4 million loss realized in the comparative quarter of the prior year. The third quarter realized gain increased the Company's realized price by $4.72 per boe, compared to a decrease in the prior year comparative period of $3.00 per boe. On a nine month basis the Company recorded a realized hedging gain of $11.5 million in 2015 relative to a $4.3 million realized loss in 2014.

For the three months ended September 30, 2015 the Company recorded a $5.2 million unrealized hedging gain compared to a $5.4 million gain in the prior comparative period. On a nine month basis the Company recorded an unrealized loss of $3.8 million and $2.1 million gain for 2015 and 2014, respectively.

Operating Expenses

The following table shows the Company's operating expenses for the reporting periods which are shown net of processing income and overhead recoveries:

Operating Expenses ($000s)	**Nine months Ended Sep. 30, 2015**	Nine months ended Sep. 30, 2014	**Three months Ended Sep. 30, 2015**	Three months ended Sep. 30, 2014
Operating expense, net [1]	**20,209**	12,315	**6,277**	4,395
Operating expense, net ($ per boe)	**7.76**	9.49	**7.87**	9.69

[1] Operating expenses are presented net of processing income and overhead recoveries

Operating expenses totaled $6.3 million for the third quarter of 2015, a 43% increase from $4.4 million recorded in the third quarter of the prior year. Operating costs in the third quarter of 2015 of $7.87 per boe were negatively impacted by the TCPL related transportation curtailments due to amortization of the fixed operating cost component over lower sales volumes. Despite the lower sales volumes, operating costs declined 19%, from $9.69 per boe in the third quarter of 2014. On a nine month basis operating expenses totaled $20.2 million in 2015 ($7.76 per boe) and $12.3 million ($9.49 per boe) in 2014. Petrus is currently constructing a gas plant in the Ferrier area in order to control and reduce costs and increase processing revenue. The plant will be connected directly to a sales pipeline and will be capable of NGL refrigeration and recovery in order to reduce the Company's reliance on third party processing. It is expected to be on stream in the fourth quarter of 2015.

Transportation Expenses

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

Transportation Expenses ($000s)	**Nine months Ended Sep. 30, 2015**	Nine months ended Sep. 30, 2014	**Three months Ended Sep. 30, 2015**	Three months ended Sep. 30, 2014
Transportation expense	**4,263**	3,153	**1,142**	1,303
Transportation expense ($ per boe)	**1.64**	2.43	**1.43**	2.87

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 expenses totaled $1.1 million or $1.43 per boe in the third quarter of 2015 ($1.3 million or $2.87 per boe for the comparative period of the prior year). On a nine month basis transportation expenses totaled $4.3 million in 2015 ($1.64 per boe) and $3.2 million ($2.43 per boe) in 2014. The reduction in transportation expenses from the prior year is attributed to a reduction in trucked volumes as a higher proportion of the Company's commodities were sold via pipeline in 2015.

General and Administrative Expenses

The following table illustrates the Company's general and administrative expenses which are shown net of capitalized costs directly related to exploration and development activities:

General and Administrative Expenses ($000s)	**Nine months Ended Sep. 30, 2015**	Nine months ended Sep. 30, 2014	**Three months Ended Sep. 30, 2015**	Three months ended Sep. 30, 2014
Gross general and administrative expense	**6,697**	4,650	**2,244**	2,092
Capitalized general and administrative	**(1,516)**	(1,775)	**(570)**	(647)
Net general and administrative expense	**5,181**	2,876	**1,674**	1,446
Share based compensation expense	**936**	1,024	**112**	378
Capitalized share based compensation	**(355)**	(512)	**(25)**	(189)
Total general and administrative expense, net	**5,762**	3,388	**1,761**	1,634
Total ($ per boe)	**2.21**	2.61	**2.21**	3.61

Third quarter 2015 net general and administrative expenses (excluding non-cash share based compensation), totaled $1.7 million or $2.10 per boe (compared to $1.4 million or $1.96 per boe for the third quarter of 2014). On a nine month basis, net general and administrative expenses totaled $5.2 million ($1.99 per boe) in 2015 (compared to $2.9 million or $1.53 per boe for the comparable period of 2014). The increase, on a per boe basis, is attributed to the Company's growth, combined with lower than expected third quarter production. G&A costs in the third quarter of 2015 were negatively impacted by the TCPL related transportation curtailments due to amortization of the fixed administrative cost component over lower sales volumes.

As a result of the significant decline in commodity prices Petrus reorganized corporate and field personnel responsibilities which led to a reduction in the number of employees and contractors. All other compensation was also reduced which came into effect in the fourth quarter. The changes will result in G&A and operating cost savings of approximately $0.35 per boe and $0.25 per boe, respectively.

Petrus capitalizes and reclassifies those general and administrative expenses which are directly attributable to the acquisition, exploration and development activities of the Company which pertain to salaries and benefits of technical staff responsible for exploration and development activities.

Finance

The following table illustrates the Company's finance expenses:

Finance Expenses ($000s)	**Nine months Ended Sep. 30, 2015**	Nine months ended Sep. 30, 2014	**Three months Ended Sep. 30, 2015**	Three months ended Sep. 30, 2014
Interest expense	**8,851**	2,181	**3,552**	1,280
Non-cash deferred finance expense	**654**	75	**316**	25
Accretion	**908**	415	**310**	161
Total finance expense	**10,413**	2,671	**4,178**	1,466

The Company incurs cash interest expense on its bank indebtedness (revolving credit facility) and long term debt (term loan). For the third quarter of 2015 the Company incurred $3.6 million of cash interest expense, compared to $1.3 million in the prior year. On a nine month basis cash interest expense was $8.9 million in 2015 compared to $2.2 million in 2014. The increases are attributed to increased debt issued in the fourth quarter of 2014 in conjunction with the corporate acquisitions of Arriva and Ravenwood. The Company amortizes the upfront debt fees over the term of the borrowings (non-cash). For the three and nine months ended September 30, 2015, the Company recorded $0.3 million and $0.7 million, respectively ($0.03 million and $0.08 million for the three and nine months, respectively ended September 30, 2014). Accretion expense is incurred to recognize the passage of time of the decommissioning obligation (non-cash). For the three and nine months ended September 30, 2015, the Company recorded $0.3 million and $0.9 million, respectively, compared to $0.2 million and $0.4 million for the comparative periods of 2014. The increases are due to the increased decommissioning obligation associated with assets acquired and developed.

Depletion and Depreciation

The following table illustrates depletion and depreciation expenses recorded in the reporting periods:

Depletion and Depreciation ($000s)	**Nine months Ended Sep. 30, 2015**	Nine months ended Sep. 30, 2014	**Three months Ended Sep. 30, 2015**	Three months ended Sep. 30, 2014
Depletion	**42,252**	18,198	**12,163**	6,858
Depreciation	**108**	33	**44**	17
Total	**42,360**	18,231	**12,207**	6,875
Depletion ($ per boe)	**16.21**	14.02	**15.22**	15.13
Depreciation ($ per boe)	**0.04**	0.02	**0.06**	0.04
Total ($ per boe)	**16.25**	14.04	**15.28**	15.17

Depletion and depreciation expense is calculated on a unit-of-production 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 costs. 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 expense in the third quarter of 2015 of $12.1 million or $15.22 per boe, compared to the third quarter of 2014, when $6.9 million or $15.13 per boe was recorded. On a nine month basis depletion expense was $42.2 million ($16.21 per boe) in 2015 and $18.2 million ($14.02 per boe) in 2014. The Company's depletion expense has increased from the prior year due to the increased production and reserves base. Depreciation expense is not significant as most depreciable assets were fully depreciated in the prior year.

Impairment

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

Impairment ($000s)	**Nine months Ended Sep. 30, 2015**	Nine months ended Sep. 30, 2014	**Three months Ended Sep. 30, 2015**	Three months ended Sep. 30, 2014
Impairment	**28,541**	–	**28,541**	–
Total	**28,541**	–	**28,541**	–

At September 30, 2015, due to a decrease in forward commodity prices and recent transaction metrics, the Company determined that indicators of impairment exist and therefore, an impairment test was performed for all of the Company's CGUs. The recoverable value of the Company's CGU's was estimated as the fair value less costs to sell based on the net present value of before tax cash flows from crude oil and natural gas proved plus probable reserves originally estimated by third party reserve evaluators and internally updated for production since December 31, 2014 plus an internal estimate of incremental development drilling locations and a discount rate of 12%. The Company recorded property, plant and equipment impairments of $28.5 million on two of its four CGUs (Peace River - $8.8 million; and Foothills - $19.7 million). The recoverable amount for the two CGUs was as follows: Peace River - $47.5 million; and Foothills - $108.4 million.

SHARE CAPITAL

The authorized share capital consists of an unlimited number of common voting shares without par value. As at September 30, 2015 the Company had 6,293,333 and 6,274,270 stock options and performance warrants outstanding, respectively. As at September 30, 2015 the Company had 140,592,598 common shares outstanding. The following table details the number of issued and outstanding instruments for the financial periods shown:

(000s)	**Nine months Ended Sep. 30, 2015**	Nine months ended Sep. 30, 2014	**Three months Ended Sep. 30, 2015**	Three months ended Sep. 30, 2014
Weighted average outstanding common shares				
Basic	**140,593**	95,312	**140,593**	108,212
Diluted[(1)]	**140,593**	100,172	**140,593**	113,072
Outstanding instruments				
Common shares	**140,593**	140,458	**140,593**	140,458
Stock options	**6,208**	5,955	**6,208**	5,955
Warrants	**6,274**	6,408	**6,274**	6,408

[(1)] *In order to calculate the diluted number of common shares outstanding for the three and nine months ended September 30, 2015, all warrants and stock options were considered; however no instruments were included as their impact is anti-dilutive. For the three and nine months ended September 30, 2014, 768,027 warrants and 2,068,846 stock options were added to the calculation as their impact is dilutive.*

LIQUIDITY AND CAPITAL RESOURCES

(a) Bank Indebtedness

On May 31, 2015 the Company renewed its existing syndicated credit facility and structured a $200 million facility comprised of a $20 million operating facility, a $160 million syndicated term-out facility and a $20 million non-borrowing base facility, (altogether the "Revolving Credit Facility " or "RCF"). The term-out facility has a revolving period that ends July 29, 2016 at which time it will either be renewed or converted to a one-year term facility. The non-borrowing base facility requires the prior written consent of the lenders before amounts can be drawn by the Company; therefore, at September 30, 2015, the amount available under the RCF was $180 million (December 31, 2014 - $200 million). The RCF bears interest at Canadian bank prime, or at the Company's option, Canadian bankers' acceptances, plus applicable margin and stamping fee. The stamping fees range, depending on Petrus' debt to EBITDA ratio (which is: earnings before interest, taxes, depreciation and amortization as defined in the banking agreement), between 100 bps and 250 bps on Canadian bank prime borrowings and between 200 bps and 350 bps on Canadian dollar bankers' acceptances. The undrawn portion of the RCF, are subject to a standby fee in the range of 50 bps to 87.50 bps.

At September 30, 2015, the Company had a $2.4 million letter of credit outstanding against the RCF (December 31, 2014; Nil) and had drawn $143 million against the RCF (December 31, 2014; $100.0 million).

The amount of the RCF is subject to a borrowing base review performed on a semi-annual basis by the lender, based primarily on reserves and commodity prices estimated by the lenders as well as other factors. A decrease in the borrowing base could result in a reduction to the available credit under the RCF. Subsequent to the end of the third quarter the borrowing base was reviewed and reduced to $160 million. The Company has provided collateral by way of a $600 million debenture over all of the present and after acquired property of the Company.

The RCF carries a financial covenant which limits the Company's ability to borrow amounts greater than the RCF limit as well as:

(a) a financial covenant of PV10 to Net Secured Debt Ratio being less than 1.25 to 1.00 whereby Net Secured Debt (as defined by the banking agreement) means all amounts owing under the Credit Facility and any other secured debt of Petrus on a consolidated basis, minus restricted cash and cash equivalents and "PV10" means the discounted net present value (at a discount rate of 10%) of Petrus' proved reserves, as adjusted for commodity swaps then in effect and
(b) certain financial covenants only when any indebtedness under the Term Loan (note 6b) remain outstanding which are:
    a. The Working Capital Ratio will not be less than 1.00 to 1.00;
    b. The Proved Asset Coverage Ratio will not be less than 1.25 to 1.00; and
    c. The PDP Asset Coverage Ratio will not be less than 1.00 to 1.00.

Under the agreement, for purposes of the Working Capital Ratio, current assets are the current assets under IFRS 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. Current liabilities are the current liabilities under IFRS, 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, including the term loan debt.

At September 30, 2015 the Company was in compliance with all covenants under the revolving credit facility.

(b) Long Term Debt

The Company has a $90 million second lien term loan facility (the "Term Loan") which matures and is repayable on October 1, 2016. Interest is due and payable monthly and accrues at a per annum rate of (three-month) the Canadian Dealer offered Rate (CDOR) plus 700 basis points. The Term Loan is subject to three financial covenants: (1) the same financial covenant of PV10 to Net Secured Debt Ratio being not less than 1.25 to 1.00 as the Revolving Credit Facility (note 6a); (2) a covenant that Petrus may not, as of the effective date of each annual independent engineering reserve report and each internally prepared semi-annual internally prepared reserve report, permit the PDP to Net Secured Debt Ratio to be less than 1.00 to 1.00 where "PDP" means the present value (discounted at 10.0%) of future net revenues attributable to Petrus' PDP reserves and (3) Petrus' working capital ratio (current assets to current liabilities will not be less than 1.0 to 1.0.

Under the agreement, current assets are the current assets under IFRS plus any undrawn availability under the Revolving Credit Facility, 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. Current liabilities are the current liabilities under IFRS, 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, including the term loan debt.

The Term Loan is secured with a $250 million second lien priority interest on the same collateral as the Credit Facilities and requires a certain level of production volume to be hedged in 2015 and 2016. At September 30, 2015 the Company was in compliance with all covenants of the term loan.

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. The Company's objectives when managing capital are (i) to manage financial flexibility in order to preserve the Company's ability to meet financial obligations; (ii) maintain a capital structure that allows Petrus the ability to finance its growth using internally generated cash flow, and (iii) to maintain a flexible capital structure which optimizes the cost of capital at an acceptable risk level and provides an optimal return to equity holders.

In the management of capital, Petrus includes share capital and total net debt, which is made up of debt and working capital (current assets less current liabilities). Petrus 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. Petrus anticipates that it will have adequate liquidity to fund future working capital and forecasted capital expenditures in 2015 through a combination of cash flow, current working capital and use of its credit facility. Petrus does not have any capital commitments and is able to modify its capital program in response to changes in commodity prices and cash flows. Should the Company choose to expand its capital program, actual funding alternatives would be required. Management is currently considering a number of options, including financings, asset sales and an extension of the term loan, to ensure it has sufficient capital to meet its short and medium term commitments and objectives.

CAPITAL EXPENDITURES

Petrus invested $9.0 million in total capital expenditures in the third quarter of 2015 (compared to $142.6 million in the third quarter of the prior year). The investments were funded by cash flow from operations and the Company's credit facility. The Company's expenditures were invested in completions, workovers, tie-ins and construction of a new gas processing facility in the Ferrier area.

During the nine month period ended September 30, 2015 Petrus invested $48.7 million. In the nine month period ended September 30, 2014, $194.8 million was invested. The following table shows capital expenditures for the reporting periods indicated. All capital is presented before decommissioning obligations and settlements and excludes non-cash capitalized share based compensation:

($000s)	**Nine months Ended Sep. 30, 2015**	Nine months ended Sep. 30, 2014	**Three months Ended Sep. 30, 2015**	Three months ended Sep. 30, 2014
Drill and complete	**27,258**	39,005	**4,045**	20,155
Oil and gas equipment	**18,529**	18,044	**4,127**	6,119
Geological	**302**	1,428	**1**	1,389
Land and lease	**106**	1,018	**56**	397
Office	**227**	272	**241**	68
Capitalized general and administrative	**1,290**	2,287	**571**	836
Total	**47,939**	62,054	**9,041**	28,964
Acquisitions/(dispositions)	**938**	132,719	–	113,605
Total capital	**48,650**	194,773	**9,041**	142,569
Gross (net) wells spud	**6 (5.9)**	29 (18.9)	–	16 (11.1)

SUMMARY OF QUARTERLY RESULTS

($000s) except per share amounts	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2014	Sep. 30, 2014	Jun. 30, 2014	Mar. 31, 2014	Dec. 31, 2013
	Three months ended							
Oil and natural gas revenue	**21,914**	**26,576**	25,423	35,574	23,592	26,815	25,581	16,939
Transportation	(1,142)	(1,561)	(1,560)	(1,126)	(1,303)	(979)	(872)	(543)
Net revenue	**20,772**	**25,015**	**23,863**	**34,448**	**22,289**	**25,836**	**24,709**	**16,396**
Royalty expense (1)	(2,308)	(3,020)	(3,825)	(3,958)	(4,035)	(5,760)	(5,387)	(2,372)
Royalty income (1)	77	65	72	423	128	303	288	155
Net oil and natural gas revenue	18,541	22,060	20,110	30,913	18,382	20,379	19,610	14,179
Operating expense (2)	(6,277)	(7,396)	(6,536)	(5,815)	(4,395)	(4,194)	(3,727)	(3,716)
Hedging gain (loss)	3,767	2,894	4,881	3,371	(1,359)	(1,496)	(1,432)	(409)
General and administrative expense (3)	(1,674)	(1,843)	(1,664)	(2,117)	(1,446)	(797)	(634)	(582)
Interest expense (4)	(3,552)	(3,166)	(2,256)	(1,725)	(1,304)	(614)	(335)	(252)
Funds from operations	**10,838**	**12,549**	**14,535**	**24,627**	**9,878**	**13,278**	**13,482**	**9,220**
Per share – basic	0.08	0.09	0.10	0.18	0.09	0.15	0.16	0.11
Net income (loss)	**(19,055)**	**(7,239)**	**(6,312)**	**(63,308)**	**7,530**	**5,505**	**2,208**	**2,086**
Per share – basic	(0.14)	(0.05)	(0.05)	(0.45)	0.07	0.06	0.03	0.02
Common shares (000s)	**140,593**	**140,593**	**140,593**	**140,593**	**140,458**	**101,748**	**86,377**	**86,377**
Weighted average shares (000s)	140,593	140,593	140,593	140,571	108,212	91,106	86,377	86,377
Total assets	595,890	627,808	641,547	647,304	549,248	259,110	257,245	211,952
Net working capital (net debt)	**(226,809)**	**(228,562)**	**(227,607)**	**(215,049)**	**21,014**	**415**	**(51,638)**	**(22,288)**

(1) The Company re-classified gross overriding royalty expense from other income to royalty expenses in the Statement of Net Income and Comprehensive Income. The comparative information has been re-classified to conform to current presentation.
(2) Operating expenses are presented net of processing income and overhead recoveries.
(3) General and administrative expense is presented net of capitalized G&A.
(4) Interest expense is presented net of other income and non-cash deferred finance expense.

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 and production levels.

Petrus' production has continually grown over the last two years. Average quarterly production has increased, from 3,658 boe per day in the fourth quarter of 2013 to 8,668 boe per day in the third quarter of 2015. The production growth was equally attributable to the Company's exploration and development activities and acquisitions of producing properties.

The Company's funds from operations were $9.2 million in the fourth quarter of 2013 and $10.8 million in the third quarter of 2015. Funds from operations have increased over the two year time period with higher production levels despite weakened commodity prices in the current year. Commodity price improvements can enable higher reinvestment in exploration, development and acquisition activities in future periods as they increase the funds received from operations. 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' reinvestment in future reserves will be dependent on its ability to obtain debt and equity financing as well as the funds it receives from operations.

OTHER TRANSACTIONS

The Company is not party to any material related party or off balance sheet transactions.

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, petroleum and natural gas assets are aggregated into cash-generating units ("CGU's"), based on separately identifiable and largely independent cash inflows. The determination of the Company's CGU's 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 values less costs to sell. 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 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.

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. Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable income available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in income or loss in the period in which the change occurs. Additionally, future 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.

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.

ACCOUNTING POLICIES AND NEW STANDARDS

Significant accounting policies
The Company's significant accounting policies can be read in note 3 to the Company's audited financial statements as at and for the year ended December 31, 2014.

ADVISORIES

Basis of Presentation
Financial data presented below have largely been derived from the Company's financial statement, prepared in accordance with International Financial Reporting Standards ("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, 2014. 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 document, including management's assessment of the Company's future plans and operations, 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 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; 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; future land expiries; dispositions and joint venture arrangements; amount of operating, transportation and general and administrative expenses; treatment under governmental regulatory regimes and tax laws; estimated tax pool balances and anticipated IFRS elections and the impact of the conversion to IFRS. In addition, statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

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

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

BOE Presentation

The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent ("BOE") basis whereby natural gas volumes are converted at the ratio of nine 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 equivalency of the two commodities at the burner tip. However, BOE's do not represent an economic value equivalency at the wellhead and therefore may be a misleading measure if used in isolation.

Abbreviations

000's	*thousand dollars*
bbl	*barrel*
bbl/d	*barrels per day*
bcf	*billion cubic feet*
boe/d	*barrel of oil equivalent per day*
CAD	*Canadian dollar*
GJ	*gigajoule*
GJ/d	*gigajoules per day*
mbbls	*thousand barrels*
mboe	*thousand barrels of oil equivalent*
mcf	*thousand cubic feet*
mcf/d	*thousand cubic feet per day*
mmbbls	*million barrels*
mmboe	*millions of barrels of oil equivalent*
mmcf	*million cubic feet*
mmcf/d	*million cubic feet per day*
NGLs	*natural gas liquids*
USD	*United States dollar*
WTI	*West Texas Intermediate*

Cover page photo credit: Alain Sleigher Photography

BALANCE SHEETS
(UNAUDITED)

(Expressed in 000's of Canadian dollars)

As at	September 30, 2015	December 31, 2014
ASSETS		
Current		
Cash	—	19,524
Deposits and prepaid expenses	870	1,042
Accounts receivable	17,009	23,336
Risk management asset *(note 8)*	10,763	14,609
	28,642	**58,511**
Non-current		
Exploration and evaluation assets *(notes 3 and 4)*	92,211	94,073
Property, plant and equipment *(notes 3 and 5)*	475,037	494,720
	567,248	588,793
	595,890	**647,304**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	8,313	69,831
Risk management liability *(note 8)*	192	197
	8,505	**70,028**
Non-Current		
Bank indebtedness *(note 6)*	146,459	99,710
Long term debt *(note 6)*	89,916	89,409
Decommissioning obligation *(note 7)*	63,392	58,634
Deferred income tax liability	7,500	17,763
	315,772	**335,544**
Shareholders' Equity		
Share capital *(note 9)*	346,106	346,106
Contributed surplus	6,381	5,445
(Deficit)	(72,369)	(39,791)
	280,118	**311,760**
	595,890	**647,304**

Commitments (note 14)
Subsequent events (note 15)
See accompanying notes to the condensed interim financial statements

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

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

	Three months ended Sept. 30, 2015	Three months ended Sept. 30, 2014	Nine months ended Sept. 30, 2015	Nine months ended Sept. 30, 2014
REVENUE				
Oil and natural gas revenue	21,991	23,721	74,128	76,708
Royalty expense	2,308	4,035	9,153	15,182
Oil and natural gas revenue, net of royalties	**19,683**	**19,686**	**64,975**	**61,526**
Other income	33	—	105	8
Gain (loss) on disposition *(note 3)*	—	2,175	(52)	2,175
Gain (loss) on financial derivatives *(note 8)*	8,972	4,011	7,701	(2,183)
	28,688	**25,872**	**72,729**	**61,526**
EXPENSES				
Operating *(note 11)*	6,277	4,395	20,209	12,315
Exploration and evaluation expense *(note 4)*	816	126	4,020	126
Transportation expenses	1,142	1,303	4,263	3,153
General and administrative *(note 12)*	1,674	1,446	5,181	2,876
Share-based compensation *(note 9)*	87	189	581	512
Finance	4,178	1,466	10,413	2,671
Depletion and depreciation *(note 5)*	12,207	6,875	42,360	18,231
Impairment *(note 5)*	28,541	—	28,541	—
	54,922	**15,800**	**115,568**	**39,884**
NET INCOME (LOSS) BEFORE INCOME TAXES	**(26,234)**	**10,072**	**(42,841)**	**21,642**
Current tax expense	—	—	—	—
Deferred income tax expense (recovery)	(7,179)	2,543	(10,262)	5,824
	(7,179)	2,543	(10,262)	5,824
TOTAL NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	**(19,055)**	**7,529**	**(32,579)**	**15,818**
Net income (loss) per common share *(note 10)*				
Basic	**(0.14)**	**0.07**	**(0.23)**	**0.17**
Diluted	**(0.14)**	**0.07**	**(0.23)**	**0.16**

See accompanying notes to the condensed interim financial statements

STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (UNAUDITED)

(Expressed in 000's of Canadian dollars)

	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Total
Balance, December 31, 2013	**144,339**	**3,962**	**7,701**	**156,002**
Net income (loss)	—	—	15,817	15,817
Issuance of common shares	205,031	—	—	205,031
Premium liability of flow-through shares	(235)	—	—	(235)
Share-based compensation	—	1,024	—	1,024
Share issue costs	(4,759)	—	—	(4,759)
Tax effect of share issue costs	1,190	—	—	1,190
Balance, September 30, 2014	**345,566**	**4,986**	**23,518**	**374,070**
Balance, December 31, 2014	**346,106**	**5,445**	**(39,791)**	**311,760**
Net income (loss)	—	—	(32,579)	(32,579)
Share-based compensation *(note 9)*	—	936	—	936
Balance, September 30, 2015	**346,106**	**6,381**	**(72,370)**	**280,117**

See accompanying notes to the condensed interim financial statements

STATEMENTS OF CASH FLOWS
(UNAUDITED)

(Expressed in 000's of Canadian dollars)

Funds generated by (used in):	**Three months ended Sept. 30, 2015**	**Three months ended Sept. 30, 2014**	**Nine months ended Sept. 30, 2015**	**Nine months ended Sept. 30, 2014**
OPERATING ACTIVITIES				
Net income (loss)	**(19,055)**	**7,530**	**(32,579)**	**15,817**
Adjust items not affecting cash:				
Share-based compensation *(note 9)*	87	189	581	512
Unrealized hedging (gains) losses *(note 8)*	(5,204)	(5,370)	3,842	(2,105)
Finance expenses	625	161	1,562	415
Depletion and depreciation *(note 5)*	12,207	6,875	42,360	18,231
Impairment *(note 5)*	28,541	—	28,541	—
Exploration and evaluation expense *(note 4)*	816	126	4,020	126
Loss (gain) on disposition *(note 3)*	—	(2,175)	53	(2,175)
Deferred income tax expense (recovery)	(7,179)	2,543	(10,262)	5,824
Decommissioning expenditures	—	—	(571)	(349)
Funds generated by operations	**10,838**	**9,879**	**37,547**	**36,296**
Change in operating non-cash working capital	303	1,501	(30,779)	330
Cash flow generated by (used in) operating activities	**11,141**	**11,380**	**6,768**	**36,626**
FINANCING ACTIVITIES				
Issuance of common shares *(note 9)*	—	155,000	—	205,031
Share issue costs *(note 9)*	—	(2,915)	—	(4,759)
Increase (decrease) in bank indebtedness	5,502	90,000	47,507	66,620
Cash generated by financing activities	**5,502**	**242,085**	**47,507**	**266,892**
INVESTING ACTIVITIES				
Property and equipment (acquisitions) dispositions *(note 3)*	—	(10,605)	(938)	(29,718)
Corporate (acquisitions) dispositions *(note 3)*	—	(103,000)	—	(103,000)
Exploration and evaluation asset expenditures *(note 4)*	(560)	(2,314)	(1,384)	(3,437)
Petroleum and natural gas property expenditures *(note 5)*	(7,965)	(26,446)	(46,101)	(57,910)
Other capital expenditures	(241)	(68)	(227)	(272)
Change in investing non-cash working capital	(7,877)	9,550	(25,149)	12,017
Cash generated by (used in) investing activities	**(16,643)**	**(132,883)**	**(73,799)**	**(182,320)**
Increase (decrease) in cash	—	120,580	**(19,524)**	121,199
Cash, beginning of period	—	619	**19,524**	—
Cash, end of period	**—**	**121,199**	**—**	**121,199**
Cash interest paid	3,699	51	8,998	747
Cash taxes paid	—	—	—	—

See accompanying notes to the condensed interim financial statements

CONDENSED NOTES TO THE INTERIM FINANCIAL STATEMENTS (UNAUDITED)

1. NATURE OF THE ORGANIZATION

Petrus Resources Ltd. (“Petrus” or the “Company”) is a privately held entity which was incorporated under the laws of the Province of Alberta on December 13, 2010. On October 8, 2014 Petrus amalgamated with its two wholly owned subsidiaries, Arriva Energy Inc. and Ravenwood Energy Corp.

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

These financial statements report the financial position and the results of operations for the three and nine months ended September 30, 2015 and prior year comparative periods and were approved by the Company’s Board of Directors on November 19, 2015.

2. BASIS OF PRESENTATION

(a) Statement of Compliance

These condensed interim financial statements have been prepared by management on a historical basis, except for certain financial instruments that have been measured at fair value. These condensed interim financial statements have been prepared in accordance with International Accounting Standard 34 “Interim Financial Reporting.” Certain information and disclosures normally included in the notes to the annual financial statements have been condensed. Accordingly, these condensed interim financial statements should be read in conjunction with the annual financial statements for the year ended December 31, 2014, which were prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”). The preparation of these condensed interim financial statements requires the use of certain critical accounting estimates and also requires management to exercise judgment in applying the Company’s accounting policies. In preparing these condensed interim financial statements, the significant judgments made by management in applying the Company’s accounting policies and key sources of estimation uncertainty were the same as those applied to the financial statements for the year ended December 31, 2014. The condensed interim financial statements have been prepared following the same accounting policies as the financial statements for the year ended December 31, 2014. These condensed interim financial statements are presented in Canadian dollars, except where otherwise noted.

3. ACQUISITIONS

Business combination

On January 20, 2015 Petrus closed an acquisition of petroleum and natural gas assets in the Ferrier area of Alberta, for total cash consideration of $4.4 million, net of adjustments. The transaction was accounted for as a business combination using the acquisition method whereby the net assets acquired and the liabilities assumed are recorded at fair value. The acquisition was financed by way of the Company’s revolving credit facility. Acquisition related costs, which relate to professional fees, are charged to finance expenses in the Statement of Net Income (Loss).

Petrus obtained resource tax pools equal to the total net assets acquired of $4.4 million.

The following table summarizes the net assets acquired pursuant to the acquisition:

Fair value of net assets acquired $000s	
Exploration and evaluation assets	1,136
Petroleum and natural gas properties and equipment	3,313
Decommissioning obligations	(91)
Total net assets acquired	**4,358**

Property disposition

On February 6, 2015 Petrus closed the disposition of non-core petroleum and natural gas assets in the Pembina area of Alberta for total cash consideration of $7.7 million after post-closing adjustments. The Company recorded a loss of $0.05 million on the divestiture during the nine months ended September 30, 2015.

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

Fair value of net assets disposed $000s	
Exploration and evaluation assets	(92)
Petroleum and natural gas properties and equipment	(8,125)
Decommissioning obligations	517
Loss on sale of assets	52
Total net assets disposed	**(7,648)**

Business combination

On February 6, 2015 Petrus closed an acquisition of petroleum and natural gas assets in the Ferrier area of Alberta for total cash consideration of $4.4 million, net of adjustments. The transaction was accounted for as a business combination using the acquisition method whereby the net assets acquired and the liabilities assumed were recorded at fair value. The acquisitions were financed by way of the Company's revolving credit facility. Acquisition related costs, which relate to professional fees, are charged to finance expenses in the Statement of Net Income (Loss).

Petrus obtained resource tax pools equal to the total net assets acquired of $4.4 million.

The following table summarizes the net assets acquired pursuant to the acquisition:

Fair value of net assets acquired $000s	
Exploration and evaluation assets	1,063
Petroleum and natural gas properties and equipment	3,921
Decommissioning obligations	(631)
Total net assets acquired	**4,353**

From the date of their respective acquisitions to September 30, 2015, the above business combinations contributed approximately $0.5 million of revenue and $0.4 million of operating income. If the acquisition had taken place at January 1, 2015, the proforma incremental revenue and operating income (defined as revenue, net of royalties, less operating and transportations costs) of the Company for the nine months ended September 30, 2015 would have been approximately $0.6 million and $0.4 million, respectively. The proforma information is not necessarily indicative of the results of operations that would have resulted had the acquisitions been effective on the dates indicated, or future results.

Property disposition

On May 7, 2015 Petrus closed the disposition of non-core exploration and evaluation assets in the Ferrier area of Alberta for total cash consideration of $0.1 million.

4. EXPLORATION AND EVALUATION ASSETS

The components of the Company's Exploration and Evaluation assets are as follows:

Balance, December 31, 2013	**50,529**
Additions	5,753
Property acquisitions	16,310
Corporate acquisitions	21,514
Exploration and evaluation expense	(1,158)
Capitalized G&A and share-based compensation	1,272
Transfers to property, plant and equipment	(147)
Balance, December 31, 2014	**94,073**
Additions	626
Property acquisitions *(note 3)*	2,199
Property (dispositions) *(note 3)*	(217)
Exploration and evaluation expense	(4,020)
Capitalized G&A and share-based compensation	936
Transfers to property, plant and equipment *(note 5)*	(1,386)
Balance, September 30, 2015	**92,211**

Exploration and evaluation assets consist of Petrus' undeveloped land and exploration and development projects which are pending the determination of technical feasibility. Additions represent the Company's share of costs incurred on these assets during the period. Exploration and evaluation assets are not subject to depletion. For the three and nine month periods ended September 30, 2015 the Company incurred exploration and evaluation expense in the Statement of Net Income (Loss) and Comprehensive Income (Loss) of $0.8 million and $4.0 million, respectively which relates to expiring undeveloped land in minor properties (three and nine months ended September 30, 2014; $0.1 million and $0.1 million, respectively).

During the three and nine months ended September 30, 2015 the Company capitalized $0.3 million and $0.9 million, respectively, of general & administrative expenses ("G&A") directly attributable to exploration activities (three and nine months ended September 30, 2014 - $0.4 million and $1.1 million). Included in this amount is non-cash share-based compensation for the three and nine months ended September 30, 2015 of $0.01 million and $0.2 million, respectively (three and nine months ended September 30, 2014 $0.1 million and $0.3 million, respectively).

5. PROPERTY, PLANT AND EQUIPMENT

$000s	Cost	Accumulated DD&A	Net book value
Balance, December 31, 2013	**175,891**	**(25,678)**	**150,213**
Additions	107,662	—	107,662
Property acquisitions	17,675	—	17,675
Property (dispositions)	(2,880)	816	(2,064)
Corporate acquisitions	317,935	—	317,935
Capitalized G&A and share-based compensation	1,272	—	1,272
Transfers from exploration and evaluation assets	147	—	147
Depletion & depreciation	—	(36,850)	(36,850)
Increase in decommissioning provision	43,492	—	43,492
Impairment loss	—	(104,762)	(104,762)
Balance, December 31, 2014	**661,194**	**(166,474)**	**494,720**
Additions	45,570	—	45,570
Property acquisitions *(note 3)*	6,512	—	6,512
Property (dispositions) *(note 3)*	(10,781)	3,173	(7,608)
Capitalized G&A and share-based compensation	936	—	936
Transfers from exploration and evaluation assets *(note 4)*	1,386	—	1,386
Depletion & depreciation	—	(42,360)	(42,360)
Increase in decommissioning provision *(note 7)*	4,422	—	4,422
Impairment loss	—	(28,541)	(28,541)
Balance, September 30, 2015	**709,239**	**(234,202)**	**475,037**

Estimated future development costs of $238.6 million (December 31, 2014 - $199.6 million) associated with the development of the Company's proved plus probable undeveloped reserves were included with the costs subject to depletion. During the three and nine month periods ended September 30, 2015 the Company capitalized $0.3 million and $0.9 million, respectively (three and nine months periods ended September 30, 2014 $0.4 million and $1.1 million, respectively) of general & administrative expenses ("G&A") directly attributable to development activities. Included in this amount is non-cash share-based compensation for the three and nine months ended September 30, 2015 of $0.01 million and $0.2 million, respectively (three and nine months ended September 30, 2014 $0.01 million and $0.3 million, respectively).

At September 30, 2015, due to a decrease in forward commodity prices and recent transaction metrics, the Company determined that indicators of impairment exist and therefore, an impairment test was performed for all of the Company's CGUs. The recoverable value of the Company's CGU's was estimated as the fair value less costs to sell based on the net present value of before tax cash flows from crude oil and natural gas proved plus probable reserves originally estimated by third party reserve evaluators and internally updated for production since December 31, 2014 plus an internal estimate of incremental development drilling locations and a discount rate of 12%. The Company recorded property, plant and equipment impairments of $28.5 million on two of its four CGUs (Peace River - $8.8 million; and Foothills - $19.7 million). The recoverable amount for the two CGUs was as follows: Peace River - $47.5 million; and Foothills - $108.4 million.

In calculating the net present values of cash flows from oil and natural gas reserves, the Company used a pre-tax discount rate of 12% and the following forward commodity price estimates:

	Foreign Exchange Rate	Oil (CDN$/bbl)[(1)]	AECO Gas (CDN$/mcf)
2015 Rem.	0.760	60.53	2.92
2016	0.780	70.77	3.42
2017	0.850	81.18	3.91
2018	0.850	89.41	4.49
2019	0.850	90.75	4.79
2020	0.850	93.08	4.87
2021	0.850	94.48	4.96
2022	0.850	95.90	5.04
2023	0.850	97.34	5.13
2024	0.850	98.80	5.22
2025	0.850	100.28	5.31
Remainder	0.850	+1.5%/yr	1.5%/yr

(1) Source: Sproule Canadian price forecasts ($CDN/bbl) for Canadian Light Sweet Crude

As at September 30, 2015, a one percent change in pre-tax discount rate is estimated to change the impairment by approximately $6.4 million; a $1.00/Bbl change in the price of oil is estimated to change the impairment by approximately $2.8 million; and a $0.10/mcf change in the price of natural gas is estimated to change the impairment by approximately $3.4 million.

6. DEBT

(a) Bank Indebtedness

On May 31, 2015 the Company renewed its existing syndicated credit facility and structured a $200 million facility comprised of a $20 million operating facility, a $160 million syndicated term-out facility and a $20 million non-borrowing base facility, (altogether the "Revolving Credit Facility " or "RCF"). The term-out facility has a revolving period that ends July 29, 2016 at which time it will either be renewed or converted to a one-year term facility. The non-borrowing base facility requires the prior written consent of the lenders before amounts can be drawn by the Company; therefore, at September 30, 2015, the amount available under the RCF was $180 million (December 31, 2014 - $200 million). The RCF bears interest at Canadian bank prime, or at the Company's option, Canadian bankers' acceptances, plus applicable margin and stamping fee. The stamping fees range, depending on Petrus' debt to EBITDA ratio (which is: earnings before interest, taxes, depreciation and amortization as defined in the banking agreement), between 100 bps and 250 bps on Canadian bank prime borrowings and between 200 bps and 350 bps on Canadian dollar bankers' acceptances. The undrawn portion of the RCF is subject to a standby fee in the range of 50 bps to 87.50 bps.

At September 30, 2015, the Company had a $2.4 million letter of credit outstanding against the RCF (December 31, 2014; Nil) and had drawn $142.9 million against the RCF (December 31, 2014; $99.7 million). Included in the Company's bank indebtedness is $3.6 million of overdraft cash.

The amount of the RCF is subject to a borrowing base review performed on a semi-annual basis by the lender, based primarily on reserves and commodity prices estimated by the lenders as well as other factors. A decrease in the borrowing base could result in a reduction to the available credit under the RCF. Subsequent to the end of the third quarter the total borrowing base was reviewed and reduced to $160 million which is comprised of a $20 million operating facility and a $140 million syndicated term-out facility. The $20 million non-borrowing base development facility was terminated by the Company. The Company has provided collateral by way of a $600 million debenture over all of the present and after acquired property of the Company.

The RCF carries a financial covenant which limits the Company's ability to borrow amounts greater than the RCF limit as well as:

(a) a financial covenant of PV10 to Net Secured Debt Ratio being less than 1.25 to 1.00 whereby Net Secured Debt (as defined by the banking agreement) means all amounts owing under the Credit Facility and any other secured debt of Petrus on a consolidated basis, minus restricted cash and cash equivalents and "PV10" means the discounted net present value (at a discount rate of 10%) of Petrus' proved reserves, as adjusted for commodity swaps then in effect and
(b) certain financial covenants only when any indebtedness under the Term Loan (note 6b) remain outstanding which are:
    a. The Working Capital Ratio will not be less than 1.00 to 1.00;
    b. The Proved Asset Coverage Ratio will not be less than 1.25 to 1.00; and
    c. The PDP Asset Coverage Ratio will not be less than 1.00 to 1.00.

Under the agreement, for purposes of the Working Capital Ratio, current assets are the current assets under IFRS 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. Current liabilities are the current liabilities under IFRS, 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, including the term loan debt.

At September 30, 2015 the Company was in compliance with all covenants under the revolving credit facility.

(b) Long Term Debt

The Company has a $90 million second lien term loan facility (the "Term Loan") which matures and is repayable on October 1, 2016. Interest is due and payable monthly and accrues at a per annum rate of (three-month) the Canadian Dealer offered Rate (CDOR) plus 700 basis points. The Term Loan is subject to three financial covenants: (1) the same financial covenant of PV10 to Net Secured Debt Ratio being not less than 1.25 to 1.00 as the Revolving Credit Facility (note 6a); (2) a covenant that Petrus may not, as of the effective date of each annual independent engineering reserve report and each internally prepared semi-annual internally prepared reserve report, permit the PDP to Net Secured Debt Ratio to be less than 1.00 to 1.00 where "PDP" means the present value (discounted at 10.0%) of future net revenues attributable to Petrus' PDP reserves and (3) Petrus' working capital ratio (current assets to current liabilities will not be less than 1.0 to 1.0.

Under the agreement, current assets are the current assets under IFRS plus any undrawn availability under the Revolving Credit Facility, 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. Current liabilities are the current liabilities under IFRS, 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, including the term loan debt.

The Term Loan is secured with a $250 million second lien priority interest on the same collateral as the Credit Facilities and requires a certain level of production volume to be hedged in 2015 and 2016. At September 30, 2015 the Company was in compliance with all covenants of the Term Loan.

7. DECOMMISSIONING OBLIGATION

The decommissioning liability was estimated based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The estimated future cash flows have been discounted using an average risk free rate of 1.97 percent and an inflation rate of 2 percent (December 31, 2014; 2.33 percent and 2 percent, respectively). Changes in estimates in 2015 are due to the decrease in discount rate from 2.33 percent at December 31, 2014 to 1.97 percent at September 30, 2015 (change in estimates in 2014 due to the decrease in discount rate from 3 percent to 2.33 percent and changes in estimated well life). The Company has estimated the net present value of the decommissioning obligations to be $63.4 million as at September 30, 2015 ($58.6 million at December 31, 2014). The undiscounted, uninflated total future liability at September 30, 2015 is $60.9 million ($61.8 million at December 31, 2014). The payments are expected to be incurred over the operating lives of the assets. The following table reconciles the decommissioning liability:

Balance, December 31, 2013	**15,547**
Property acquisitions	7,086
Corporate acquisitions	22,498
Liabilities incurred	7,009
Liabilities settled	(1,096)
Change in estimates	6,899
Accretion expense	691
Balance, December 31, 2014	**58,634**
Property acquisitions (note 3)	723
Property dispositions (note 3)	(517)
Liabilities incurred	509
Liabilities settled	(571)
Change in estimates	3,707
Accretion expense	907
Balance, September 30, 2015	**63,392**

8. FINANCIAL RISK MANAGEMENT

The Company utilizes commodity contracts as a risk management technique to mitigate exposure to commodity price volatility. The following table summarizes the financial derivative contracts Petrus has outstanding as at September 30, 2015:

Natural Gas Contract Period	Type	Daily Volume	Price (CAD$/GJ)
Oct. 1, 2015 to Oct. 31, 2015	Fixed price	3,000 GJ	$3.35/GJ
Oct. 1, 2015 to Oct. 31, 2015	Fixed price	2,000 GJ	$2.52/GJ
Oct. 1, 2015 to Oct. 31, 2015	Fixed price	6,000 GJ	$2.37/GJ
Oct. 1, 2015 to Oct. 31, 2015	Fixed price	4,000 GJ	$2.46/GJ
Oct. 1, 2015 to Dec. 31, 2015	Fixed price	4,000 GJ	$3.49/GJ
Oct. 1, 2015 to Dec. 31, 2015	Costless Collar	5,000 GJ	$3.50 – 3.63/GJ
Oct. 1, 2015 to Dec. 31, 2015	Fixed price	1,000 GJ	$2.97/GJ
Nov. 1, 2015 to Mar. 31, 2016	Fixed price	6,000 GJ	$3.74/GJ
Nov. 1, 2015 to Mar. 31, 2016	Fixed price	6,000 GJ	$2.87/GJ
Nov. 1, 2015 to Mar. 31, 2016	Fixed price	4,000 GJ	$2.96/GJ
Nov. 1, 2015 to Mar. 31, 2016	Fixed price	2,000 GJ	$3.03/GJ
Jan. 1, 2016 to Mar. 31, 2016	Fixed price	5,000 GJ	$3.26/GJ
Apr. 1, 2016 to Oct. 31, 2016	Fixed price	2,000 GJ	$2.93/GJ
Apr. 1, 2016 to Oct. 31, 2016	Fixed price	6,000 GJ	$2.75/GJ
Apr. 1, 2016 to Oct. 31, 2016	Fixed price	2,000 GJ	$2.85/GJ
Apr. 1, 2016 to Oct. 31, 2016	Fixed price	5,000 GJ	$2.91/GJ
Apr. 1, 2016 to Oct. 31, 2016	Costless collar	5,000 GJ	$2.50 – 3.15/GJ
Nov. 1, 2016 to Mar. 31, 2017	Fixed price	2,000 GJ	$3.38/GJ
Nov. 1, 2016 to Mar. 31, 2017	Fixed price	2,000 GJ	$3.31/GJ
Nov. 1, 2016 to Mar. 31, 2017	Fixed price	6,000 GJ	$3.21/GJ
Nov. 1, 2016 to Mar. 31, 2017	Costless collar	5,000 GJ	$2.75 – 3.75/GJ
Apr.1, 2017 to Oct. 31, 2017	Fixed price	7,000 GJ	$2.84/GJ

Crude Oil Contract Period	Type	Daily Volume	Price ($/Bbl)
Oct. 1, 2015 to Dec. 31, 2015	Fixed price	200 Bbl	WTI $CAD100.00/Bbl
Oct. 1, 2015 to Dec. 31,2015	Fixed Price	100 Bbl	WTI $CAD 95.50/Bbl
Oct. 1, 2015 to Dec. 31, 2015	Fixed Price	250 Bbl	WTI $97.80/Bbl
Oct. 1, 2015 to Dec. 31, 2015	Fixed Price	250 Bbl	WTI $92.50-103.50/Bbl
Oct. 1, 2015 to Dec. 31, 2015	Costless collar	700 Bbl	WTI $CAD39.00-70.00/Bbl
Oct. 1, 2015 to Dec. 31, 2015	Costless collar	500 Bbl	WTI $USD40.05-70.00/Bbl
Oct. 1, 2015 to Dec. 31, 2015	Costless collar	250 Bbl	WTI $USD40.00-71.00/Bbl
Jan. 1, 2016 to Mar. 31, 2016	Costless collar	250 Bbl	WTI $USD40.00-75.00/Bbl
Jan. 1, 2016 to Jun. 30, 2016	Fixed Price	250 Bbl	WTI $CAD77.70/Bbl
Jan. 1, 2016 to Jun. 30, 2016	Costless collar	250 Bbl	WTI $CAD70.00-83.40/Bbl
Jan. 1, 2016 to Dec. 31, 2016	Costless collar	250 Bbl	WTI $CAD70.00-82.30/Bbl
Jan. 1, 2016 to Dec. 31, 2016	Costless collar	700 Bbl	WTI $CAD70.00-75.75/Bbl
Jul. 1, 2016 to Sep. 30, 2016	Costless collar	250 Bbl	WTI $CAD70.00-84.00/Bbl
Oct. 1, 2016 to Dec. 31, 2016	Costless collar	250 Bbl	WTI $CAD70.00-85.00/Bbl
Jan. 1, 2017 to Mar. 31, 2017	Costless collar	500 Bbl	WTI $CAD70.00-78.00/Bbl
Jan. 1, 2017 to Jun. 30, 2017	Costless collar	500 Bbl	WTI $CAD70.00-78.40/Bbl

Electric Power Contract Period	Type	Annual Volume	Price (CAD)
Oct. 1, 2015 to Dec. 31, 2015	Fixed price	12,264 MW	$50.00/MWH

Risk Management Asset and Liability

$000s At December 31, 2014	Current Asset	Current Liability
Commodity derivatives	14,609	197
	14,609	**197**

At September 30, 2015	Current Asset	Current Liability
Commodity derivatives	10,763	192
	10,763	**192**

Earnings Impact of Realized and Unrealized Gains (Losses) on Commodity Financial Instruments

($)	Three months ended Sept. 30, 2015	Three months ended Sept. 30, 2014	Nine months ended Sept. 30, 2015	Nine months ended Sept. 30, 2014
Realized gain (loss)	3,767	(1,359)	11,543	(4,288)
Unrealized gain (loss)	5,205	5,370	(3,842)	2,105
	8,972	**4,011**	**7,701**	**(2,183)**

9. SHARE CAPITAL

Authorized

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

Issued and Outstanding

Common shares $000s *except share amounts*	Number of Shares	Amount
Balance, December 31, 2013	**86,376,598**	**144,339**
Common shares issued under private placement (a)	15,256,000	49,582
Flow-through shares issued, net of premium (a)	115,000	374
Common shares issued under private placement (b)	17,784,724	71,139
Flow-through shares issued, net of premium (b)	200,000	800
Common shares issued under private placement (c)	20,725,276	82,901
Common shares issued under private placement (d)	135,000	540
Share issue costs	—	(4,759)
Tax effect of share issue costs	—	1,190
Balance, December 31, 2014 & September 30, 2015	**140,592,598**	**346,106**

Share Issuances

(a) On June 2, 2014 the Company issued 15,256,000 common shares at a price of $3.25 per share and 115,000 flow-through shares at a price of $3.90 per share for total gross proceeds of $50.0 million. Of the issuance price, $0.65 per share or $0.1 million was determined to be the premium on the flow-through shares. The common shares issued were subject to a restricted hold period which expired on October 3, 2014.

(b) On September 5, 2014 the Company issued 17,784,724 common shares at a price of $4.00 per share and 200,000 flow-through shares at a price of $4.80 per share for total gross proceeds of $72.1 million. Of the issuance price, $0.80 per share or $0.2 million was determined to be the premium on the flow-through shares. The common shares issued are subject to a restricted hold period which expired on January 6, 2015.

(c) On September 23, 2014 the Company issued 20,725,276 common shares at a price of $4.00 per share for total gross proceeds of $82.9 million. The common shares issued are subject to a restricted hold period which expired on January 24, 2015.

(d) On October 15, 2014 the Company issued 135,000 common shares at a price of $4.00 per share for total gross proceeds of $0.5 million. The common shares issued are subject to a restricted hold period which expired on February 15, 2015.

SHARE-BASED COMPENSATION

Performance Warrants

The Company has issued performance warrants to employees, consultants and directors of the Company. 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 warrants expire five years from the date of issuance. Upon exercise of the warrants the Company may settle the obligation by issuing common shares of the Company. The shares to be offered consist of common shares of the Company`s authorized but unissued common shares. The aggregate number of shares issuable upon the exercise of all warrants granted shall not exceed 20% of the 32,113,016 issued and outstanding shares as at April 30, 2012. At September 30, 2015, 6,274,270 (December 31, 2014; 6,407,603) performance warrants were issued and outstanding.

	Number of warrants outstanding	Weighted Average Exercise Price ($)
Balance, December 31, 2013	**6,422,603**	**$2.02**
Forfeited or expired	(15,000)	$2.00
Balance, December 31, 2014	**6,407,603**	**$2.02**
Forfeited or expired	(133,333)	$2.00
Balance, September 30, 2015	**6,274,270**	**$2.02**
Exercisable, September 30, 2015	**3,799,564**	**$2.01**

The following tables summarize information about the performance warrants granted since inception:

Range of Exercise Price	Warrants Outstanding			Warrants Exercisable		
	Number granted	Weighted average exercise price	Weighted average remaining life (years)	Number exercisable	Weighted average exercise price	Weighted average remaining life (years)
\$2.00 - \$2.25	6,274,270	\$2.02	2.09	3,799,564	\$2.01	2.03
	6,274,270	**\$2.02**	**2.09**	**3,799,564**	**\$2.01**	**2.03**

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 plan 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. The options vest based on time (one third vest per year starting on the date of grant) and expire five years from the date of issuance. At September 30, 2015, 6,293,333 (December 31, 2014; 6,115,000) stock options were outstanding. The summary of stock option activity is presented below:

	Number of stock options	Weighted Average Exercise Price (\$)
Balance, December 31, 2013	**4,355,000**	**\$1.84**
Granted	1,805,000	\$3.18
Forfeited or expired	(45,000)	\$1.75
Balance, December 31, 2014	**6,115,000**	**\$2.21**
Granted	505,000	\$3.50
Forfeited or expired	(411,667)	\$2.34
Balance, September 30, 2015	**6,208,333**	**\$2.29**
Exercisable, September 30, 2015	**4,480,333**	**\$1.92**

The following tables summarize information about the stock options granted since inception:

Range of Exercise Price	Stock Options Outstanding			Stock Options Exercisable		
	Number granted	Weighted average exercise price	Weighted average remaining life (years)	Number exercisable	Weighted average exercise price	Weighted average remaining life (years)
\$1.75 - \$2.00	3,875,000	\$1.75	1.72	3,787,000	\$1.75	1.74
\$2.01 - \$2.75	741,667	\$2.40	3.34	322,000	\$2.37	3.34
\$2.76 - \$4.00	1,591,666	\$3.50	4.00	343,333	\$3.41	3.80
	6,208,333	**\$2.29**	**2.51**	**4,452,333**	**\$1.92**	**2.02**

The weighted average fair value of each stock option granted of \$1.24 for the nine months ended September 30, 2015 (year ended December 31, 2014 - \$1.12 per option) is estimated on the date of grant using the Black-Scholes pricing model with the following weighted average assumptions:

	Nine months ended September 30, 2015	Twelve months ended December 31, 2014
Risk free interest rate	1.40%	1.20% - 1.40%
Expected life (years)	5	5
Estimated volatility of underlying common shares (%)	50%	50%
Estimated forfeiture rate	20%	20%
Expected dividend yield (%)	0%	0%

Petrus estimated the volatility of the underlying common shares by analyzing the volatility of peer group private companies with similar corporate structure, oil and gas assets and size.

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

Share-based compensation costs ($):	Three months ended Sept. 30, 2015	Three months ended Sept. 30, 2014	Nine months ended Sept. 30, 2015	Nine months ended Sept. 30, 2014
Expensed in net income	87	189	581	512
Capitalized to exploration and evaluation assets	12	95	178	256
Capitalized to property, plant and equipment	13	95	177	256
Total share-based compensation	**112**	**379**	**936**	**1,024**

10. EARNINGS PER SHARE

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

	Three months ended Sept. 30, 2015	Three months ended Sept. 30, 2014	Nine months ended Sept. 30, 2015	Nine months ended Sept. 30, 2014
Net income (loss) for the period	**(20,503)**	**7,530**	**(32,166)**	**15,817**
Weighted average number of common shares – basic	**140,593**	108,212	**140,593**	95,312
Weighted average number of common shares - diluted	**140,593**	113,072	**140,593**	100,172
Net income (loss) per common share – basic	**(0.15)**	**0.07**	**(0.23)**	**0.17**
Net income (loss) per common share – diluted	**(0.15)**	**0.07**	**(0.23)**	**0.16**

In computing diluted earnings per share for the three and nine months ended September 30, 2015, all warrants and stock options were considered however no instruments were added to the calculation as their impact is anti-dilutive. In computing diluted earnings per share for the three and nine months ended September 30, 2014, 768,027 warrants and 2,068,846 stock options were added to the calculation as their impact is dilutive.

11. OPERATING EXPENSES

The Company's gross operating expenses for the three and nine months ending September 30, 2015 were $7.0 million and $25.4 million, respectively (September 30, 2014; $4.7 million and $12.8 million). For the three and nine months ended September 30, 2015, this includes $1.8 million and $5.6 million of processing, gathering and compression charges, respectively (September 30, 2014; $1.4 million and $4.1 million).

The Company generated processing income recoveries of $0.7 million and $1.7 million for the three and nine months ending September 30, 2015 respectively (September 30, 2014; $0.3 million and $0.5 million) which reduced the Company's reported operating expenses to $6.3 million and $23.7 million for the three and nine months ending September 30, 2015 (September 30, 2014; $4.4 million and $12.3 million).

12. GENERAL AND ADMINISTRATIVE EXPENSES

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

$000s	Three months ended Sept. 30, 2015	Three months ended Sept. 30, 2014	Nine months ended Sept. 30, 2015	Nine months ended Sept. 30, 2014
Salaries and benefits	1,452	808	3,681	2,500
Subscriptions and licenses	39	—	202	—
Office costs	645	905	1,840	1,367
Legal, accounting and consulting	108	379	974	784
Capitalized general and administrative	(570)	(646)	(1,516)	(1,775)
	1,674	**1,446**	**5,181**	**2,876**

13. FINANCIAL INSTRUMENTS

Risks associated with Financial Instruments

Credit risk

The Company may be exposed to certain losses in the event that counterparties to financial instruments fail to meet their obligations in accordance with agreed terms. The Company mitigates this risk by entering into transactions with highly rated major financial institutions and by routinely assessing the financial strength of its customers.

At September 30, 2015, financial assets on the balance sheet are comprised of cash, deposits, risk management assets and accounts receivable. The maximum credit risk associated with these financial instruments is the total carrying value.

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. The Company has not identified any significant concentration of credit risk. As at September 30, 2015 and December 31, 2014, the majority of Petrus' accounts receivable were all aged less than 90 days and the Company had no material past due (>120 days) receivables.

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, bank indebtedness, risk management liabilities and accrued liabilities. Management is currently considering a number of options, including financings, asset sales and an extension of the term loan, to ensure it has sufficient capital to meet its short and medium term commitments and objectives.

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.

At September 30, 2015 the Company had a $200 million credit facility, of which $34.6 million was available without further lender consent (December 31, 2014, the Company had a $200 million credit facility of which $100 million was available). Subsequent to September 30, 2015 the borrowing base was re-determined in conjunction with the October 31, 2015 semi-annual review and was reduced to $160 million (comprised of a $20 million operating facility and a $140 million syndicated term-out facility). The Company is exposed to the risk of reductions to its borrowing base for purposes of the revolving credit facility or term loan. At September 30, 2015 the Company does not have any material drilling or capital spending commitments.

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 and accounts receivable are not exposed to significant interest rate risk. The revolving credit facility is exposed to interest rate cash flow risk as it is 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% change in the Canadian prime interest rate in the three and nine months ended September 30, 2015 would have changed income by approximately $0.6 million and $1.6 million, respectively, which relates to interest expense on the average outstanding revolving credit facility during the period, assuming that all other variables remain constant (three and nine months ended September 30, 2014; $0.5 million and $0.6 million, respectively).

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.

For the three and nine months ended September 30, 2015, it is estimated that a $0.25/mcf change in the price of natural gas would have changed net income by $0.7 million and $2.2 million, respectively (three and nine months ended September 30, 2014; $0.4 million and $1.1 million, respectively). For the three and nine months ended September 30, 2015, it is estimated that a $5.00/CDN WTI/bbl change in the price of oil would have changed net income by $1.2 million and $4.4 million, respectively (three and nine months ended September 30, 2014; $0.8 million and $2.7 million, respectively).

14. COMMITMENTS

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

$000s	Total	< 1 year	1– 5 years
Corporate office lease	3,096	710	2,386
Total commitments	**3,096**	**710**	**2,386**

15. SUBSEQUENT EVENTS

Financial Risk Management

Subsequent to September 30, 2015, the Company entered into the following financial derivative contracts:

Natural Gas Contract Period	Type	Daily Volume	Price (CAD$/GJ)
Jan.1, 2016 to Mar. 31, 2017	Fixed price	4,000 GJ	$2.54/GJ
Apr.1, 2017 to Oct. 31, 2017	Fixed price	5,000 GJ	$2.64/GJ
Nov.1, 2017 to Mar. 31, 2018	Fixed price	5,000 GJ	$3.02/GJ

Crude Oil Contract Period	Type	Daily Volume	Price ($/Bbl)
Jan. 1, 2017 to Mar. 31, 2017	Costless collar	100 Bbl	WTI $CAD65.00-71.00/Bbl
Apr. 1, 2017 to Jun. 30, 2017	Costless collar	400 Bbl	WTI $CAD65.00-72.70/Bbl
Jul. 1, 2017 to Sep. 30, 2017	Costless collar	500 Bbl	WTI $CAD65.00-74.20/Bbl
Oct. 1, 2017 to Dec. 31, 2017	Costless collar	400 Bbl	WTI $CAD65.00-75.85/Bbl

Credit Facility

Subsequent to September 30, 2015 Petrus was subject to a semi-annual review of its revolving credit facility. The $180 million revolving credit facility was reduced to $160 million as a result of the reduced outlook in forward commodity pricing. The $20 million development tranche was voluntarily terminated by Petrus to reduce associated standby fees.

CORPORATE INFORMATION

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Neil Korchinski, P. Eng.
Vice President, Engineering and
Chief Operating Officer

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

Peter Verburg
Corporate Secretary

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Chairman
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Kevin L. Adair
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Peter Verburg
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AUDITOR
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Chartered Accountants
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