Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three and Six Months Ended June 30, 2017

Dated: August 9, 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. ("Arsenal"). 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 after September 12, 2016. See "Arrangement Agreement" section for details.

The following MD&A provides management's analysis of the Company's results of operations, financial position and outlook as at and for the three and six months ended June 30, 2017. This MD&A is dated August 9, 2017 and should be read in conjunction with the audited consolidated financial statements of PPR as at and for the year ended December 31, 2016 (the "2016 Annual Financial Statements") and the 2016 annual MD&A (the "Annual MD&A"), both dated March 30, 2017. 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
P&D	production and development
PSU	performance share unit
DSU	deferred restricted share unit
RSU	restricted share unit
WTI	West Texas Intermediate

Financial and Operational Highlights

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s except per unit amounts)	**2017**	2016	**2017**	2016
Financial				
Oil and natural gas revenue	**21,682**	9,151	**40,890**	16,354
Net earnings (loss)	**1,066**	(43,223)	**8,328**	(40,026)
Per share – basic	**0.01**	(0.44)	**0.08**	(0.41)
Per share – diluted	**0.01**	(0.44)	**0.07**	(0.41)
Adjusted Funds from Operations[1]	**7,060**	3,252	**12,994**	4,342
Per share – basic & diluted	**0.06**	0.03	**0.12**	0.04
Capital expenditures and acquisitions (net of proceeds from dispositions)	**4,767**	1,201	**53,153**	11,933
Production Volumes				
Crude oil (bbls/d)	**3,458**	1,784	**3,147**	1,834
Natural gas (Mcf/d)	**13,136**	9,733	**14,099**	8,715
Natural gas liquids (bbls/d)	**225**	134	**259**	129
Total (boe/d)	**5,872**	3,540	**5,756**	3,416
% Liquids	**63%**	54%	**59%**	57%
Average Realized Prices				
Crude oil ($/bbl)	**55.42**	47.62	**55.63**	40.43
Natural gas ($/Mcf)	**3.00**	1.37	**2.98**	1.58
Natural gas liquids ($/bbl)	**32.19**	17.22	**34.00**	14.82
Total ($/boe)	**40.58**	28.41	**39.25**	26.30
Operating Netback ($/boe)[2]				
Realized price	**40.58**	28.41	**39.25**	26.30
Royalties	**(5.63)**	(2.87)	**(5.80)**	(2.53)
Operating costs	**(18.90)**	(15.60)	**(17.98)**	(18.43)
Operating netback	**16.05**	9.94	**15.47**	5.34
Realized gains on derivative instruments	**2.15**	7.88	**1.78**	9.85
Operating netback, after realized gains on derivative instruments	**18.20**	17.82	**17.25**	15.19

2017 corporate developments:

- On March 22, 2017, PPR acquired oil and natural gas assets in the Greater Red Earth area of Northern Alberta (the "Red Earth Assets") for cash consideration of $40.9 million (the "Red Earth Acquisition"). 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. The acquisition further enhances the Company's size and competitive position through an increased liquids ratio, lower corporate decline and increased operating netbacks. In conjunction with the closing of the Red Earth Acquisition, PPR amended its credit facility to increase its borrowing capacity to $65.0 million (the "Amended Credit Facility").

- On March 16, 2017, the Company issued 5,195,000 flow-through common shares with respect to Canadian Exploration Expenses ("CEE") at $0.77 per share and 5,971,000 subscription receipts ("Subscription Receipts") at $0.67 per unit for total 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

[1,2] Adjusted funds from operations and operating netback are non-IFRS measures and are defined below under "Other Advisories".

one-half of one common share warrant (each whole warrant, a "Warrant"). Each Warrant entitles the holder to acquired one common share at an exercise price of $0.87 per share until March 16, 2019. On April 12, 2017, the over-allotment option was partially exercised, resulting in the issuance of an additional 146,170 CEE flow-through common shares at $0.77 per share and 338,650 Subscription Receipts at $0.67 per share for total gross proceeds of $0.3 million.

Year-to-date 2017 highlights include:

- Production averaged 5,756 boe/day (59% liquids), a 69% increase compared to the first half of 2016 due to production additions from the Arsenal acquisition (see "Arrangement Agreement" below), the Red Earth Acquisition and the successful 2016 and 2017 Wheatland development program which resulted in 15 wells being brought on production in 2016 and four wells being brought on production in the first six months of 2017. Production additions were partially offset by natural declines.

- Operating netback after realized hedging gains was $17.25/boe for the first half of 2017, an increase of $2.06/boe from the same period in 2016. The increase was primarily due to an increase in realized prices of $12.95/boe offset by lower realized gains on derivative instruments of $8.07/boe and higher royalties of $3.27/boe.

- Adjusted funds from operations were $13.0 million, an increase of $8.7 million as compared to $4.3 million for the corresponding period in 2016, primarily due to higher operating netbacks after realized hedging gains, higher production and lower G&A expenses.

- Capital expenditures (net of $0.3 million proceeds from dispositions) in the first six months of 2017 were $53.2 million, including $40.9 million for the Red Earth Acquisition. Excluding acquisitions and dispositions, capital expenditures were $11.7 million including $9.6 million on the Wheatland development program and $1.0 million on the Evi Waterflood project. Wheatland expenditures included the tie-in and bringing on-stream two gross wells drilled in the fourth quarter of 2016, construction of facilities and pipeline in the area, and the drilling, completion, equipping and tie-in costs of four gross wells, of which two were brought on-stream in the middle of May and at the end of June 2017, respectively, with the remaining two brought on production in July and August 2017.

- Net earnings for the first half of 2017 were $8.3 million, compared to a net loss of $40.0 million in the six months ended June 30, 2016. The $48.3 million increase in net earnings was a result of an $8.7 million increase in adjusted funds from operations (see "Other Advisories" below), and positive variances in several non-cash items, including a $25.1 million decrease in impairment, a $20.4 million increase in unrealized derivative gains, a decrease in accretion costs of $7.4 million and an increase of $3.9 million in gains on business combination, offset by a $9.8 million decrease in foreign exchange gains and an increase of $7.7 million in DD&A.

- Exited the quarter with borrowings of $47.0 million drawn on the Amended Credit Facility and a working capital deficit (as defined in "Other Advisories" below) of $7.4 million. As compared to the first quarter of 2017, the working capital deficit decreased by $5.7 million from $13.1 million at March 31, 2017 while borrowings increased by $1.5 million from $45.5 million at March 31, 2017.

Second quarter 2017 highlights include:

- Production averaged 5,872 boe/day (63% liquids), a 66% increase compared to the second quarter of 2016 due to production additions from the Arsenal acquisition, the Red Earth Acquisition and the successful Wheatland drilling program. Partially offsetting these increases were third-party facility outages at the Waterton and Wheatland areas that curtailed production by approximately 300 boe/d and extended downtime in Evi due to wet weather conditions and road bans that further impacted volumes by 190 boe/d.

- Operating netback after realized hedging gains was $18.20/boe for the second quarter of 2017, an increase of $0.38/boe from the second quarter of 2016. The increase was primarily due to higher realized prices which were substantially offset by lower realized gains on derivative instruments, higher operating costs and higher royalties.

- Adjusted funds from operations were $7.1 million, a $3.8 million increase as compared to the second quarter of 2016 primarily due to higher production and higher operating netback after realized hedging gains.

- Capital expenditures were $4.8 million, primarily directed to the Wheatland drilling program. Our second quarter capital activity levels were reduced due to the seasonal impacts of spring break up, delayed scheduling of frac crews, and a conscious decision to defer our capital spending. This resulted in reduction of our working capital deficit from the first quarter of 2017.

- Net earnings of $1.1 million, compared to a net loss of $43.2 million in the second quarter of 2016. The $44.3 million increase in net earnings was the result of a $3.8 million increase in adjusted funds from operations (as defined in "Other Advisories" below) and positive variances in several non-cash items, including a $25.2 million decrease in impairment loss, a $15.4 million increase in unrealized hedging gains and a $3.6 million decrease in accretion expense offset by a $4.2 million increase in DD&A.

Outlook

PPR has remained true to our corporate strategy, and conservatively executed our capital program while seeking to control costs and manage debt levels. During the first half of 2017, we invested approximately $17 million of our projected 2017 $25 to $35 million exploration and development budget, with continued success as our current production volumes are running close to our expected annual average. We will continue to focus on improving corporate netbacks by targeting higher value product streams (oil and condensate-rich liquids) and take steps to improve capital efficiencies through pad drilling as well as focusing on those operating areas that have underutilized infrastructure capacity.

Despite continued commodity price volatility, PPR remains focused on delivering growth through production and funds from operations while continuing to preserve its financial position. As such, PPR is targeting the lower end of previously announced 2017 guidance range, with a capital budget of approximately $25 million. We plan to defer a portion of the fourth quarter development to 2018, which will lower our forecast exit production to between 6,000 and 6,500 boe/d without significant impact to our annual production guidance. We will continue to monitor the pricing conditions and will adjust the pace of our development to protect our project economics.

PPR's hedging program provides protection for approximately 70% of our 2017 estimated base production volumes (net of royalties), and based on our 2017 forecast adjusted funds from operations, we anticipate being able to fund our capital budget without incurring additional debt.

Arrangement Agreement

On September 12, 2016, Lone Pine and Arsenal completed a business combination by way of a plan of arrangement ("Arrangement") whereby Lone Pine and Arsenal became direct or indirect wholly-owned subsidiaries of Prairie Provident Resources Inc. (see Note 1 to the Annual Financial Statements).

The acquisition of Arsenal common shares was accounted for as a business combination using the acquisition method of accounting whereby PPR was deemed to be the acquirer of the Arsenal business and the assets and liabilities assumed were recorded at their fair values. Transaction costs associated with the acquisition are expensed when incurred.

Business Combination

On March 22, 2017, PPR acquired oil and natural gas properties in the Greater Red Earth area of Northern Alberta for cash consideration of $40.9 million. 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 in the area. The Greater Red Earth asset acquired included producing assets with production at acquisition 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 with an increased borrowing base of $65 million, and through the gross proceeds from a bought-deal equity financing of $8.0 million ($7.0 million net of share issuance costs), which closed on March 16, 2017. 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 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 entitles the holder to acquire one common share at an exercise price of $0.87 per share until March 16, 2019. Pursuant to the bought-deal financing, the underwriters' had an over-allotment option to purchase, at any time prior to April 15, 2017, up to an additional 15% of the number of flow-

through common shares and Subscription Receipts initially offered. On April 12, 2017, the over-allotment option was partially exercised, resulting in the issuance of an additional 146,170 CEE flow-through common shares at $0.77 per share and 338,650 Subscription Receipts at $0.67 per share for total gross proceeds of $0.3 million ($0.3 million net of share issuance costs).

Results of Operations

Production

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	**2017**	2016
Crude oil (bbls/d)	**3,458**	1,784	**3,147**	1,834
Natural gas (Mcf/d)	**13,136**	9,733	**14,099**	8,715
Natural gas liquids (bbls/d)	**225**	134	**259**	129
Total (boe/d)	**5,872**	3,540	**5,756**	3,416
Liquids Weighting	**63%**	54%	**59%**	57%

PPR's production for the three and six months ended June 30, 2017 increased by 66% and 69%, respectively, compared to the corresponding periods in 2016. The increases were primarily the result of additions from the Arsenal acquisition, the Red Earth Acquisition and the Wheatland drilling program. The Arsenal acquisition contributed incremental production in each of the three and six months ended June 30, 2017 of approximately 1,000 boe/d. The successful drilling program at Wheatland resulted in increased production in the three and six months ended June 30, 2017 of approximately 850 boe/d and 1,200 boe/d, respectively. Production related to the Red Earth Acquisition, has been included in PPR's operating results since the closing date of the acquisition on March 22, 2017. This resulted in added production of approximately 1,000 boe/d and 550 boe/d for the three and six months ended June 30, 2017, respectively.

Partially offsetting the production increases were natural production declines, approximately 300 boe/d from third-party outages in the Waterton and Wheatland areas and approximately 190 boe/d from extended downtime primarily in the Evi area due to wet weather conditions, road bans and integration of the Red Earth assets acquired. Certain recently acquired Red Earth assets were experiencing downtime initially as they were behind their scheduled maintenance. The timing of the second quarter 2017 capital program was delayed due to the seasonal impacts of spring break up, delayed scheduling of frac crews, and a conscious decision to defer capital spending to preserve liquidity given the volatile commodity price environment in the second half of the quarter. This also resulted in slightly lower than anticipated production additions for the three and six months ended June 30, 2017.

The increase in the liquids-weighting from the three and six months ended June 30, 2017 was primarily related to the properties acquired in the Red Earth Acquisition which have a liquids weighting of approximately 98%.

Revenue

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per unit amounts)	**2017**	2016	**2017**	2016
Revenue				
Crude oil	**17,441**	7,731	**31,686**	13,496
Natural gas	**3,582**	1,210	**7,610**	2,510
Natural gas liquids	**659**	210	**1,594**	348
Oil and natural gas revenue	**21,682**	9,151	**40,890**	16,354
Average Realized Prices				
Crude oil ($/bbl)	**55.42**	47.62	**55.63**	40.43
Natural gas ($/Mcf)	**3.00**	1.37	**2.98**	1.58
Natural gas liquids ($/bbl)	**32.19**	17.22	**34.00**	14.82
Total ($/boe)	**40.58**	28.41	**39.25**	26.30
Benchmark Prices				
Crude oil - WTI ($/bbl)	**64.96**	58.78	**66.78**	52.37
Crude oil - Edmonton Light Sweet ($/bbl)	**61.54**	54.27	**62.47**	47.26
Natural gas - AECO monthly index-7A ($/Mcf)	**2.77**	1.25	**2.86**	1.67
Natural gas - AECO daily index - 5A ($/Mcf)	**2.79**	1.40	**2.74**	1.61
Exchange rate - US$/CDN$	**0.74**	0.78	**0.75**	0.75

PPR's second quarter 2017 revenue increased by 137% or $12.5 million from the second quarter of 2016. The 126% increase in crude oil revenue incorporates a 94% increase in oil production and a 16% rise in realized prices. The 196% increase in natural gas revenue was the result of a 35% increase in production and a 119% increase in realized prices. The movements in PPR's realized prices correlated with those observed in the benchmark prices. The increase in the overall average realized prices of 43% incorporated a higher liquids-weighted production mix in 2017 than in 2016.

On a year-to-date basis, revenue increased by 150% or $24.5 million, compared to the same period in 2016. The 135% increase in crude oil revenue and the 203% increase in natural gas revenue reflected higher production volumes, which rose by 72% and 62%, respectively, and increases in realized prices of crude oil and natural gas of 38% and 89%, respectively. The higher realized prices reflected the increases in benchmark prices. The increase in the overall average realized prices of 49% incorporated a slightly higher liquids-weighted production mix in the first half of 2017 than in the same period in 2016.

Royalties

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Royalties	**3,009**	924	**6,038**	1,573
Per boe	**5.63**	2.87	**5.80**	2.53
Percentage of revenue	**13.9%**	10.1%	**14.8%**	9.6%

The majority of PPR's royalties are paid to the Crown, which 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 5% and 17.5%, with average royalties rates which are higher than the average royalty rate of the remaining properties. On a percentage of revenue basis, royalties for the three and six months ended June 30, 2017 increased from the corresponding periods in 2016 due to royalties incurred on additional Wheatland production, the impact of the Arsenal properties acquired and a higher Crown royalty burden as a result of higher benchmark prices.

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 June 30,		Six Months Ended June 30,	
($000s)	**2017**	2016	**2017**	2016
Realized gain on derivatives	**1,150**	2,539	**1,853**	6,124
Unrealized gain (loss) on derivatives	**4,471**	(10,959)	**10,329**	(10,107)
Total gain (loss) on derivatives	**5,621**	(8,420)	**12,182**	(3,983)
Per boe				
Realized gain on derivatives	**2.15**	7.88	**1.78**	9.85
Unrealized gain (loss) on derivatives	**8.37**	(34.02)	**9.91**	(16.26)
Total gain (loss) on derivatives	**10.52**	(26.14)	**11.69**	(6.41)

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.

As of June 30, 2017, the Company held the following outstanding derivative contracts:

Commodity Contract	Notional Quantity	Remaining Term	Reference	Weighted Average Price		Contract Type
Oil	500 bbls/d	July 1, 2017 – December 31, 2017	CDN$ WTI	$	87.78	Swap
Oil	500 bbls/d	July 1, 2017 – December 31, 2017	CDN$ WTI	$	65.00/72.00	Collar
Oil	250 bbls/d	July 1, 2017 – December 31, 2017	CDN$ WTI	$	65.00/75.00	Collar
Oil	500 bbls/d	July 1, 2017 – December 31, 2017	CDN$ WTI	$	58.00/67.50	Collar
Oil	400 bbls/d	July 1, 2017 – December 31, 2017	CDN$ WTI	$	70.00/85.00	Collar
Light Oil [(1)] Differential	1,000 bbls/d	July 1, 2017 – December 31, 2017	CDN$ MSW	$	-5.70	Swap
Natural Gas	6,050 GJ/d	July 1, 2017 – December 31, 2017	AECO 7A Monthly Index	$	2.79	Swap
Natural Gas	800 GJ/d	October 1, 2017 – December 31, 2017	AECO 7A Monthly Index	$	2.95	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
Natural Gas	2,500 GJ/d	January 1, 2018 – March 31, 2018	AECO 7A Monthly Index	$	3.12	Swap
Natural Gas	1,500 GJ/d	January 1, 2018 – December 31, 2018	AECO 7A Monthly Index	$	2.76	Swap
Natural Gas	1,500 GJ/d	January 1, 2018 – December 31, 2018	AECO 7A Monthly Index	$	2.76	Sold Call Option
Oil	400 bbls/d	January 1, 2019 – December 31, 2019	CDN$ WTI	$	85.00	Sold Call Option
Natural Gas	2,000 GJ/d	January 1, 2019 – March 31, 2019	AECO 7A Monthly Index	$	2.73	Swap

(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 June 30,		Six Months Ended June 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Lease operating expense	**7,121**	3,286	**12,823**	8,160
Transportation and processing	**1,776**	1,310	**3,995**	2,430
Production and property taxes	**1,202**	430	**1,914**	866
Total operating expenses	**10,099**	5,026	**18,732**	11,456
Per boe	**18.90**	15.60	**17.98**	18.43

Lease operating expense for the second quarter of 2017 increased by 117% from the same period in 2016 primarily due to incremental production from Wheatland, the Arsenal assets and the Red Earth assets. Lease operating expenses for the six months ended June 30, 2017 increased by 57% from the same period in 2016. The increase was the result of the factors described above; however, it was mitigated by $1.0 million of site clean-up and remediation costs that were included in the first quarter of 2016 lease operating expenses as a result of a breach in an above-ground section of wellhead piping in the Wheatland area that occurred in the quarter. These costs were subsequently offset by a $0.9 million insurance recovery that was received in the fourth quarter of 2016.

Transportation and processing expense for the three and six months ended June 30, 2017 increased by $0.5 million and $1.6 million, respectively, as compared to the same periods in 2016. The increases primarily related to third-party natural gas processing costs and natural gas transportation costs incurred on Wheatland production.

Production and property tax expense for the three and six months ended June 30, 2017 increased by $0.8 million and $1.0 million, respectively, as compared to the same periods in 2016. The increases primarily related to properties acquired in the Arsenal acquisition and the Red Earth Acquisition.

Operating expenses on a per boe basis were $3.30 higher in the second quarter of 2017 as compared to the same period in 2016 primarily as a result of maintenance work performed in the quarter and the inclusion of the Red Earth properties that have higher operating expenses on a per boe basis. PPR incurred additional maintenance and workover expenses on the recently acquired Red Earth properties as they were behind their maintenance schedule and experiencing some outages. Wet weather conditions at Evi and Wheatland during spring break-up further contributed to increased lease operating and maintenance costs. The year-to-date 2017 operating costs were slightly lower than the year-to-date 2016 operating costs which incorporated costs related to the Wheatland wellhead pipe breach incident.

Operating Netback

	Three Months Ended June 30,		Six Months Ended June 30,	
($ per boe)	**2017**	2016	**2017**	2016
Revenue	**40.58**	28.41	**39.25**	26.30
Royalties	**(5.63)**	(2.87)	**(5.80)**	(2.53)
Operating costs	**(18.90)**	(15.60)	**(17.98)**	(18.43)
Operating netback	**16.05**	9.94	**15.47**	5.34
Realized gains on derivative instruments	**2.15**	7.88	**1.78**	9.85
Operating netback, after realized gains on derivative instruments	**18.20**	17.82	**17.25**	15.19

PPR's operating netback after realized hedging gains increased by $0.38/boe and $2.06/boe, respectively, for the three and six months ended June 30, 2017, compared to the corresponding periods in 2016. For the second quarter of 2017, increases in realized revenue were partially offset by decreases in realized gains on derivative instruments

and increases in royalties and operating costs. For the six months ended June 30, 2017, increases in realized revenue and decreases in operating costs were partially offset by decreases in realized gains on derivative instruments and increases in royalties.

General and Administrative Expenses ("G&A")

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Gross cash G&A expenses	**2,833**	2,694	**5,441**	5,681
Gross share-based compensation expense	**220**	49	**359**	143
Less amounts capitalized	**(486)**	(293)	**(973)**	(670)
Net G&A expenses	**2,567**	2,450	**4,827**	5,154
Per boe	**4.80**	7.61	**4.63**	8.29

For the three months and six months ended June 30, 2017, gross cash G&A were comparable to the same periods in 2016 notwithstanding PPR has grown its production significantly and become a public company within the last twelve months.

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 increases in gross share-based compensation expense was the result of share-based incentive awards granted to employees, officers and directors in the fourth quarter of 2016 and the first quarter of 2017. Additionally, beginning in the second quarter of 2017, share-based incentive awards are granted to non-management directors on a quarterly basis in-lieu of a portion of fees previously paid in cash.

Capitalized G&A varies with the composition and compensation levels of technical departments and their time attributed to capital projects. The increase in capitalized G&A for the three and six months ended June 30, 2017 compared to the same periods in 2016 related to the increased staffing levels in the technical departments subsequent to the Arrangement.

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. Prior to the Arrangement, share-based compensation related to restricted share units, which were settled with PPR common shares in the fourth quarter of 2016 and in the first quarter of 2017.

In the first six months of 2017, the Company granted 1,969,795 stock options to employees, officers and directors at a weighted average exercise price of $0.75 per share. Options granted vest evenly over a three-year period and will expire five years after the grant date. As at June 30, 2017, 2,721,969 stock options were outstanding, of which 250,724 were exercisable.

The Company issued 354,905 performance share units ("PSUs") to certain officers of the Company in the first six months of 2017. These PSUs will vest on December 15, 2019 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 June 30, 2017, 471,332 PSUs were outstanding.

During the year-to-date 2017 period, the Company issued 89,850 deferred restricted share units ("DSUs") to non-management directors of the Company. DSUs vest in their entirety on the grant date and will be settled when a director ceases to be a member of the board of directors. DSUs may be settled in common shares or cash at the

discretion of the Company. It is PPR's intention to settle the PSUs in common shares and the plan has accounted for as equity settled. As at June 30, 2017, there were 89,850 DSUs outstanding.

Finance Costs

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Interest expense	**525**	184	**834**	362
Accretion expenses	**553**	4,167	**1,023**	8,462
Total finance cost	**1,078**	4,351	**1,857**	8,824
Per boe	**2.02**	13.51	**1.78**	14.19

Interest expense is primarily related to interest incurred related to the Company's credit facilities. There were no borrowings outstanding during the three and six months ended June 30, 2016 and interest incurred in this period primarily comprised of the amortization of deferred financing charges, recognition of standby fees and interest on outstanding letters of credit. The increase in interest expense by $0.3 million and $0.5 million from the three and six months ended June 30, 2016 relates to borrowings under the Company's credit facilities during the 2017. The weighted average effective interest rate on credit facility borrowings for the three and six months ended June 30, 2017 was 3.7% and 3.5%, respectively (2016 – 2.0% and 2.0%, respectively, on letters of credit outstanding).

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 three and six months ended June 30, 2016, the Company recognized $3.9 and $7.9 million, respectively, of accretion charges on the preferred shares. The remaining accretion charges primarily related to the decommissioning liabilities, which increased by $0.2 million and $0.4 million, respectively, during the three and six months ended June 30, 2017 from the same periods in the prior year as a result of additional decommissioning liabilities acquired from the Arsenal acquisition and the Red Earth Acquisition.

Gain (Loss) on Foreign Exchange

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s)	**2017**	2016	**2017**	2016
Realized gain (loss) on foreign exchange	**142**	(2)	**197**	71
Unrealized gain (loss) on foreign exchange	**87**	(504)	**117**	10,071
Gain (loss) on foreign exchange	**229**	(506)	**314**	10,142

Foreign exchange gains (losses) incurred in the three and six months ended June 30, 2016 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 given period would result in unrealized foreign exchange loss (gain) on the 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 three and six months ended June 30, 2017.

Exploration and Evaluation Expense

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Exploration and evaluation expense	**58**	8	**66**	34
Per boe	**0.11**	0.02	**0.06**	0.06

Exploration and evaluation expenses are comprised of undeveloped land expiries.

Depletion and Depreciation

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Depletion and depreciation	**9,224**	5,043	**17,425**	9,701
Per boe	**17.26**	15.65	**16.73**	15.60

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 slight increase in the depletion rate for the three and six months ended June 30, 2017 from the comparable periods in 2016 incorporates the assets and related reserves acquired through the Arrangement and the Red Earth Acquisition.

Impairment Loss

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
E&E impairment	**—**	24,990	**—**	24,990
P&D inventory impairment	**—**	200	**—**	200
Inventory impairment (recovery)	**—**	—	**—**	(125)
Total impairment loss	**—**	25,190	**—**	25,065

Second quarter and year-to-date 2016 E&E impairment losses were incurred on assets in the Quebec exploratory area as a result of a shift in management development priorities.

P&D inventory impairment of $0.2 million in the second quarter and year-to-date 2016 related to the write-down of certain surplus equipment.

Capital Expenditures[1]

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s)	**2017**	2016	**2017**	2016
Drilling and completion	**2,576**	7	**7,309**	6,064
Equipment, facilities and pipelines	**1,338**	819	**2,963**	4,979
Land	**296**	31	**305**	78
Capitalized overhead and other	**557**	364	**1,096**	832
Total expenditures	**4,767**	1,221	**11,673**	11,953
Acquisitions – cash consideration	**—**	—	**41,829**	—
Proceeds from disposals of property	**—**	(20)	**(349)**	(20)
Total – net	**4,767**	1,201	**53,153**	11,933

PPR focused its capital activities during the second quarter and year-to-date 2017 in the Wheatland area including the drilling and completion of four gross (4.0 net) wells and expenditures on the construction of facilities and pipelines. Year-to-date capital expenditures also included costs incurred on the equipping and tie-in of two Wheatland wells that were drilled and completed in 2016 as well as capital expenditures on advancing the Evi waterflood project including the conversion of four producer wells to water injection wells. Additionally, in the first quarter of 2017 the Company incurred $41.8 million on acquisitions of oil and natural gas properties, of which $40.9 million was for the Red Earth Acquisition (see Business Combinations above).

In the second quarter of 2017, costs were incurred on the completion, equip and tie-in of the four wells drilled in the first quarter of 2017. As at June 30, 2017, two of the wells drilled in 2017 were on production with the remaining two wells coming on production in July and August 2017.

During the second quarter of 2016, the Company focused its capital expenditure on the equip and tie-in of three gross (2.9 net) wells that were drilled in the first quarter of 2016 in the Wheatland area. Year-to-date 2016 capital expenditures also included drilling and completion costs for the three gross (2.9 net) wells, as well as, construction of a multi-well battery and multiple pipelines at the Wheatland area. Additional capital expenditures were spent on the second phase of the Evi waterflood.

Reorganization Costs

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s)	**2017**	2016	**2017**	2016
Salary and benefits – terminations	**—**	116	**—**	382
Professional fees	**—**	—	**—**	10
Total reorganization costs	**—**	116	**—**	392

Reorganization costs are non-recurring costs associated with the Company's corporate restructuring activities. For 2016, the majority of the costs related to staff reductions.

Transaction Costs

Transaction costs incurred in the three months ended June 30, 2017 of $0.1 million related to the Red Earth Acquisition (2016 – $0.3 million related to the Arrangement) and year-to-date transaction costs of $0.8 million included $0.5 million related to the Red Earth Acquisition and $0.3 million related to the Arrangement (2016 – $0.3 million related to the Arrangement). Transaction costs were comprised primarily of legal fees and professional fees.

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

Decommissioning Liabilities

The Company's decommissioning liabilities at June 30, 2017 were $112.0 million (December 31, 2016 – $97.7 million) to provide for future remediation, abandonment and reclamation of PPR's oil and gas properties. The $14.3 million increase in decommissioning liabilities was primarily due to the Red Earth Acquisition and related change in estimates, partially offset by settlements of decommissioning obligations of $4.6 million. The Company completed the majority of its 2017 decommissioning program in the first quarter of 2017 in a winter access only area.

Decommissioning obligations acquired through business combination and asset acquisition are initially measured at fair value using a credit-adjusted risk free rate of 5.7% 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 as disclosed above resulted in an increase to the carrying values of decommissioning liabilities of $11.5 million, which was included in changes in estimates.

The undiscounted and inflated decommissioning obligation liabilities, based on an inflation rate of 1.7%, were estimated at $174.8 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.

Capital Resources and Liquidity

Capital Resources

Working Capital

At June 30, 2017, PPR had a working capital deficit (as defined in "Other Advisories" below) of $7.4 million (December 31, 2016 – $4.4 million). The increase in the working capital deficit was primarily the result of the Red Earth Acquisition for cash consideration of $40.9 million in the first quarter of 2017, resulting in a reduction of cash from $7.9 million as at December 31, 2016 to $nil as at June 30, 2017.

The working capital deficit decreased by $5.7 million from the March 31, 2017 working capital deficit of $13.1 million as PPR paid down its currently liabilities using borrowings under the credit facility and adjusted funds from operations (see "Other Advisories" below). In the second quarter, PPR decided to defer a portion of the second quarter capital program and applied the funds towards reduction of its current liabilities.

Amended Credit Facility

Under the Company's credit facility, PPR had outstanding long-term debt at June 30, 2017 of $47.0 million (December 31, 2016 – $15.0 million), net of deferred financing costs and prepaid interest of $0.4 million (December 31, 2016 – $0.5 million) and $4.7 million of letters of credit issued (December 31, 2016 – $5.4 million). Also included in long-term debt were $3.8 million of cheques issued in excess of cash balance.

On March 22, 2017, the Company amended its credit facility with a syndicate of banks. Under the Amended Credit Facility, PPR has a $55 million syndicated revolving term facility and a $10 million operating facility, both mature one year after the term-out date. On an annual basis prior to the applicable term-out date, subject to the lenders' approval, PPR may extend the term-out date by 364 days. The Company and its lending syndicate are progressing with new financing arrangements.

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 (1.7 to 1.0 as at June 30, 2017); 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 (1.1 to 1.0 as at June 30, 2017).

As at June 30, 2017, the Company was in compliance with all covenants under the Amended Credit Facility.

Shareholders' Equity

At June 30, 2017, PPR had consolidated share capital of $121.6 million (December 31, 2016 – $115.1 million) and had 115.9 million outstanding common shares. In addition, PPR had 2.7 million stock options (December 31, 2016 – 0.8 million), 0.5 million PSUs (December 31, 2016 – 0.1 million) (which will be settled subject to a performance multiplier from 0 to 2), 0.1 million DSUs, 3.2 million warrants (December 31, 2016 – nil) and zero RSUs (December 31, 2016 – 0.1 million) outstanding as at June 30, 2017.

As of the date of this MD&A, PPR has the same amount of equity instruments outstanding as at June 30, 2017.

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 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 and Liquidity

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 capital expenditures necessary for the replacement of production declines and decommissioning expenditures 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 PPR's capital structure can be accomplished through issuing common shares, issuing new debt or replacing existing debt, adjusting capital spending and acquiring or disposing of assets.

During the first quarter of 2017, PPR closed the Red Earth Acquisition for cash consideration of $40.9 million (see Business Combination). The transaction was funded through net proceeds of $7.3 million from the issuance of common shares in 2017 and borrowings under the Amended Credit Facility, which resulted in an increase in the Company's debt leverage. Though PPR has increased its debt leverage, 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 capital structure. PPR 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 Company's goal is to manage this ratio well within the financial covenants imposed on it under the Amended Credit Facility. Total debt to Adjusted EBITDAX at June 30, 2017 was 1.7 to 1.0 (2016 – 1.2 to 1.0), which was well below the financial covenant requirement of 3.0 to 1.0. 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.

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 funds from operations.

Contractual Obligations and Commitments

Contractual obligations and commitments are outlined in Note 20 of the Annual Financial Statements. There were no significant changes during the first six months of 2017 except as outlined below.

Lease Acquisition Capital Commitment

Under the lease acquisition capital commitment, the Company had committed to annual capital expenditures pursuant to the acquisition of approximately 73,500 net undeveloped acres in the Wheatland area. For the first two years of the leases (which ended on June 30, 2017), if the average WTI prices for a calendar quarter were below US$50/bbl, PPR may defer a portion of the drilling commitment from that commitment period to be allocated over the remaining term. Average WTI prices for the first two calendar quarters of the second commitment period were below US$50/bbl and the deferral option was exercised in the second quarter of 2017 to extend the remaining 2017 capital commitment to July 1, 2018. As of June 30, 2017, the Company has incurred $8.7 million (December 31, 2016 – $1.6 million) towards the remaining total lease acquisition capital commitment of $35.0 million. In the event that PPR does not incur the minimum capital expenditures by the end of a given commitment period, the shortfall may be payable to the vendor. The Company expects to fulfill the remainder of its lease acquisition capital commitment through its ongoing capital program in Wheatland. The lease acquisition capital commitment is further described in Note 20 of the Annual Financial Statements.

Flow-through Share Commitment

Pursuant to the bought deal financing which closed on March 16, 2017 and the related over-allotment option, the Company issued 5,341,170 flow-through common shares with respect to CEE at $0.77 per share. As defined by the Income Tax Act, the Company has until December 31, 2018 to incur $4.1 million of CEE costs related to this flow-through common share issuance.

During the first six months of 2017, the Company incurred a total of $3.4 million towards the $4.9 million flow-through share commitment related to the December 2016 flow-through share issuance. The lease acquisition capital commitment as described above and the flow-through share capital commitments may be fulfilled by the same exploration expenditures.

Supplemental Information

Financial – Quarterly extracted information

($000)	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Q4	2015 Q3
Oil and natural gas revenue	21,682	19,208	17,060	9,334	9,151	7,203	8,783	9,191
Royalties	(3,009)	(3,029)	(2,270)	(1,050)	(924)	(649)	(746)	(575)
Unrealized (loss) gain on Derivatives	4,471	5,858	(7,231)	(1,936)	(10,959)	852	(730)	4,118
Realized gain on derivatives	1,150	703	1,362	2,257	2,539	3,585	4,921	4,421
Revenue net of realized and unrealized gains (losses) on derivative instruments	24,294	22,740	8,921	8,605	(193)	10,991	12,228	17,155
Net earnings (loss)	1,066	7,262	(8,782)	(11,588)	(43,223)	3,197	(15,390)	(12,985)
Per share – basic [(1)]	0.01	0.07	(0.09)	(0.12)	(0.44)	0.03	(0.16)	(0.13)
Per share – diluted [(2)]	0.01	0.07	(0.09)	(0.12)	(0.44)	0.03	(0.16)	(0.13)
Adjusted funds from operations [(3)]	7,060	5,934	7,107	1,810	3,252	1,090	7,007	5,925
Per share – basic [(4)]	0.06	0.06	0.07	0.02	0.03	0.01	0.07	0.06
Per share – diluted [(5)]	0.06	0.06	0.07	0.02	0.03	0.01	0.07	0.06

[1,2,4,5] 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.

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

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 Arrangement with Arsenal, the Red Earth Acquisition 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 in several quarters 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.

Second quarter 2017 oil and natural gas revenue was the highest compared to the previous quarters as a result of the highest production volumes including a full quarter of production from the Red Earth Acquisition and added production from the Arrangement with Arsenal. The quarter also had the highest blended realized prices as a result of commodity price improvements, as well as a higher liquids weighting in the quarter compared to the previous seven quarters. Net income in the second quarter of 2017 incorporated non-cash unrealized gains of $4.5 million on derivative instruments.

First quarter 2017 oil and natural gas revenue increased, compared to the previous six quarters due to increased production volume including production from the Arrangement with Arsenal and ten days of production from the Red Earth Acquisition, as well as due to recoveries in crude oil prices from prior quarters. Net income of $7.3 million in the first quarter of 2017 was largely the result of non-cash items including a gain of $4.3 million on the Red Earth Acquisition, unrealized gains on derivative instruments of $5.9 million and a gain of $0.5 million in the disposition of non-core properties.

Oil and natural gas revenue and adjusted funds from operations increased significantly in the fourth quarter of 2016 as production significantly increased, coupled with the 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 of 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.

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”). There have been no changes in the Company's internal controls over financial reporting during the period from January 1, 2017 to June 30, 2017 that have materially affected, or are reasonably likely to materially affect the Company's internal controls over financial reporting.

Changes in Accounting Policies

The Interim Financial Statements have been prepared on a basis consistent with the accounting, estimation and valuation policies described in the Annual Financial Statements. PPR did not adopt any new accounting policies or standards during the second quarter of 2017.

There were no new or amended standards issued during the three months ended June 30, 2017 that are applicable to PPR in future periods. A description of issued accounting pronouncements that will be adopted by the Company in future periods is also included in Note 3 to the Annual Financial Statements. The Company is currently evaluating the impact of those new accounting pronouncements.

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 in the Annual MD&A and have remained unchanged during the first six months of 2017. Additional risks are provided in the "Risk Factors" section of the 2016 Annual Information Form filed on SEDAR at www.sedar.com.

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 new financing arrangements;
- 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 reach an agreement with counterparties to new financing arrangements on terms and conditions that are acceptable to the Company or at least as favorable to the Company than those of the existing credit facilities, or will improve PPR's liquidity profile;
- 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)	June 30, 2017	December 31, 2016
Current assets	16,999	17,539
Less current derivative instrument assets	(4,461)	—
Current assets excluding current derivatives instruments	12,538	17,539
Current liabilities	20,567	28,120
Less flow-through share premium	(129)	(390)
Less current derivative instrument liabilities	—	(2,311)
Less current portion of decommissioning liability	(500)	(3,500)
Current liabilities excluding current derivatives instruments and current portion of decommissioning liabilities	19,938	21,919
Working capital deficit	(7,400)	(4,380)

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 gains and losses, 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 June 30,		Six Months Ended June 30,	
($000s)	**2017**	2016	**2017**	2016
Cash flow from operating activities	**3,337**	1,908	**4,992**	2,434
Changes in non-cash working capital	**3,076**	1,043	**2,574**	(1,681)
Funds from Operations	**6,413**	2,951	**7,566**	753
Other	**(1)**	163	**61**	188
Settlement of decommissioning liabilities	**510**	(245)	**4,552**	2,742
Restructuring costs	**—**	116	**—**	392
Transaction costs	**138**	267	**815**	267
Adjusted Funds from Operations	**7,060**	3,252	**12,994**	4,342

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 June 30,		Six Months Ended June 30,	
($000s)	**2017**	2016	**2017**	2016
Net earnings (loss) before income tax	**909**	(43,223)	**8,067**	(40,026)
Add (deduct):				
Interest	**525**	184	**834**	362
Depletion and depreciation	**9,224**	5,043	**17,425**	9,701
Exploration and evaluation expense	**58**	8	**66**	34
EBITDAX	**10,716**	(37,988)	**26,392**	(29,929)
Unrealized (gain) loss on derivative Instruments	**(4,471)**	10,959	**(10,329)**	10,107
Impairment loss	**—**	25,190	**—**	25,065
Accretion	**553**	4,167	**1,023**	8,462
Loss (gain) on foreign exchange	**(229)**	506	**(314)**	(10,142)
Reorganization costs[1]	**—**	116	**—**	392
Share-based compensation	**204**	45	**328**	137
Loss (gain) on sale of properties	**—**	73	**(548)**	73
Loss (gain) on business combination	**450**	—	**(3,893)**	—
Transaction costs	**138**	267	**815**	267
Pro-forma impact of acquisition	**—**	1,543	**2,394**	2,098
Adjusted EBITDAX	**7,361**	4,878	**15,868**	6,530

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