Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three Months and Year Ended December 31, 2016

Dated: March 30, 2017

Advisories

In this management's discussion and analysis ("MD&A"), unless otherwise indicated or the context otherwise requires, the terms "we", "us", "our", "PPR", "Prairie Provident" and "the Company": (i) when used in reference to periods prior to September 12, 2016, refer to Lone Pine Resources Inc. ("Lone Pine Resources") and Lone Pine Resources Canada Ltd. ("LPR Canada", now Prairie Provident Resources Canada Ltd., collectively, "Lone Pine"); and (ii) when used in reference to the period following September 12, 2016, refers to Prairie Provident Resources Inc., as parent corporation, together with its wholly-owned subsidiaries, Prairie Provident Resources Canada Ltd. (formerly Lone Pine Resources Canada Ltd.), Lone Pine Resources Inc. and Arsenal Energy Inc. This MD&A presents the results for the historical Lone Pine properties for the period up to September 12, 2016 and for the combination of Lone Pine and Arsenal Energy Inc. after September 12, 2016. See "Arrangement Agreement" section for details.

The following MD&A of PPR provides management's analysis of the Company's results of operations, financial position and outlook as at and for the three months and year ended December 31, 2016. This MD&A is dated March 30, 2017 and should be read in conjunction with the audited combined and consolidated financial statements of PPR as at and for the year ended December 31, 2016 (the "2016 Annual Financial Statements"). Additional information relating to PPR, including the Company's December 31, 2016 Annual Information Form, is available on SEDAR at www.sedar.com.

All financial information has been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (IASB).

Unless otherwise noted, all financial information provided herein is reported in Canadian dollars. Production volumes are presented on a working-interest basis, before royalties.

This MD&A contains forward-looking statements and non-IFRS measures. Readers are cautioned that the MD&A should be read in conjunction with the Company's disclosures under the headings "Forward-Looking Statements" and "Non-IFRS Measures" included at the end of this MD&A.

Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousands of barrels of oil equivalent
mmboe	millions of barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
mmbtu	million British Thermal Units
GJ	gigajoule
AECO	AECO "C" hub price index for Alberta natural gas
CGU	cash-generating-unit
DD&A	depreciation, depletion and amortization
E&E	exploration and evaluation
GAAP	generally accepted accounting principles
G&A	general and administrative
IFRS	International Financial Reporting Standards
P&D	production and development
RSU	restricted share unit
WTI	West Texas Intermediate

Financial and Operational Highlights

	Three Months Ended December 31,		Year Ended December 31,	
($000s except per unit amounts)	**2016**	2015	**2016**	2015
Financial				
Oil and natural gas revenue	**17,060**	8,783	**42,748**	39,335
Net loss	**(8,782)**	(15,390)	**(60,396)**	(59,894)
Per share – basic & diluted[1]	**(0.09)**	(0.16)	**(0.62)**	(0.61)
Adjusted Funds from operations[2]	**7,107**	7,007	**13,259**	26,382
Per share – basic & diluted[3]	**0.07**	0.07	**0.14**	0.27
Net capital expenditures	**11,918**	9,809	**34,875**	24,627
Production Volumes				
Crude oil (bbls/d)	**2,653**	1,799	**2,012**	1,820
Natural gas (Mcf/d)	**12,300**	4,130	**9,253**	4,577
Natural gas liquids (bbls/d)	**142**	63	**126**	69
Total (boe/d)	**4,845**	2,550	**3,680**	2,652
% Liquids	**58%**	73%	**58%**	71%
Average Realized Prices				
Crude oil ($/bbl)	**54.28**	46.58	**46.75**	51.24
Natural gas ($/Mcf)	**3.09**	2.56	**2.21**	3.01
Natural gas liquids ($/bbl)	**24.49**	17.08	**17.91**	10.76
Total ($/boe)	**38.27**	37.44	**31.74**	40.64
Operating Netback ($/boe)[4]				
Realized price	**38.27**	37.44	**31.74**	40.64
Royalties	**(5.09)**	(3.18)	**(3.63)**	(2.26)
Operating costs	**(13.92)**	(15.92)	**(17.39)**	(16.49)
Operating netback	**19.26**	18.34	**10.72**	21.89
Realized gains on derivative instruments	**3.06**	20.97	**7.23**	17.34
Operating netback, after realized gains on derivative instruments	**22.32**	39.31	**17.95**	39.23

2016 corporate developments:

- On September 12, 2016, Lone Pine and Arsenal Energy Inc. ("Arsenal") completed a business combination by way of a plan of arrangement (the "Arrangement") whereby the Arrangement brought together Lone Pine and Arsenal under a new parent corporation, PPR, of which Lone Pine and Arsenal became direct or indirect wholly-owned subsidiaries. PPR's shares were listed on the Toronto Stock Exchange under the symbol "PPR" on September 16, 2016. Following the Arrangement, former Lone Pine securityholders held approximately 77% of the fully diluted PPR shares, while former Arsenal securityholders held approximately 23%.

- In conjunction with the closing of the Arrangement on September 12, 2016, PPR renewed and amended its credit facility with a syndicate of lenders which provided a borrowing capacity of $55 million including a $45 million syndicated revolving credit facility and a $10 million operating facility (collectively, the "Amended Credit

1,3 As the historical financial statements were prepared on a combined and consolidated basis, it is not possible to measure per share amounts until subsequent to the closing of the Arrangement on September 12, 2016 when Lone Pine and Arsenal were brought under a common parent entity. The Company calculated per share information for the current and historical periods by assuming that the common shares issued upon the closing of the Arrangement at September 12, 2016 were outstanding since the beginning of the period.

2,4 Adjusted funds from operations and Operating Netback are non-IFRS measures and are defined below under "Other Advisories".

Facility") with no changes in interest margins from the previous agreement. The credit facility was subsequently amended on March 22, 2017 pursuant to the purchase of assets in the Greater Red Earth area (see Subsequent Events below for additional details) to provide a total borrowing capacity of $65 million.

- On December 16, 2016, the Company issued 5,465,000 flow-through common shares with respect to Canadian Exploration Expenses ("CEE") at $0.85 per share and 375,000 flow-through common shares with respect to Canadian Development Expenses ("CDE") at $0.80 per common share for total gross proceeds of $4.9 million.

- On February 13, 2017, PPR entered into an agreement to acquire oil and natural gas assets in the Greater Red Earth Area of Northern Alberta for cash consideration of $41 million (the "Red Earth Acquisition"). The acquisition closed on March 22, 2017. The assets acquired include high quality and low decline oil production which is complementary to PPR's existing operations at Evi in the Peace River Arch area of Northern Alberta. The acquisition further enhances the Company's size and competitive position through an increased liquids ratio, lower corporate decline and increased netbacks.

2016 highlights include:

- Annual production averaged 3,680 boe/day (58% liquids), a 39% increase compared to 2015 due to production additions from the 2015 and 2016 Wheatland drilling program, with 15 wells commencing production throughout 2016, resulting in an incremental annual production of approximately 1,230 boe/d. Additionally, 2016 results include production from Arsenal's properties since September 12, 2016, resulting in increases in 2016 production by approximately 400 boe/d. Production additions were partially offset by natural declines. The Company exited 2016 with production of approximately 5,500 boe/d. Subsequent to December 31, 2016, 2 additional Wheatland wells have been brought on production and the Red Earth Acquisition was completed. Taking these events as well as natural production declines into account, current estimated production is approximately 6,500 boe/d.

- At Wheatland, PPR has been focusing on its 2016 14-well drilling program, which increased the gross well counts in the area to 18 with 100% success rate. In the first three quarters of 2016, 11 wells were drilled of which 4 were brought on-stream. During the fourth quarter of 2016, 3 additional gross wells were drilled and completed and 8 wells were brought on-stream. The remaining 2 wells drilled and completed in Q4 2016 that were not on production by the end of the year were brought on-stream in February 2017.

- Operating netback after realized hedging gains was $17.95/boe for 2016, a decrease of $21.28/boe from 2015. The decrease was primarily due to lower realized gains on derivative instruments and lower realized prices.

- Adjusted funds from operations were $13.3 million, a $13.1 million decrease as compared to 2015 adjusted funds from operations of $26.4 million primarily due to lower operating netback after realized gains on derivative instruments, partially offset by higher production and lower G&A expenses.

- Capital expenditures for the year were $34.9 million including $31.2 million on the Wheatland drilling program and $2.3 million on the second phase of the Evi Waterflood project.

- Impairment losses of $26.7 million included $25.0 million related to E&E assets in the Quebec exploratory area, $0.9 million related to the write down of certain leases that are due to expire within the next twelve months and $0.8 million related to changes in estimated decommissioning liabilities for assets with a carrying value of nil.

- Net loss was $60.4 million, compared to a net loss of $59.9 million in 2015. The $0.5 million increase in net loss was a result of $13.1 decrease in adjusted funds from operations, $2.3 million increase in transaction costs, offset by $1.0 million decrease in reorganization costs and $13.9 million of positive variances from various non-cash items. Transaction costs were incurred in 2016 for the Arrangement, while reorganization activities in

2015 related primarily to staff reduction. Positive variances in non-cash items were primarily due to the recognition of $9.6 million of foreign exchange gains (2015 – $25.5 million loss) and $2.9 million decrease in accretion expense, partially offset by $13.4 million increase in impairment losses and $12.4 million increase in unrealized losses on derivative instruments. Both the non-cash accretion expense and the foreign exchange gains related primarily to the US dollar denominated preferred shares, which were converted to PPR common shares under the Arrangement.

- Exited the year with long-term debt of $15.0 million under the $55-million credit facility and a working capital deficit[1] of $4.4 million. Upon the close of the Red Earth Acquisition the Company had $49.0 million of borrowings drawn on its credit facility.

Fourth quarter highlights include:

- Production averaged 4,845 boe/day (58% liquids), a 90% increase compared to the fourth quarter of 2015 due to production additions from the 2015 and 2016 Wheatland drilling program, resulting in incremental production of approximately 1,650 boe/d in the fourth quarter of 2016. Additionally, production from Arsenal's properties since September 12, 2016 resulted in increases in fourth quarter 2016 production by approximately 1,300 boe/d. Production additions were partially offset by natural declines.

- Operating netback after realized hedging gains was $22.32/boe for the fourth quarter of 2016, a decrease of $16.99/boe from the fourth quarter of 2015. The decrease was primarily due to lower realized gains on derivative instruments.

- Adjusted funds from operations were $7.1 million, a $0.1 million decrease as compared to the fourth quarter of 2015. Lower operating netback after realized hedging was offset by higher production, resulting in marginal change in adjusted funds from operations between the two periods.

- Capital expenditures were $11.9 million, primarily spent on the Wheatland drilling program.

- PPR recognized $0.9 million of insurance recovery in the fourth quarter of 2016 for an insurance claim filed for a breach in an above-ground section of wellhead pipeline in the Wheatland area that occurred in January 2016.

- Net loss of $8.8 million, compared to a net loss of $15.4 million in the fourth quarter of 2015. The $6.6 million decrease in net loss was primarily due to positive variances in several non-cash items, including $7.9 million decrease in impairment loss, $3.6 million decrease in accretion expense and $5.4 million decrease in foreign exchange loss, partially offset by $6.5 million increase in unrealized loss on derivative instruments and $3.6 million increase in DD&A.

[1] Working capital deficit is a non-IFRS measure and is defined in Other Advisories.

Outlook

2016 Targets

- Achieved 2016 exit production of 5,500 boe/d, 10% over its guidance.
- Successfully delivered 14-well drilling program with 100% success rate with capital expenditures of $34.9 million, which was in line with guidance of $34.2 million ($37.3 million less $3.1 million for decommissioning expenses).
- Exceeded Q4 2016 adjusted funds from operations guidance by 42%.

2017 Targets

PPR updated its 2017 guidance to incorporate the impact from the Red Earth Acquisition. Given the complementary and synergistic nature of the acquired assets, PPR is maintaining its 2017 capital budget range of $25.0 million to $35.0 million (including $3.0 - $4.0 million on decommissioning activities). PPR remains focused on long-term value creation through the development of its core assets. The Company plans to maintain a prudent financial position by actively managing its capital program with careful consideration of the commodity pricing environment in order to optimize leverage, liquidity and cash flows.

The 2017 program assumes price forecast of USD$54.00/bbl WTI, CAD$2.75/GJ AECO, and a Canadian/US dollar exchange rate of $0.76 and anticipates the following:

	Targets
Exit production (boe/d)	7,500 – 8,000
Annual production (boe/d) [1]	6,100 – 6,600
% of liquids	60% - 65%
Operating expenses ($/boe)	16.00 – 17.00
Operating netback ($/boe) [2]	16.00 – 17.00
Operating netback, after realized gains from derivative instruments ($/boe)	17.00 – 18.00
Royalties (%)	16%
G&A, excluding stock-based compensation and net of capitalized G&A ($/boe)	3.00 – 4.00
Capital expenditures ($millions)	25 – 35

(1) Includes production from the Red Earth Acquisition since March 22, 2017, the closing date of the transaction.
(2) Operating netback is a non-IFRS measure (see "Other Advisories" below).

Arrangement Agreement

On September 12, 2016, Lone Pine and Arsenal completed a business combination by way of a plan of arrangement whereby Lone Pine and Arsenal became direct or indirect wholly-owned subsidiaries of Prairie Provident Resources Inc. Prior to the Arrangement, LPR Canada and Lone Pine Resources were under common control in accordance with IFRS. The Arrangement involved the following key steps:

- Issuance of 13.9 million PPR common shares to the shareholders of LPR Canada in exchange for all LPR Canada common shares;
- Issuance of 60.9 million PPR common shares in exchange for all LPR Canada preferred shares;
- Amalgamation of Lone Pine Resources with a wholly-owned subsidiary of PPR, whereby PPR became the sole owner of the amalgamated company. The outstanding Lone Pine Resources common shares were cancelled without any consideration; and
- The acquisition of all of the issued and outstanding common voting shares of Arsenal with 22.7 million PPR common shares pursuant to the Arrangement in accordance with the terms and conditions of the arrangement agreement dated June 23, 2016 as amended on August 2, 2016 (the “Business Combination”).

The exchange of PPR common shares for LPR Canada preferred shares and LPR Canada common shares, and the amalgamation of PPR's wholly owned-subsidiary with Lone Pine Resources were not considered business combinations as there was no change to the controlling shareholder group resulting from the transactions. Accordingly, the consolidated financial statements of Prairie Provident have been prepared as a continuation of LPR Canada and Lone Pine Resources' combined and consolidated financial statements. Subsequently, on November 1, 2016, LPR Canada changed its name to Prairie Provident Canada Resources Ltd.

The concurrent acquisition of Arsenal common shares has been accounted for as a business combination using the acquisition method of accounting whereby PPR is deemed to be the acquirer of the Arsenal business and the assets and liabilities assumed are recorded at their fair values. Transaction costs associated with the acquisition are expensed when incurred. Arsenal's operating results are included in the consolidated financial results of PPR since September 12, 2016, the closing date of the Business Combination.

On September 12, 2016, PPR elected, pursuant to the *Business Corporations Act*, to eliminate its contributed surplus, excluding the portion related to the outstanding long-term incentive awards, accumulated deficit and accumulated other comprehensive income against its share capital. The Company's share capital was reduced solely for accounting purposes, without payment or reduction to the Company's or its subsidiaries' stated capital or paid up capital. Accordingly, the accumulated deficit as at December 31, 2016 reflected the results of operations of PPR from September 12, 2016 to December 31, 2016.

Subsequent Events

On February 13, 2017, PPR entered into an agreement to acquire oil and natural gas assets in the Greater Red Earth area of Northern Alberta for cash consideration of $41 million, before closing adjustments. The acquisition closed on March 22, 2017. The assets acquired include high quality and low decline oil production which is complementary to PPR's existing operations at Evi in the Peach River Arch area of Northern Alberta and further enhances the Company's size and competitive position. The Greater Red Earth asset includes producing assets with current production of approximately 1,100 boe/d (98% liquids weighting) and approximately 78,000 net acres of undeveloped land. The acquisition was funded through the Company's credit facility, which was amended on March 22, 2017 and now has a total borrowing capacity of $65 million including a $55 million syndicated revolving credit facility and a $10 million operating facility, and through the proceeds from a bought deal financing of $8.0 million which closed on March 16, 2017. In conjunction with the amendment of the credit facility, the financial covenant for current assets to current liabilities has been rescinded for the first quarter of 2017. Upon the close of the Red Earth Acquisition the Company had $49.0 million of borrowings drawn on its credit facility.

Under the bought deal financing, the Company issued 5,195,000 flow-through common shares with respect to CEE at $0.77 per share and 5,971,000 subscription receipts ("Subscription Receipt") at $0.67 per share for gross proceeds of $8.0 million. The proceeds from the sale of Subscription Receipts were held in escrow until the closing of the Red Earth Acquisition, upon which, the purchasers of the Subscription Receipts automatically received, for every Subscription Receipt held, one PPR common share and one-half of one common share purchase warrant (each whole warrant, a "Warrant"). Each Warrant will entitle the holder to acquire one common share at an exercise price of $0.87 per share until March 16, 2019. The underwriters have an over-allotment option to purchase, in whole or in part, at any time prior to April 15, 2017, up to an additional 779,250 flow-through common shares and 895,650 common shares for total additional gross proceeds of up to approximately $1.2 million.

Results of Operations

Production

	Three Months Ended December 31,		Year Ended December 31,	
	2016	2015	**2016**	2015
Crude oil (bbls/d)	**2,653**	1,799	**2,012**	1,820
Natural gas (Mcf/d)	**12,300**	4,130	**9,253**	4,577
Natural gas liquids (bbls/d)	**142**	63	**126**	69
Total (boe/d)	**4,845**	2,550	**3,680**	2,652
Liquids Weighting	**58%**	73%	**58%**	71%

PPR's production for the three months and year ended December 31, 2016 increased by 90% and 39%, respectively, compared to the corresponding periods in 2015. The increases were primarily the result of added production from the 2015 and 2016 Wheatland drilling program and the Arsenal acquisition. As at December 31, 2016, 16 of the 18 wells drilled per the Wheatland drilling program were on production, resulting in an incremental production for the three months and year ended December 31, 2016 of approximately 1,650 boe/d and 1,230 boe/d, respectively. The two remaining wells were tied-in and brought on production in February 2017. Further contributing to the production increase were the Arsenal properties, which have been included in PPR's operating results since the closing date of the Arrangement on September 12, 2016. This resulted in an increase in production for the three months and year ended December 31, 2016 of approximately 1,300 boe/d and 400 boe/d respectively. Increases in production from the Wheatland drilling program and the Arrangement were partially offset by natural production declines and the shut-in of uneconomic wells since May 2015.

The decline in the liquids-weighting from the three months and year ended December 31, 2015 was primarily related to production in the Wheatland area, which has a lower liquids-weighting than the remaining assets.

Revenue

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per unit amounts)	**2016**	2015	**2016**	2015
Revenue				
Crude oil	**13,248**	7, 710	**34,428**	34,041
Natural gas	**3,492**	974	**7,494**	5,023
Natural gas liquids	**320**	99	**826**	271
Oil and natural gas revenue	**17,060**	8,783	**42,748**	39,335
Average Realized Prices				
Crude oil ($/bbl)	**54.28**	46.58	**46.75**	51.24
Natural gas ($/Mcf)	**3.09**	2.56	**2.21**	3.01
Natural gas liquids ($/bbl)	**24.49**	17.08	**17.91**	10.76
Total ($/boe)	**38.27**	37.44	**31.74**	40.64
Benchmark Prices				
Crude oil - WTI ($/bbl)	**65.78**	57.56	**57.38**	62.42
Crude oil - Edmonton Light Sweet ($/bbl)	**61.13**	52.21	**52.50**	56.51
Natural gas - AECO daily index - 5A ($/Mcf)	**3.05**	2.65	**2.15**	2.77
Exchange rate - US$/CDN$	**0.75**	0.75	**0.76**	0.78

Global crude oil prices strengthened in the fourth quarter of 2016 as OPEC members agreed to a production cut. PPR realized crude oil price is primarily referenced to Edmonton Light Sweet prices, which increased by 17% in the fourth quarter of 2016, compared to the same period in 2015. Fourth quarter 2016 AECO prices also increased by

15% due to tighter supply and demand gap caused by cold weather. Despite the strengthening of commodity prices for the fourth quarter of 2016, the increases were not sufficient to offset the depressed prices observed in the first half of 2016, resulting in year-over-year decreases of 7% and 23% in Edmonton Light Sweet prices and AECO prices.

PPR's fourth quarter 2016 revenue increased by 94% or $8.3 million from the fourth quarter of 2015. The 72% increase in crude oil revenue incorporates a 47% increase in oil production and a 17% rise in realized prices. The 259% increase in natural gas revenue was the result of a 198% increase in production and a 21% increase in realized prices. The movements in PPR's realized prices generally correlated with those observed in the benchmark prices. The overall average realized prices did not increase to the same extent as individual commodity prices due to a lower liquids-weighted production mix in 2016 than in 2015.

Annual 2016 revenue increased by 9% or $3.4 million as compared against the same period in 2015. The 1% increase in crude oil revenue and the 49% increase in natural gas revenue incorporated higher production, which rose by 11% and 102%, respectively, offset by decreases in realized prices of crude oil and natural gas of 9% and 27%, respectively. The lower realized prices reflected the declines in benchmark prices. The decrease in the overall average realized prices of 22% also incorporated a lower liquids-weighted production mix in 2016 than in 2015.

Royalties

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2016**	2015	**2016**	2015
Royalties	**2,270**	746	**4,893**	2,190
Per boe	**5.09**	3.18	**3.63**	2.26
Percentage of revenue	**13.3%**	8.5%	**11.4%**	5.6%

Crown royalties are based on various sliding scales that are dependent on incentives, production volumes and commodity prices. Production in the Wheatland area is subject to flat royalty rates of between 15% and 17.5%, which is currently higher than the average royalty rates of the remaining properties. On a percentage of revenue basis, royalties for the three months and year ended December 31, 2016 increased from the corresponding period in 2015 primarily as a result of higher Wheatland production.

Commodity Price and Risk Management

PPR enters into derivative risk management contracts to manage exposure to commodity price fluctuations and to protect and provide certainty on a portion of the Company's cash flows. PPR considers these derivative contracts to be an effective means to manage cash flows from operations.

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2016**	2015	**2016**	2015
Realized gain on derivatives	**1,362**	4,921	**9,743**	16,785
Unrealized loss on derivatives	**(7,231)**	(730)	**(19,274)**	(6,843)
Total gain (loss) on derivatives	**(5,869)**	4,191	**(9,531)**	9,942
Per boe				
Realized gain on derivatives	**3.06**	20.97	**7.23**	17.34
Unrealized loss on derivatives	**(16.22)**	(3.11)	**(14.31)**	(7.07)
Total gain (loss) on derivatives	**(13.17)**	17.86	**(7.08)**	10.27

Realized gains and losses on derivative risk management contracts represent the cash settlements of outstanding contracts while unrealized gains and losses on derivative risk management reflect changes in mark-to-market positions of outstanding contracts in the current period. Both realized and unrealized gains and losses on derivate contracts vary based on fluctuations related to the specific terms of outstanding contracts in the related period including contract types, contract quantities and fluctuations in underlying commodity reference prices.

When compared against the same period in 2015, realized gain for the fourth quarter of 2016 decreased by $3.6 million due to lower gains realized from oil commodity contracts as a result of lower contract prices and higher settlement prices. Unrealized loss for the fourth quarter of 2016 was $6.5 million higher than the same period in 2015. At December 31, 2016, a larger portion of PPR outstanding oil derivatives were costless collars which generated much lower fair value as the forward prices were within the floor and cap prices. Improvements in forward pricing as of December 31, 2016, as compared to December 31, 2015, further contributed to the increased marked-to-marked losses.

For the year ended December 31, 2016, the Company realized gains on derivatives were $7.0 million lower than the prior year, while unrealized loss on derivatives were $12.4 million higher. The variances were due to the same reasons as discussed above.

As of December 31, 2016, the Company held the following outstanding derivative contracts:

Commodity Contract	Notional Quantity	Remaining Term	Reference	Weighted Average Price		Contract Type
Oil	500bbls/d	January 1, 2017 – December 31, 2017	CDN$ WTI	$	65.00/72.00	Collar
Oil	250 bbls/d	January 1, 2017 – December 31, 2017	CDN$ WTI	$	65.00/75.00	Collar
Oil	500 bbls/d	January 1, 2017 – December 31, 2017	CDN$ WTI	$	58.00/67.50	Collar
Oil	500 bbls/d	January 1, 2017 – December 31, 2017	CDN$ WTI	$	87.78	Swap
Light Oil [1] Differential	1,000 bbls/d	January 1, 2017 – December 31, 2017	CDN$ MSW	$	-5.70	Swap
Natural Gas	1,800 GJ/d	January 1, 2017 – December 31, 2017	AECO 7A Monthly Index	$	2.60	Swap
Natural Gas	2,750 GJ/d	January 1, 2017 – December 31, 2017	AECO 7A Monthly Index	$	2.91	Swap
Oil	500 bbls/d	January 1, 2018 – December 31, 2018	USD$ WTI	$	65.00	Sold Call Option
Oil	800 bbls/d	January 1, 2018 – December 31, 2018	CDN$ WTI	$	58.00/ 67.50	Collar

(1) Settled on the monthly average Mixed Sweet Blend (“MSW”) Differential to WTI

All derivatives contracts were entered with PPR’s credit facility lenders to minimize the need to post any collateral.

Operating Expenses

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2016**	2015	**2016**	2015
Lease operating expense	**4,118**	2,943	**16,515**	12,924
Transportation and processing	**1,582**	319	**5,128**	1,147
Production and property taxes	**504**	472	**1,774**	1,888
Total operating expenses	**6,204**	3,734	**23,417**	15,959
Per boe	**13.92**	15.92	**17.39**	16.49

Lease operating expense for the fourth quarter and year of 2016 increased by 40% and 28%, respectively, from the same periods in 2015 primarily due to incremental production from Wheatland and the Arsenal assets. For the fourth quarter of 2016, the increased costs were offset by a $0.9 million insurance recovery that was received in the period related to a breach in an above-ground section of wellhead piping that occurred on January 22, 2016. The Company incurred $1.0 million of site clean-up and remediation costs which was recorded as lease operating expenses in the first quarter of 2016.

Transportation and processing expense for the three months and year ended December 31, 2016 increased by $1.2 million and $4.0 million, respectively, as compared to the same periods in 2015. The increase primarily related to third-party natural gas processing costs and natural gas transportation costs incurred on Wheatland production. Additionally, during 2015, the Company recognized certain positive cost recovery adjustments relating to prior production periods, which further contributed to the year-over-year increase.

Operating expenses on a per boe basis were lower in the fourth quarter of 2016 as compared to the same period in 2015 primarily as the result of the $0.9 million insurance recovery received in the fourth quarter of 2016. Excluding this recovery, operating costs on a per boe basis between 2016 and 2015 would be comparable. The 2016 operating costs were higher than 2015 operating costs on a per boe basis primarily as a result of positive cost recovery adjustments that were recorded in 2015.

Operating Netback

	Three Months Ended December 31,		Year Ended December 31,	
($ per boe)	**2016**	2015	**2016**	2015
Revenue	**38.27**	37.44	**31.74**	40.64
Royalties	**(5.09)**	(3.18)	**(3.63)**	(2.26)
Operating costs	**(13.92)**	(15.92)	**(17.39)**	(16.49)
Operating netback	**19.26**	18.34	**10.72**	21.89
Realized gains on derivative instruments	**3.06**	20.97	**7.23**	17.34
Operating netback, after realized gains on derivative instruments	**22.32**	39.31	**17.95**	39.23

PPR's operating netback after realized hedging gains decreased by $16.99/boe and $21.28/boe, respectively, for the three months and year ended December 31, 2016, compared to the corresponding periods in 2015. For the fourth quarter of 2016, decreases in realized gains on derivative instruments and increases in royalties were partially offset by increases in realized prices and decreases in operating costs. For the 2016 annual period, decreases in realized revenue were compounded by increases in operating costs and royalties, and decreases in realized gains on derivative instruments.

General and Administrative Expenses ("G&A")

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2016**	2015	**2016**	2015
Gross cash G&A expenses	**3,043**	2,432	**11,872**	12,188
Gross share-based compensation expense	**195**	206	**392**	1,073
Less amounts capitalized	**(500)**	(382)	**(1,434)**	(831)
Net G&A expenses	**2,738**	2,256	**10,830**	12,430
Per boe	**6.14**	9.62	**8.04**	12.84

For the three months ended December 31, 2016, gross cash G&A increased by $0.6 million compared to the same period in 2015. The increase primarily relates to the Arrangement with Arsenal which resulted in an increase in employee headcount. Gross cash G&A for the 2016 annual period decreased by $0.3 million from the 2015 annual period primarily related to cost reduction efforts, partially offset by increases in G&A as a result of the Arrangement with Arsenal. Changes in gross share-based compensation expense relate to the number of units granted, the timing of grants, the fair value of units on the grant date, and the vesting period over which the related expense is recognized. The Company expects gross cash G&A and gross share-based compensation expense to increase in

2017 as a result of the Arrangement with Arsenal and share-based incentive awards granted to employees, officers and directors in the fourth quarter of 2016 and the first quarter of 2017.

Capitalized G&A varies with the composition and compensation levels of technical departments. The increase in capitalized G&A for the three months and year ended December 31, 2016 compared to the same periods in 2015 relates to the staffing levels in the technical departments in the related periods. Minimal capitalized G&A was recognized in the first half of 2015 due to the suspension of capital activities during that period.

Share-based compensation

In conjunction with the closing of the Arrangement, the Company adopted new long-term incentive plans for employees and directors pursuant to which share-based incentive awards are granted.

The Company granted 752,174 stock options to employees, officers and directors at an exercise price of $0.96 per share upon completion of the Arrangement. Options granted vest in three tranches, on January 1, 2017 and on the second and third anniversaries thereafter, and will expire five years after the grant date. As at December 31, 2016, 752,174 stock options were outstanding, of which none was exercisable.

The Company also issued 116,427 performance share units ("PSUs") to certain officers of the Company upon the completion of the Arrangement. PSUs vest on December 15, 2018 and are subject to a multiplier from 0 to 2 based on share performance relative to a selected peer group. PSUs will be settled in common shares or cash at the discretion of the Company however, it is PPR's intention to settle the PSUs in common shares and the plan has accounted for as equity settled. As at December 31, 2016, 116,427 PSUs were outstanding.

Under the Company's prior equity incentive plan, the Company had issued restricted share units ("RSUs") in 2014. As at December 31, 2016, there was 142,812 RSUs outstanding which will vest on January 31, 2017.

Subsequent to December 31, 2016, the Company granted an additional 1,869,795 options with an exercise price of $0.76 per share and 354,905 PSUs.

Finance Costs

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2016**	2015	**2016**	2015
Interest expense	**230**	169	**730**	828
Accretion expenses	**451**	4,049	**12,389**	15,317
Total finance cost	**681**	4,218	**13,119**	16,145
Per boe	**1.53**	17.98	**9.74**	16.68

For the majority of 2016 annual period, there were no borrowings outstanding on the Company's credit facilities, with the Company started drawing on the facility in late September. Additionally, there were no borrowings on the credit facility during the three months and year ended December 31, 2015. The interest expense incurred in the periods without outstanding borrowings was primarily comprised of the amortization of deferred financing charges, recognition of standby fees and interest incurred on outstanding letters of credit. Interest expense increased by 36% in the three months ended December 31, 2016 compared to the three months ended December 31, 2015 primarily due to interest on outstanding borrowing. Interest expense decreased by 12% for the year ended December 31, 2016 from the same period in 2015 due to decreases in interest rates on standby fees and letter of credit fees upon amendment and renewal of the Company's credit facility on July 30, 2015 and decreased deferred financing fees partially offset by interest incurred on outstanding borrowings in the fourth quarter of 2016. The weighted average effective interest rate on credit facility borrowings and outstanding letters of credit for the three months and year ended December 31, 2016 was 2.6% and 2.3%, respectively. The weighted average effective interest rate on letters of credit outstanding for the three months and year ended December 31, 2015 was 2.0% and 2.3%, respectively.

Accretion charges are non-cash expenses. Historically, the Company's accretion expense was primarily comprised of accretion on preferred shares. Pursuant to the Arrangement, outstanding preferred shares were exchanged for PPR common shares and as such accretion expense on preferred shares is no longer recognized after September 12, 2016 (see Preferred Shares under the Capital Resources section below). During the fourth quarter of 2016 and the year of 2016, the Company recognized $nil and $11.0 million, respectively, of accretion charges on the preferred shares (2015 – $3.7 million and $14.0 million, respectively). The exchange of preferred shares for common shares will result in a material reduction of accretion expense in future periods. The remaining accretion charges primarily related to the decommissioning liabilities and increased in the fourth quarter of 2016 from the same period in the prior year as a result of additional decommissioning liabilities acquired from the acquisition of Arsenal.

Gain (Loss) on Foreign Exchange

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2016**	2015	**2016**	2015
Realized gain (loss) on foreign exchange	**(135)**	2	**(103)**	–
Unrealized gain (loss) on foreign exchange	**(80)**	5,285	**9,613**	25,498
Gain (loss) on foreign exchange	**(215)**	5,287	**9,510**	25,498

Foreign exchange gains (losses) incurred in the years ended December 31, 2016 and 2015 and the three months ended December 31, 2015 related mainly to the previously outstanding US dollar denominated preferred shares (see Preferred Shares under the Capital Resources section below). The weakening (strengthening) of the Canadian dollar during a period would result in unrealized foreign exchange loss (gain) on preferred shares. Pursuant to the Arrangement, outstanding preferred shares were exchanged for PPR common shares on September 12, 2016 and as such foreign exchange fluctuations of the US dollar had a significantly reduced impact in the fourth quarter of 2016.

Exploration and Evaluation Expense

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2016**	2015	**2016**	2015
Exploration and evaluation expense	**9**	379	**58**	545
Per boe	**0.02**	1.62	**0.04**	0.56

Depletion and Depreciation

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2016**	2015	**2016**	2015
Depletion and depreciation	**7,409**	3,789	**21,344**	21,436
Per boe	**16.62**	16.15	**15.85**	22.15

Depletion and depreciation rates are subject to change based on changes in the carrying value of the asset base, changes in future development costs, reserve updates and changes in production by area. The decrease in the per boe depletion and depreciation rate in the year ended December 31, 2016 from the comparable period in 2015 incorporated the decrease in future development costs in the Evi area as well as lower finding and development costs at the Wheatland area. The slight increase in the fourth quarter 2016 depletion rate from the fourth quarter 2015 depletion rates incorporates the Arsenal assets and related reserves.

Impairment Loss

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2016**	2015	**2016**	2015
E&E impairment	**—**	4,868	**25,872**	8,108
E&E impairment – decommissioning asset	**13**	2,410	**(5)**	2,410
Total E&E impairment	**13**	7,278	**25,867**	10,518
P&D impairment	**—**	—	**—**	912
P&D impairment – decommissioning asset	**(25)**	270	**823**	1,506
P&D inventory impairment	**—**	212	**200**	212
Total P&D impairment	**(25)**	482	**1,023**	2,630
Inventory impairment (recovery)	**(42)**	45	**(167)**	150
Total impairment loss	**(54)**	7,804	**26,723**	13,298

Fourth quarter 2016 E&E impairment relates to changes in estimated decommission liabilities of certain properties with carrying values of nil. Annual 2016 E&E impairment losses include included $25.0 million of impairment losses recognized in the second quarter of 2016 against assets in the Quebec exploratory area, as a result of a shift in management development priorities as a result of successful drilling in the Wheatland area, additional development prospects from the Arrangement with Arsenal, along with a prolonged period of political uncertainty around oil and gas development in the province of Quebec. In addition, year-to-date 2016 E&E included $0.9 million of impairment recognized relating to leases that were due to expire in the next twelve months in the Evi CGU.

Fourth quarter P&D impairment recovery of a nominal amount and year-to-date 2016 impairment of $0.8 million related to changes in estimated decommissioning liabilities of certain properties with a carrying value of nil. Year-to-date P&D impairment included P&D inventory impairment of $0.2 million incurred in the second quarter of 2016 for the write down of certain surplus equipment.

Fourth quarter impairment recovery included a nominal recovery for the increase in the net realizable value of oil inventory, while the 2016 annual impairment loss was offset by $0.2 million of impairment recoveries recorded as the result of an increase in the net realizable value of oil inventory.

Fourth quarter and year-to-date 2015 E&E impairment losses were incurred as a result of changes in management development plans due to significant and prolonged decreases in commodity prices. Additional impairment losses were recorded related to the changes in the current year's decommissioning liability estimates on certain E&E assets that were impaired in previous years.

The P&D impairment charges recognized in the fourth quarter and year-to-date 2015 primarily related to the change in the current year's decommissioning liability estimates on certain properties with no carrying value and on the write down of certain surplus inventory. Additionally, year-to-date P&D impairment charges incorporate $0.9 million related to the Provost (formerly Hayter) CGU as a result of continued declines in forward crude oil and natural gas prices.

Impairment charges could be reversed in future periods should commodity prices recover or should development plans change.

Adjusted Funds from Operations

Adjusted funds from operations increased to $7.1 million in the fourth quarter of 2016 from $7.0 million in the same period in 2015. Lower operating netback after realized hedging was offset by higher production, resulting in marginal change in adjusted funds from operations between the two periods.

Adjusted funds from operations decreased to $13.3 million in the year ended December 31, 2016 from $26.4 million in the same period in 2015. The decrease was primarily the result of the decrease in the operating netback and decreases in realized gains on derivative instruments, partially offset by the increase in production volumes.

Capital Expenditures[1]

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2016**	2015	**2016**	2015
Drilling and completion	**6,438**	7,149	**20,862**	10,789
Equipment, facilities and pipelines	**4,769**	1,940	**11,349**	2,944
Land	**7**	–	**762**	9,288
Capitalized overhead and other	**704**	720	**1,922**	1,756
Total expenditures	**11,918**	9,809	**34,895**	24,777
Proceeds from disposals of property	**—**	–	**(20)**	(150)
Total – net	**11,918**	9,809	**34,875**	24,627

During 2016, the Company focused its capital activities in the Wheatland area. In the fourth quarter of 2016, PPR drilled and completed 3 gross wells. PPR also completed, equipped and tied-in 4 gross wells that were drilled in the third quarter of 2016 and brought on-stream another 3 wells that were completed in the third quarter of 2016. For the 2016 calendar year, the Company drilled, completed and brought on-stream 12 gross wells from its 2016 14-well program. The 2 wells that were not on production by the end of the year came on production in February 2017. Together with the 4 gross wells drilled in 2015, total gross well count at Wheatland increased to 18 by the end of December 31, 2016 with 100% success rate. Aside from drilling, PPR has also invested in the construction of multi-well batteries and pipelines in the Wheatland area in the fourth quarter and year of 2016.

The year-to-date 2016 capital expenditures also incorporated $2.3 million spent the second phase of the Evi waterflood project, which included the conversion of producing wells to injection wells and pipeline expansion in the area.

Capital spending in the fourth quarter of 2015 was primarily comprised of drilling at Wheatland. Year-to-date 2015 capital expenditures additionally incorporated the acquisition of mineral leases in the Wheatland area for $9.3 million as well as capital activities in the Evi area, including electrification projects and well recompletion to enhance oil recovery.

Reorganization Costs

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2016**	2015	**2016**	2015
Salary and benefits – terminations	**—**	–	**382**	1,126
Share-based compensation - terminations	**—**	–	**—**	176
Professional fees	**—**	94	**10**	113
Total reorganization costs	**—**	94	**392**	1,415

Reorganization costs are non-recurring costs associated with the Company's corporate restructuring activities. For 2016 and 2015, the majority of the costs related to staff reductions. The 2016 reorganization costs were not related to the Arrangement.

[1] Capital expenditures include expenditures on E&E assets.

Transaction Costs

Transaction costs of $0.5 million and $2.3 million were incurred in the three months and year ended December 31, 2016, respectively, for the Arrangement. Transaction costs included primarily legal fees, professional fees and change of control settlements.

Decommissioning Liabilities

PPR's decommissioning liabilities at December 31, 2016 were $97.7 million (December 31, 2015 - $70.5 million) to provide for future remediation, abandonment and reclamation of the Company's oil and gas properties. The $27.2 million increase in decommissioning liabilities was primarily due to the Business Combination and change in estimates.

Decommissioning obligations acquired as part of the Business Combination amounted to $21.5 million, which were initially measured at fair value using a credit-adjusted risk free rate of 5.2% to discount estimated future cash flows. In accordance with PPR's accounting policy, decommissioning obligations are carried on the financial statements using risk-free discount rates. The revaluation of the acquired decommissioning obligations to the risk-free rates resulted in an increase to the carrying values of decommissioning liabilities by $15.2 million, which was included in changes in estimates. Partially offsetting the increase was an $8.9 million decrease due to changes in cost estimates that were recognized as of December 31, 2016. The remaining increase of $0.8 million during 2016 resulted from minor changes in other underlying assumptions. The changes in estimates resulted in a corresponding increase or decrease in the carrying amount of the related assets, except for certain assets with a zero carrying value, in which case, the amount was immediately recognized as an impairment charge.

The undiscounted future decommissioning costs, based on an inflation rate of 1.7%, are estimated at approximately $141.1 million. While the provision for decommissioning liabilities is based on management's best estimates of future costs, discount rates, timing and the economic lives of the assets, there is uncertainty regarding the amount and timing of incurring these costs.

Income Tax

At December 31, 2016, the Company had $325.7 million (December 31, 2015 – $141.2 million) of federal tax pools in Canada related to the exploration, development and production of oil and gas available for deduction against future Canadian taxable income. In addition, the Company had Canadian tax loss carry-forwards in the amount of $153.1 million (December 31, 2015 – $237.4 million), scheduled to expire in the years 2026 to 2036.

In 2015, the Canada Revenue Agency ("CRA") conducted an audit regarding the income tax treatment of compromised debt pertaining to the CCAA, as well as certain historic tax pools. In 2016, the CRA issued a final letter of adjustment that resulted in a reduction in tax pools of $59.4 million, of which $57.0 million was reflected in the 2015 provision with an additional $2.4 million reflected in the 2016 provision. The CRA's audit also resulted in the reclassification of various pools between Canadian exploration and development and non-capital losses.

As of December 31, 2016 and December 31, 2015, the Company did not recognize any deferred tax assets in the combined and consolidated statements of financial position for deductible temporary differences and unused tax losses as there was insufficient evidence to indicate that it was probable that future taxable profits in excess of profits arising from the reversal of existing temporary difference would be generated to utilize the existing deferred tax assts.

Capital Resources and Liquidity

Capital Resources

Working Capital

At December 31, 2016, the Company had working capital deficit (as defined in "Other Advisories" below) of $4.4 million (December 31, 2015 – working capital of $12.3 million). PPR acquired $6.8 million of working capital deficit through the Business Combination, $5.8 million of which related to a current tax liability that is expected to be paid in the second quarter of 2017. Increased capital expenditures during the year also contributed to the working capital deficit. PPR expects to fund its working capital deficit with cash flows from operations and borrowings under its Amended Credit Facility.

Amended Credit Facility

Under the Company's credit facility, PPR had outstanding long-term debt of $15.0 million (December 31, 2015 – $nil) and $5.4 million of letters of credit issued as at December 31, 2016 (December 31, 2015 – $4.5 million).

On September 12, 2016, the Company renewed and amended its credit facility with a syndicate of banks. Under the Amended Credit Facility, PPR has a $45 million syndicated revolving term facility and a $10 million operating facility, which mature one year after the term-out date. Annually prior to the applicable term-out date, subject to the lenders' approval, PPR may extend the term-out date by 364 days. The next term-out date is set at May 30, 2017; as such the maturity date of Amended Credit Facility is May 29, 2018. The Amended Credit Facility is collateralized by a demand debenture from PPR and each of its restricted subsidiaries in the amount of $500 million granting a first priority security interest over all present and after-acquired personal property and a first floating charge over all other present and after-acquired property, together with a fixed charge and mortgage over its existing borrowing base assets. A fixed charge and mortgage over after-acquired borrowing base assets will only be granted under certain circumstances.

The Amended Credit Facility includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends and mergers and acquisitions. The Amended Credit Facility also includes two financial covenants where at the end of each applicable quarterly period:

(i) total debt outstanding (including bank indebtedness and outstanding letters of credit) to Adjusted EBITDAX (as defined below) for a trailing 12-month period is required to be less than 3.0 to 1.0 (1.2 to 1.0 as at December 31, 2016); and

(ii) current assets to current liabilities (including available borrowing capacity and excluding derivative instruments) is required to be greater than 1.0 to 1.0 (2.0 to 1.0 as at December 31, 2016).

As at December 31, 2016, the Company was in compliance with all covenants under the Amended Credit Facility.

As at December 31, 2016, $0.4 million of deferred costs related to its outstanding credit facilities is net against long-term debt (December 31, 2015 – $0.6 million included in other assets and $0.2 million included in other long-term assets).

Shareholders' Equity

At December 31, 2016, PPR had consolidated share capital of $115.1 million (2015 – $73.9 million) and had 104.2 million outstanding common shares. In addition, PPR had 0.1 million RSUs (2015 – 1.4 million), 0.8 million (2015 – nil) options and 0.1 million (2015 – nil) PSUs (which will be settled subject to a performance multiplier from 0 to 2) outstanding as at December 31, 2016.

As of the date of the MD&A, there are 115.4 million common shares, nil RSU, 2.6 million stock options, 0.5 million PSUs (which will be settled subject to a performance multiplier from 0 to 2) and 3.0 million outstanding warrants (see Subsequent Events).

Preferred Shares

Pursuant to the Arrangement, all outstanding LPR Canada preferred shares ("Preferred Shares") were exchanged for PPR common shares at an exchange ratio of 0.81, whereby 60.9 million PPR common shares were issued. As the preferred shareholders were also common shareholders of PPR, the transaction was in substance an equity contribution to the Company. Upon the exchange, PPR derecognized the Preferred Shares liability and the Preferred Share conversion liability (collectively, "Preferred Share Liabilities") and recorded the PPR common shares at the carrying value of the Preferred Share Liabilities, resulting in an increase to the share capital of $193.9 million without any recognition of gains or losses.

Capital Management

PPR's objectives when managing capital is to maintain a flexible capital structure in order to meet its financial obligations and allow it to execute on its planned capital expenditure program. The Company's long-term goal is to fund current period decommissioning expenditures and capital expenditures necessary for the replacement of production declines using only funds from operations. Value-creating activities may be financed with a combination of funds from operations and other sources of capital. The Company considers its capital structure to include shareholders' equity, the Amended Credit Facility and working capital. PPR aims to manage the capital structure of the Company to provide a strong financial position that is capable of funding the future growth of the Company. The Company monitors the current and forecasted capital structure and makes adjustments on an ongoing basis in order to maintain the liquidity needed to satisfy the funding requirements of the Company. Modifications to the capital structure of the Company can be accomplished through issuing common shares, issuing new debt or replacing existing debt, adjusting capital spending and acquiring or disposing of assets.

The Company monitors its capital structure based on the ratio of total debt to trailing twelve months Adjusted EBITDAX (as defined in "Other Advisories" below). Total debt to Adjusted EBITDAX provides a measure of the Company's ability to manage its debt levels under current operating conditions. The ratio is calculated as total debt from the Amended Credit Facility divided by Adjusted EBITDAX for the most recent four consecutive fiscal quarters. The Company's goal is to manage this ratio well within the financial covenants imposed on it under the Amended Credit Facility. The Company also plans to maintain a prudent financial position by actively managing its capital program with careful consideration of the commodity pricing environment in order to optimize leverage, liquidity and cash flows.

Liquidity

The Company's has a borrowing capacity of $55 million under its Amended Credit Facility, of which $20.9 million was utilized as at December 31, 2016 including $5.4 million for the issuance of letters of credit, and a working capital deficit (as defined in "Other Advisories" below) of $4.4 million.

Subsequent to December 31, 2016, PPR acquired assets in the Great Red Earth area for cash consideration of $41.0 million, prior to closing adjustments. In conjunction with the closing of this acquisition, PPR issued flow-through common shares and common shares through a bought deal financing that raised gross proceeds of $8.0 million, which was used to fund the Red Earth Acquisition. The balance of the purchase price was funded with borrowings under the Amended Credit Facility, under which the borrowing capacity was increased to $65 million. Though PPR has increased its debt leverage significantly, PPR also expects its future funds flow to increase as a result of the Red Earth Acquisition. PPR anticipates its future development to be funded primarily with cash flows from operations, while maintaining a balanced leverage ratio.

PPR's management believes that with the high quality reserve base and development inventory, solid hedging program and steady base cash flows, the Company is well positioned to execute its business strategy. The Company remains committed to maintaining a strong financial position while continuing to maximize shareholder return through its long-term growth strategies. The Company has determined that its current financial obligations, including current commitments and working capital deficit are adequately funded from the available borrowing capacity and from cash flows derived from operations.

Contractual Obligations and Commitments

The Company has non-cancellable contractual obligations summarized as follows:

	2017	2018	2019	2020	2021	Thereafter	Total
Debt	384	15,207	—	—	—	—	15,591
Operating Leases – net	1,668	2,380	2,453	2,453	2,453	204	11,611
Firm transportation agreements	260	260	255	136	51	21	983
Capital commitments	13,382	20,250	—	—	—	—	33,632
Flow-through share commitment	4,945	—	—	—	—	—	4,945
Other agreements	429	45	39	41	38	407	999
Total	21,068	38,142	2,747	2,630	2,542	632	67,761

Included in operating leases – net are sublease recoveries in amount of $1.4 million over the contractual period.

The flow-through share commitment relates to flow-through shares issued by PPR in 2016 and will be met by incurring CEE and CDE as defined in the *Income Tax Act* and renouncing the related income tax deductions to investors.

Capital commitments relate to annual capital commitments for three years ending July 1, 2018 pursuant to a lease acquisition agreement as described below. The capital commitments and flow-through share commitment may be fulfilled by the same exploration expenditures.

In addition, the Company has estimated future decommissioning liabilities on its interests in wells and facilities in the total amount of $141.1 million on an undiscounted basis, inflated at 1.7%, of which, $15.5 million is estimated to be incurred over the next five years.

Capital Commitments

Lease Acquisition Capital Commitment

Under the lease acquisition capital commitment, the Company is committed to annual capital expenditures for three years ending July 1, 2018 pursuant to the acquisition of 69,000 net undeveloped acres in the Wheatland area. During the third quarter of 2016, the lease acquisition agreement was amended whereby an additional approximate 4,500 net acres of undeveloped land in the Wheatland area were purchased for $0.6 million. The Company can meet its original capital commitment by incurring costs related to the additional undeveloped land purchased as well as on the lands purchased under the original agreement. In the event that PPR does not incur the minimum capital expenditures by the end of a given commitment period, the shortfall will be payable to the vendor. If the amount of capital expenditures incurred for any commitment period exceeds the minimal amount, such excess will be applied to satisfy capital commitment in the subsequent commitment period. During the first two years of the leases, if the average WTI prices for a calendar quarter are below US$50/bbl, PPR may defer a portion of the drilling commitment from that commitment period to be allocated over the remaining term. Averaged WTI prices for the first two calendar quarters of the second commitment period were below US$50/bbl, as such, the deferrable option is exercisable. On or before July 1, 2017, if PPR fails to drill or to elect to drill one well in a specific formation on certain lands, PPR will be required to surrender the leases pertaining to the Specific Formation immediately. In the event that the Company made the election but does not drill by July 1, 2018, $250,000 will be payable to the vendor.

As of December 31, 2016, the capital commitment for the year ending July 1, 2016 of $10.0 million was met and additional spending of $1.6 million has been applied towards the July 1, 2017 capital commitment of $15.0 million. In the first quarter of 2017, an additional $3.6 million has been incurred by drilling 3 wells in Wheatland, with $2.2 million expected to be spent towards these 3 wells in the second quarter of 2017. PPR expects to fulfill the remaining capital commitment through its capital program at the Wheatland area. The deferral option noted above, if exercised, will provide some flexibility around the timing of incurrence of such expenditures.

Farm-in Arrangement Capital Commitment

Under the farm-in arrangement capital commitment, a minimum of $20 million of drilling and completion expenditures (the "Gross Capital Commitment") must be incurred on farm-in lands by December 31, 2016. Depending on the participation of the farmor, the Company's share of the expenditures may be between 50% and 100% of the Gross Capital Commitment. In the second quarter of 2016, the farm-in and option agreement was amended to allow more flexibility of timing on drilling test wells and option wells throughout 2016 and 2017. As at December 31, 2016, the full Gross Capital Commitment has been met. Under the terms of the amended arrangement, PPR may continue to drill test and option wells on the farm-in lands until December 31, 2017. The farmor may elect to participate up to a 50% working interest on earnings and test wells. There is no further capital spending commitments under this agreement.

Off Balance Sheet Transactions

There were no off balance sheet transactions entered into during the period, nor are there any outstanding as of the date of this MD&A.

Supplemental Information

Financial – Quarterly extracted information

($000)	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Q4	2015 Q3	2015 Q2	2015 Q1
Oil and natural gas revenue	17,060	9,334	9,151	7,203	8,783	9,191	11,591	9,770
Royalties	(2,270)	(1,050)	(924)	(649)	(746)	(575)	(323)	(546)
Unrealized (loss) gain on derivatives	(7,231)	(1,936)	(10,959)	852	(730)	4,118	(6,650)	(3,581)
Realized gain on derivatives	1,362	2,257	2,539	3,585	4,921	4,421	3,063	4,380
Revenue net of realized and unrealized gains (losses) on derivative instruments	8,921	8,605	(193)	10,991	12,228	17,155	7,681	10,023
Adjusted funds from operations [(1)]	7,107	1,810	3,252	1,090	7,007	5,925	8,012	5,437
Per share – basic [(2)]	0.07	0.02	0.03	0.01	0.07	0.06	0.08	0.06
Per share – diluted [(3)]	0.07	0.02	0.03	0.01	0.07	0.06	0.08	0.06
Net earnings (loss)	(8,782)	(11,588)	(43,223)	3,197	(15,390)	(12,985)	(9,929)	(21,590)
Per share – basic [(4)]	(0.09)	(0.12)	(0.44)	0.03	(0.16)	(0.13)	(0.10)	(0.22)
Per share – diluted [(5)]	(0.09)	(0.12)	(0.44)	0.03	(0.16)	(0.13)	(0.10)	(0.22)

1 Adjusted funds from operations is a non-IFRS measure and is defined below under "Other Advisories".

2,3,4,5 As the historical financial statements were prepared on a combined and consolidated basis it is not possible to measure per share amounts until subsequent to the closing of the Arrangement on September 12, 2016 when Lone Pine and Arsenal were brought under a common parent entity. The Company calculated per share information for the current and historical periods by assuming that the common shares issued upon the closing of the Arrangement at September 12, 2016 were outstanding since the beginning of the period. Diluted per share information is calculated with consideration to the effect of outstanding restricted share units as converted to PPR equivalent units.

Over the past eight quarters, the Company's oil and natural gas revenue have fluctuated primarily due to changes in production and movement in the commodity prices. The Company's production has varied due to its successful capital development program at Wheatland, the Business Combination and natural declines. Movements in oil and natural gas revenue attributable to fluctuations in commodity prices were partially mitigated by realized gain on derivatives, even though there were significant swings in unrealized gains/losses on derivatives. Despite earning positive adjusted funds from operations in the past eight quarters, the Company incurred net losses due to non-cash expenses, including unrealized derivative losses, impairments to D&P and E&E assets, DD&A, and accretion expense and foreign exchange losses related to the Preferred Shares. As the Preferred Shares were exchanged for PPR common shares upon the Arrangement, accretion expense and foreign exchange gains/losses should be reduced considerably in the future.

Oil and natural gas revenue and adjusted funds from operations increased significantly in the fourth quarter of 2016 as production peaked, coupled with recovery of commodity prices from the previous four quarters. The net loss of $8.8 million in the fourth quarter of 2016 was attributable to unrealized losses on derivative instruments of $7.2 million and depletion and depreciation of $7.4 million.

The net loss of $11.6 million in the third quarter of 2016 was the result of non-cash expenses including impairment of $1.7 million, non-cash accretion of $3.5 million, unrealized losses on derivative instruments of $1.9 million and depletion and depreciation of $4.2 million, which exceeded adjusted funds from operations.

PPR experienced $43.2 million of net loss in the second quarter of 2016, the most significant in the past 8 quarters, mainly due to the recognition of $25.0 million impairment charges against its E&E assets in Quebec and unrealized losses on derivative instruments of $11.0 million.

The net earnings of $3.2 million in the first quarter of 2016 was primarily the result of unrealized foreign exchange gains of $10.7 million related to the translation of the US dollar denominated preferred share liability and realized gains on derivative instruments of $3.6 million.

Adjusted funds from operations for the four quarters in 2015 were relatively stable, though net losses fluctuated from quarter to quarter primarily due to the significant movements in unrealized derivative gains/losses and foreign exchange gains/losses as a result of changes in forward commodity prices and US/CAD exchange rates.

Annual Selected Financial and Operational Information

($000s except per unit amounts)	**2016**	2015	2014
Financial			
Oil and natural gas revenue	**42,748**	39,335	111,467
Net loss	**(60,396)**	(59,894)	(73,395)
Per share – basic & diluted[1]	**(0.62)**	(0.61)	(0.75)
Adjusted Funds from operations[2]	**13,259**	26,382	41,926
Per share – basic & diluted[3]	**0.14**	0.27	0.43
Net capital expenditures (dispositions)[4]	**34,875**	24,627	(66,356)
Corporate acquisitions of P&D assets	**67,065**	–	–
Total assets	**247,835**	198,905	207,192
Total liabilities	**145,249**	272,967	222,619
Long-term debt	**15,047**	–	–
Preferred shares liability	**—**	166,171	126,625
Preferred shares – conversion liability	**—**	26,450	26,450
Weighted average shares outstanding			
Basic & diluted[5]	**97,868**	97,409	97,409
Operating			
Production Volumes			
Crude oil (bbls/d)	**2,012**	1,820	2,257
Natural gas (Mcf/d)	**9,253**	4,577	21,489
Natural gas liquids (bbls/d)	**126**	69	86
Total (boe/d)	**3,680**	2,652	5,925
% Liquids	**58%**	71%	40%
Average Realized Prices			
Crude oil ($/bbl)	**46.75**	51.24	89.42
Natural gas ($/Mcf)	**2.21**	3.01	4.62
Natural gas liquids ($/bbl)	**17.91**	10.76	50.25
Total ($/boe)	**31.74**	40.64	51.55
Operating Netback ($/boe)[6]			
Realized price	**31.74**	40.64	51.55
Royalties	**(3.63)**	(2.26)	(6.22)
Operating costs	**(17.39)**	(16.49)	(16.55)
Operating netback	**10.72**	21.89	28.78
Realized gains on derivative instruments	**7.23**	17.34	(3.11)
Operating netback, after realized gains on derivative instruments	**17.95**	39.23	25.67

[1,3,5] As the historical financial statements were prepared on a combined and consolidated basis it is not possible to measure per share amounts until subsequent to the closing of the Arrangement on September 12, 2016 when Lone Pine and Arsenal were brought under a common parent entity. The Company calculated per share information for the current and historical periods by assuming that the common shares issued upon the closing of the Arrangement at September 12, 2016 were outstanding since the beginning of the period. Diluted per share information is calculated with consideration to the effect of outstanding restricted share units as converted to PPR equivalent units.

[2,6] Adjusted funds from operations and Operating Netback are non-IFRS measures and are defined below under "Other Advisories".

[4] Net capital expenditures (disposition) include expenditures on E&E assets.

On August 12, 2014, the Company disposed of its assets in the Deep Basin CGU for cash proceeds of $110.4 million net of disposition costs. The Deep Basin CGU was comprised of gas weighted undeveloped and developed properties. This disposition, combined with significant declines in commodity reference prices resulted in a significant decrease in oil and natural gas revenue from 2014 to 2015. The disposition of the gas weighted properties also resulted in a significant increase in our liquids weighting.

In 2015 and 2016 the Company has focused capital expenditure on a drilling program in the Wheatland area. The Wheatland drilling program coupled with the Arsenal acquisition resulted in increased production and revenue in 2016 compared to 2015 despite a decrease in realized crude oil and natural gas prices.

Internal Control over Financial Reporting and Officer Certifications

Internal control over financial reporting is a process designed to provide reasonable assurance that all the assets are safeguarded and transactions are appropriately authorized, and to facilitate the preparation of relevant, reliable and timely information. Due to inherent limitations, internal control over financial reporting may not prevent or detect all misstatements due to fraud or error.

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in NI 52-109. The control framework PPR's officers used to design and evaluate the Company's internal controls over financial reporting is the Internal Control – Integrated Framework (2013) by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on their evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's internal controls over financial reporting were effective as of December 31, 2016. There have been no changes in the Company's internal controls over financial reporting during the period from January 1, 2016 to December 31, 2016 that have materially affected, or are reasonably likely to materially affect the Company's internal controls over financial reporting.

Changes in Accounting Policies

The 2016 Annual Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2016.

The following new or amended accounting standards and pronouncements issued are applicable to PPR in future periods:

- In July 2014, the IASB completed the final elements of IFRS 9 - Financial Instruments. The Standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 - Financial Instruments: Recognition and Measurement. IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The Standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. The Company plans to adopt IFRS 9 on a retrospective basis on January 1, 2018. Based on a preliminary assessment, The Company does not expect to have the 'expected loss' impairment model to have a material impact on its consolidated financial statements. The Company does not currently apply hedge accounting to its derivative financial instruments and does not expect to apply hedge accounting upon adoption of IFRS 9;

- In May 2014, the IASB published IFRS 15 – Revenue from Contracts with Customers ("IFRS 15") replacing IAS 11 – Construction Contracts, IAS 18 – Revenue and several revenue-related interpretations. The new standard establishes a single revenue recognition framework that applies to contracts with customers and requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. IFRS 15 is effective for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company plans to adopt IFRS 15 on January 1, 2018. The Company is in the process of reviewing its revenue streams and underlying contracts with customers to evaluate the impact, if any, adoption will have on the consolidated financial statements and disclosures; and

- In January 2016, the IASB issued IFRS 16 - Leases, which replaces IAS 17 – Leases. For lessees, IFRS 16 removes the classification of leases as financing or operating leases, effectively treating all leases as finance leases which requires the recognition of lease assets and lease obligations. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements and may continue to be treated as operating leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 Revenue from Contracts with Customers. The Company is currently evaluating the impact of the standard on its financial statements.

- In January 2016, the IASB issued an amendment to IAS 7 Statement of Cash Flows. The amendment to IAS 7 requires additional disclosures for changes in liabilities arising from financing activities. This includes changes arising from cash flows, such as drawdowns and repayments of borrowings, and non-cash changes, such as acquisitions, disposals and unrealized exchange differences. The amendment is effective for fiscal years beginning on or after January 1, 2017, and is applied on a prospective basis. The adoption of this standard is not expected to have a material impact on the company's disclosures.

Critical Accounting Estimates

The preparation of financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, revenues and expenses. 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.

- PPR's oil and gas assets are grouped into cash generating units ("CGUs"). A CGU is the lowest level of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgement and interpretations with respect to the integration between assets, geological formation, geographical proximity, the existence of common sales points and shared infrastructures and the way in which management monitors its operations. The recoverability of the PPR's oil and gas assets is assessed at the CGU level, and therefore, the determination of a CGU could have a significant impact on impairment losses or impairment reversals;

- Reserve engineering is an inherently complex and subjective process of estimating underground accumulations of petroleum and natural gas. The process relies on interpretations of available geological, geophysical, engineering, economic and production data. The accuracy of a reserves estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various economic assumptions and the judgement of those preparing the estimate. Because these estimates depend on many assumptions, all of which may differ from actual results, reserves estimates and estimates of future net revenue may be different from the sales volumes ultimately recovered and net revenues actually realized. Changes in market conditions, regulatory matters and the results of subsequent drilling, testing and production may require revisions to the original estimates. Estimates of reserves impact: (i) the assessment of whether or not a new well has found economically recoverable reserves; (ii) depletion rates; (iii) the determination of net recoverable amount of oil and gas properties for impairment assessment and measurement, and (iv) the determination of reserve lives which affect the timing of decommissioning activities, all of which could have a material impact on earnings and financial positions;

- Recoverable amounts calculated for impairment testing are based on estimates of future commodity prices, expected volumes, quantity of reserves and discount rates as well as future development costs and operating costs. These calculations require the use of estimates and assumptions, which by their nature, are subject to measurement uncertainty. In addition, judgement is exercised by management as to whether there have been indicators of impairment or of impairment reversal. Indicators of impairment or impairment reversal may include, but are not limited to a change in: market value of assets, estimate of future prices and costs, a change in estimated quantity of reserves and appropriate discount rates;

- Business combinations are accounted for using the acquisition method of accounting where the acquired assets, liabilities and consideration issued were all fair valued. The determination of fair value requires the use of assumptions and estimates related to future events. The valuation of property and equipment includes key assumptions and estimates related to oil and gas reserves acquired, forecasted commodity prices, expected production volumes, future development costs, operating costs and discount rates. The valuation of exploration and evaluation assets includes key assumptions and estimates related to recent transactions on similar assets considering geographic location and risk profile. The valuation of the decommissioning liabilities and other liabilities includes estimates related to the timing and amount of anticipated cash outflows as well as for inflation rates and discount rates. As PPR common shares were issued in exchange for AEI's common shares, PPR common shares were fair valued with reference to PPR's enterprise value, which in turn was determined by fair valuing PPR's underlying assets and liabilities. Key assumptions used to fair value PPR's assets and liabilities were similar to the ones mentioned above. In addition, PPR's enterprise value was calibrated against trading metrics of recent market transactions for reasonableness. Changes in assumptions and estimates used in the determination of assets and liabilities acquired and consideration issued could result in changes to the values assigned to the assets, liabilities and goodwill or a bargain purchase gain. This could in turn impact future earnings or loss as a result of changes in the realization of assets value or settlement of liabilities;

- Amounts recorded for decommissioning liabilities and the related accretion expense require the use of estimates with respect to the amount and timing of decommissioning expenditures, inflation rates and discount rates. Actual costs and cash outflows can differ from estimates because of changes in law and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology. Decommissioning liabilities are recognized in the period when it becomes probable that there will be a future cash outflow;

- Compensation costs recorded pursuant to share-based compensation plans are subject to the estimated fair values of the awards on the grant date and the estimated number of units that will ultimately vest. The Company uses the Black-Scholes option pricing model to estimate the fair value of options, which requires the Company to determine the most appropriate inputs including the expected life of the options, volatility, forfeiture rates and future dividends, which by nature, are subject to measurement uncertainty. The determination of the fair value of performance share units requires the estimation of the performance multiplier from 0 to 2 on the grant date;

- Derivative risk management contracts are valued using valuation techniques with market observable inputs. The most frequently applied valuation techniques include forward pricing and swap models, using present value calculations. The models incorporate various inputs including the credit quality of counterparties, foreign exchange spot and forward rates, and forward rate curves of the underlying commodity. Changes in any of these assumptions would impact fair value of the risk management contracts and as a result, future net income and other comprehensive income;

- Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. The Company is also subject to income tax audits and reassessments which may change its provision for income taxes. Therefore, the determination of income taxes is by nature complex, and requires making certain estimates and assumptions. PPR recognizes net deferred tax benefit related to deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the net deferred tax assets recorded at the reporting date could be impacted;

- The determination of fair value requires judgement and is based on market information, where available and appropriate. Fair value is best evidenced by an independent quoted market price for the same asset or liability in an active market. However, quoted market prices and active markets do not always exist. In those instances, fair valuation techniques are used. The Company applies judgement in determining the most appropriate inputs and the weighting ascribed to each such input as well as its selection of valuation methodologies. The calculation of fair value is based on market conditions as at each reporting date, and may not be reflective of ultimate realizable value;

- 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; and

- Amounts recorded for capitalized general and administrative cost that is related to directly attributed supporting functions and activity to post license exploration and evaluation assets and to development and producing CGU properties requires the use of estimates and judgements and is by its nature subject to measurement uncertainty.

Operational and Other Risk Factors

PPR's operations are conducted in the same business environment as most other oil and gas operators and the business risks are very similar. Significant risks are summarized below. Additional risks are provided in the "Risk Factors" section of the 2016 Annual Information Form filed on SEDAR at www.sedar.com.

Risks Associated with Commodity Prices

- PPR's operational results and financial condition, and therefore the amount of capital expenditures are dependent on the prices received for crude oil and natural gas production. Decreasing crude oil and natural gas prices and/or widening of oil price differentials will affect the Company's cash flows, impact its level of capital expenditures and may result in the shut-in of certain producing properties. Longer-term adverse forward pricing outlook could also result in write-down of the Company's oil and gas assets' carrying values.

- The Amended Credit Facility has a reserves-based borrowing capacity. Decreases in future commodity prices may negatively impact the borrowing capacity and restrict PPR's liquidity.

- PPR may manage the risk associated with changes in commodity prices by entering into crude oil or natural gas price derivative contracts. If PPR engages in activities to manage its commodity price exposure, it may forego the benefits it would otherwise experience if commodity prices were to increase. In addition, commodity derivative contracts activities could expose the Company to losses. To the extent that PPR engages in risk management activities related to commodity prices, it would be subject to credit risks associated with counterparties with which it contracts.

Risks Associated with Operations

- The markets for crude oil and natural gas produced in Western Canada are dependent upon available capacity to refine crude oil and process natural gas as well as pipeline or other methods to transport the products to consumers. Pipeline capacity and natural gas liquids fractionation capacity in Alberta have not kept pace with the drilling of liquid rich gas properties in some areas of the province which may limit production periodically.

- Exploration and development activities may not yield anticipated production, and the associated cost outlay may not be recovered. In addition, the costs and expenses of drilling, completing and operating wells are often uncertain.

- Continuing production from a property are largely dependent upon the ability of the operator of the property. A portion of PPR's production is either operated by third parties or dependent on third party's infrastructure, PPR has limited ability to influence costs on partner-operated properties. To the extent the operator fails to perform their duties properly, PPR's operating income from such properties may be reduced.

- Exploration and development activities are dependent on the availability of drilling, completion and related equipment in the particular areas where the activities are conducted. Demand for limited equipment or access restrictions may negatively impact the availability of such equipment to PPR and delay exploration and development activities.

- The operations of oil and gas properties involves a number of operating and natural hazards which may result in health and safety incidents, environmental damage and other unexpected and/or dangerous conditions.

- The operations of oil and gas properties are subject to environmental regulation pursuant to local, provincial and federal legislation. Changes in these regulations could have a material adverse effect as regards to operating costs and capital costs. A breach of such legislation may result in the imposition of fines as well as higher operating standards that may increase costs. Public support for climate change action has grown in recent years. Governments in Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation. Existing and future laws and regulations may impose significant compliance costs or liabilities on a failure to comply requirements.

- PPR's corporate environment, health and safety program has a number of specific policies and practices to minimize the risk of safety hazards and environmental incidents. It also includes an emergency response program should an incident occur. If areas of higher risk are identified, PPR will undertake to analyze and recommend changes to reduce the risk including replacement of specific infrastructure. In addition to the above, PPR maintains business interruption insurance, commercial general liability insurance as well as specific environmental liability insurance, in amounts consistent with industry standards. Though PPR carries industry standard property and liability insurance on its properties, losses associated with potential incidents could exceed insurance coverage limits.

Risks Associated with Reserve Estimates

- The reservoir and recovery information in reserve reports prepared by independent reserve evaluators are estimates and actual production and recovery rates may vary from the estimates and the variations may be significant. Reserves estimation process is inherently complex and subjective. The process relies on interpretations of available geological, geophysical, engineering, economic and production data. The accuracy of a reserves estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various economic assumptions and the judgement of those preparing the estimate. Reserves data impacts not only PPR’s financial statements, but business decisions such as merger and acquisition, assessment of capital projects for development and budgeting. Uncertainties around reserves estimates could have profound impact to PPR’s financial positions, operating performance and strategic plans.

Risks Associated with Capital Resources

- Absent capital reinvestment or acquisition, PPR’s reserves and production levels from petroleum and natural gas properties will decline over time as a result of natural declines. As a result, cash generated from operating these properties may decline. Decreased reserves level will also negatively impact the borrowing base under outstanding credit facilities.

- PPR is required to comply with covenants under the Amended Credit Facility. In the event that the Company does not comply with the covenants, its access to capital may be restricted. Any additional indebtedness brings the Company closer to its financial covenant limits under the credit facility, which increases the possibility of adverse changes in revenues, expenses, assets or liabilities resulting in non-compliance with financial covenants. Any such future non-compliance could result in adverse action by the lenders, including the imposition of limits on further borrowing.

- There have been high levels of price and volume volatility of publicly traded securities in the last couple of years, especially in the oil and natural gas exploration and development industry. Fluctuations in prices have not necessarily been related to the operating performance, underlying asset values or prospect of such companies. Market fluctuations may hinder the Company’s ability to raise equity.

- To the extent that external sources of capital become limited or unavailable or available on onerous terms, PPR's ability to make capital investments, meet its capital commitments pursuant to the Wheatland Acquisition and flow-through share commitments, and maintain or expand existing assets and reserves may be impaired and PPR's assets, liabilities, business, financial condition, and results of operations may be materially or adversely affected as a result.

- Fluctuations in interest rates could result in increases in the amount PPR pays to service future debt. World oil prices are quoted in US dollars and the price received by Canadian producers is therefore affected by the Canadian/US dollar exchange rate. A material increase in the value of the Canadian dollar may negatively impact PPR’s net production revenue.

- Although the Company monitors the credit worthiness of third parties it contracts, there can be no assurance that the Company will not experience a loss for nonperformance by any counterparty with whom it has a commercial relationship. Such events may result in material adverse consequences on the business of the Company.

Risks Associated with Acquisitions

- Acquisitions of oil and gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquirer, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the Company's control. All such assessments involve a measure of geological, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

- Although select title and environmental reviews are conducted prior to any purchase of resource assets, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat the Company's title to certain assets or that environmental defects, liabilities or deficiencies do not exist or are greater than anticipated. Such deficiencies or defects could adversely affect the value of the Assets and the Company's securities.

- There may be liabilities that the Company failed to discover or was unable to quantify in its due diligence review conducted prior to the execution of an acquisition, and which could have a material adverse effect on the Company's business, financial condition or future prospects.

- Achieving the benefits of an acquisition depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the Company's ability to realize the anticipated growth opportunities and synergies from integrating the assets into its existing portfolio of properties. The integration of the assets requires the dedication of substantial management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the disruption of ongoing business, customer and employee relationships that may adversely affect its ability to achieve the anticipated benefits of the acquisition.

General Business Risks

- The operations of PPR are conducted under permits issued by the federal and provincial governments and these permits must be renewed periodically. The federal and provincial governments may make operating requirements more stringent, which may require additional spending.

- Provincial programs, including royalty regimes and environmental regulations, related to the oil and gas industry may change in a manner that adversely impacts the Company. Future amendments to any of these programs could result in reduced cash flow and operating results.

- The use of fracture stimulations has been ongoing safely in an environmentally responsible manner in Western Canada for decades. With the increase in the use of fracture stimulations in horizontal wells, there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology. This increased attention to fracture stimulations may result in increased regulation or changes of law, which may make the conduct of PPR’s business more expensive or prevent the Company from conducting its business as currently conducted.

- The operation of oil and gas properties requires physical access for people and equipment on a regular basis, which could be affected by weather, accidents, government regulations or third party actions.

- Skilled labor is necessary to run operations (both those employed directly by PPR and by our contractors) and there is a risk that we may have difficulty in sourcing skilled labor which could lead to increased operating and capital costs.

- The loss of a member of our senior management team and/or key technical operations employee could result in a disruption to our operations.

- Income tax laws, other laws or government incentive programs relating to the oil and gas industry, may in the future be changed or interpreted in a manner that affects PPR or its stakeholders.

- The Company has become increasingly dependent on the availability, capacity, reliability and security of its information technology (IT) systems and infrastructure. Should access to these systems be significantly interrupted, the operations of the Company could be disrupted.

Forward-Looking Statements

Certain statements and information in this MD&A may constitute forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond the Company's control. All statements regarding the Company's strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. The words "could," "believe," "anticipate," "intend," "plan," "estimate," "expect," "may," "continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements with respect to, among other things:

- estimates of the Company's oil and natural gas reserves;
- estimates of the Company's future oil, natural gas and NGL production, including estimates of any increases or decreases in the Company's production;
- estimates of future capital expenditures;
- estimates and judgements related to common shares and preferred shares valuations;
- the Company's future financial condition and results of operations;
- the source of funding for the Company's activities, including development costs;
- the Company's ability to meet its capital commitment;
- the Company's future revenues, cash flows and expenses;
- the Company's access to capital and expectations with respect to liquidity and capital resources;
- the Company's future business strategy and other plans and objectives for future operations;
- the Company's future development opportunities and production mix;
- the Company's outlook on oil, natural gas and NGL prices;
- the anticipated benefits of merger and acquisitions;
- the Company's ability to incur CEE;
- the amount, nature and timing of future capital expenditures, including future development costs;
- the Company's ability to access the capital markets to fund capital and other expenditures;
- The company's expectations regarding the Company's ability to raise capital and to add reserves and grow production
- through acquisitions, exploration and development;the Company's assessment of the Company's counterparty risk and the ability of the Company's counterparties to perform their future obligations; and

- the impact of federal, provincial, territorial and local political, legislative, regulatory and environmental developments in Canada.

PPR believes the expectations and forecasts reflected in the Company's forward-looking statements are reasonable, but PPR can give no assurance that they will prove to be correct. Readers are cautioned that these forward-looking statements can be affected by inaccurate assumptions and are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control, incident to the exploration for and development, production and sale of oil and natural gas. When considering forward-looking statements, you should keep in mind the assumptions, risk factors and other cautionary statements that include, among other things:

- the volatility of oil, natural gas and NGL prices, and the related differentials between realized prices and benchmark prices;
- a continuation of depressed natural gas prices;
- the availability of capital on economic terms to fund the Company's significant capital expenditures and acquisitions;
- the Company's ability to obtain adequate financing to pursue other business opportunities;
- the Company's ability to generate sufficient cash flow from operations or obtain adequate financing to fund the Company's capital expenditures and meet working capital needs;
- the Company's ability to replace and sustain production;
- a lack of available drilling and production equipment, and related services and labor;
- the Company's ability to successfully integrate the acquired assets;
- increases in costs of drilling, completion and production equipment and related services and labor;
- unsuccessful exploration and development drilling activities;
- regulatory and environmental risks associated with exploration, drilling and production activities;
- declines in the value of the Company's oil and natural gas properties, resulting in impairments;
- the adverse effects of changes in applicable tax, environmental and other regulatory legislation;
- a deterioration in the demand for the Company's products;
- the risks and uncertainties inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and the timing of expenditures;
- the risks of conducting exploratory drilling operations in new or emerging plays;
- intense competition with companies with greater access to capital and staffing resources;
- the risks of conducting operations in Canada and the impact of pricing differentials, fluctuations in foreign currency exchange rates and political developments on the financial results of the Company's operations; and
- the uncertainty related to the pending litigation against us.

Should one or more of the risks or uncertainties described above or elsewhere in this MD&A occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking statements. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this MD&A, and the Company undertakes no obligation to update this information to reflect events or circumstances after the delivery of this MD&A. All forward-looking statements, expressed or implied, included in this MD&A are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that the Company may make or persons acting on the Company's behalf may issue.

Other Advisories

Volumetric Conversion

The oil and gas industry commonly expresses production volumes and reserves on a “barrel of oil equivalent” basis (“boe”) whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants.

Throughout the MD&A, the Company has used the 6:1 boe measure, which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the wellhead nor at the plant gate, which is where PPR sells its production volumes and therefore may be a misleading measure, particularly if used in isolation. Given that the value ration based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion may be misleading as an indication of value.

Non-IFRS Measures

The Company uses terms within the MD&A that do not have a standardized prescribed meaning under IFRS and these measurements may not be comparable with the calculation of similar measurements used by other companies. The non-IFRS measures used in this report are summarized as follows:

Working Capital

Working capital (deficit) is calculated as current assets less current liabilities excluding the current portion of derivative instruments, the current portion of decommissioning liabilities and the flow-through share premium. This measure is used to assist management and investors in understanding liquidity at a specific point in time. The current portion of derivatives instruments is excluded as management intends to hold derivative contracts through to maturity rather than realizing the value at a point in time through liquidation. The current portion of decommissioning expenditures is excluded as these costs are discretionary and the current portion of flow-through share premium liabilities are excluded as it is a non-monetary liability.

The following table provides a calculation of working capital (deficit):

($000s)	**December 31, 2016**	December 31, 2015
Current assets	**17,539**	30,744
Less current derivative instrument assets	**—**	(9,531)
Current assets excluding current derivatives instruments	**17,539**	21,213
Current liabilities	**28,120**	12,445
Less flow-through share premium	**(390)**	—
Less current derivative instrument liabilities	**(2,311)**	—
Less current portion of decommissioning liability	**(3,500)**	(3,500)
Current assets excluding current derivatives instruments and current portion of decommissioning liabilities	**21,919**	8,945
Working capital (deficit)	**(4,380)**	12,268

Operating Netback

Operating netback is a non-IFRS measure commonly used in the oil and gas industry. This measurement assists management and investors to evaluate the specific operating performance at the oil and gas lease level. Operating netbacks included in this report were determined by taking (oil and gas revenues less royalties less operating costs) divided by gross working interest production. Operating netback, including realized commodity (loss) and gain, adjusts the operating netback for only realized gains and losses on derivative instruments.

Adjusted Funds from Operations

Adjusted funds from operations is calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs, restructuring costs, decommissioning expenditures and other non-recurring items. Management believes that such a measure provides an insightful assessment of PPR's operation performance on a continuing basis by eliminating certain non-cash charges and charges that are non-recurring or discretionary and utilizes the measure to assess its ability to finance operating activities, capital expenditures and debt repayments. Adjusted funds from operations as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. Adjusted funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings per share.

The following table reconciles cash flow from operating activities to adjusted funds from operations:

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2016**	2015	**2016**	2015
Cash flow from operating activities	**3,623**	5,649	**8,145**	20,767
Changes in non-cash working capital	**1,289**	915	**(2,539)**	2,348
Funds from Operations	**4,912**	6,564	**5,606**	23,115
Other	**23**	(107)	**433**	463
Settlement of decommissioning liabilities	**1,657**	456	**4,540**	1,389
Restructuring costs	**—**	94	**392**	1,415
Transaction costs	**515**	—	**2,288**	—
Adjusted Funds from Operations	**7,107**	7,007	**13,259**	26,382

Adjusted EBITDAX

The Company monitors its capital structure and liquidity based on the ratio of Debt to Adjusted EBITDAX as defined below. The ratio provides a measure of the Company's ability to manage its debt levels under current operating conditions. "Debt" refers to the Company's borrowings under its Amended Credit Facility. "Adjusted EBITDAX" corresponds to defined terms in the Company's credit facility agreement and means net earnings before financing charges, foreign exchange gain (loss), E&E expense, income taxes, depreciation, depletion, amortization, other non-cash items of expense and non-recurring items, adjusted for major acquisitions and material dispositions assuming that such transactions had occurred on the first day of the applicable calculation period. As transaction costs related to the Arrangement are non-recurring costs, Adjusted EBITDAX has been calculated, excluding transaction costs, as a meaningful measure of continuing operating cash flows. For purposes of calculating covenants under the credit facility, Adjusted EBITDAX is determined using financial information from the most recent four consecutive fiscal quarters.

The following is a reconciliation of Adjusted EBITDAX to the nearest IFRS measure, net loss before income tax:

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2016**	2015	**2016**	2015
Net loss before income tax	**(8,796)**	(15,332)	**(60,410)**	(59,836)
Add (deduct):				
Interest	**230**	169	**730**	828
Depletion and depreciation	**7,409**	3,789	**21,344**	21,436
Exploration and evaluation expense	**9**	379	**58**	545
EBITDAX	**(1,148)**	(10,995)	**(38,278)**	(37,027)
Unrealized (gain) loss on derivative instruments	**7,231**	730	**19,274**	6,843
Impairment loss	**(54)**	7,804	**26,723**	13,298
Accretion	**451**	4,049	**12,389**	15,317
Loss (gain) on foreign exchange	**215**	5,287	**(9,510)**	25,498
Reorganization costs[1]	**—**	94	**392**	1,415
Share-based compensation	**177**	169	**366**	1,041
Loss on sale of properties	**—**	—	**73**	197
Transaction costs	**515**	—	**2,288**	—
Pro-forma impact of acquisition	**—**	—	**3,206**	—
Adjusted EBITDAX	**7,387**	7,138	**16,923**	26,582

[1] Reorganization cost includes share-based compensation related to terminations.