Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three and Six Months Ended June 30, 2018

Dated: August 8, 2018

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" refers to Prairie Provident Resources Inc., as parent corporation, together with its wholly-owned subsidiaries, Prairie Provident Resources Canada Ltd., Lone Pine Resources Inc., Lone Pine Resources (Holdings) Inc., Arsenal Energy USA Inc. and Arsenal Energy Holding Ltd. 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, 2018. This MD&A is dated August 8, 2018 and should be read in conjunction with the unaudited condensed interim consolidated financial statements for the three and six months ended June 30, 2018 (the "Interim Financial Statements"), the audited consolidated financial statements of PPR as at and for the year ended December 31, 2017 (the "2017 Annual Financial Statements") and the 2017 annual MD&A (the "Annual MD&A") dated March 28, 2018. Additional information relating to PPR, including the Company's December 31, 2017 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
USD	U.S. dollars
CAD	Canadian dollars
US	United States
CDN	Canadian

Financial and Operational Highlights

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s except per unit amounts)	**2018**	2017	**2018**	2017
Financial				
Oil and natural gas revenue	**24,187**	21,682	**43,470**	40,890
Net earnings (loss)	**(15,064)**	1,066	**(26,806)**	8,328
Per share – basic	**(0.13)**	0.01	**(0.23)**	0.08
Per share – diluted	**(0.13)**	0.01	**(0.23)**	0.07
Adjusted EBITDAX (before pro-forma adjustments)[1]	**6,319**	7,361	**11,341**	13,474
Per share – basic & diluted	**0.05**	0.06	**0.10**	0.12
Adjusted Funds from Operations[2]	**4,792**	7,060	**8,674**	12,994
Per share – basic & diluted	**0.04**	0.06	**0.07**	0.12
Capital expenditures and acquisitions (net of proceeds from dispositions)	**4,754**	4,767	**19,706**	53,153
Production Volumes				
Crude oil (bbls/d)	**3,513**	3,458	**3,302**	3,147
Natural gas (Mcf/d)	**9,175**	13,136	**8,776**	14,099
Natural gas liquids (bbls/d)	**104**	225	**114**	259
Total (boe/d)	**5,146**	5,872	**4,879**	5,756
% Liquids	**70%**	63%	**70%**	59%
Average Realized Prices				
Crude oil ($/bbl)	**70.96**	55.42	**66.60**	55.63
Natural gas ($/Mcf)	**1.20**	3.00	**1.62**	2.98
Natural gas liquids ($/bbl)	**53.04**	32.19	**52.87**	34.00
Total ($/boe)	**51.65**	40.58	**49.22**	39.25
Operating Netback ($/boe)[3]				
Realized price	**51.65**	40.58	**49.22**	39.25
Royalties	**(8.15)**	(5.63)	**(7.19)**	(5.80)
Operating costs	**(19.64)**	(18.90)	**(19.86)**	(17.98)
Operating netback	**23.86**	16.05	**22.17**	15.47
Realized gains (losses) on derivative instruments	**(6.28)**	2.15	**(4.71)**	1.78
Operating netback, after realized gains on derivative instruments	**17.58**	18.20	**17.46**	17.25

Year-to-date 2018 highlights include:

- During the second quarter of 2018, PPR increased the borrowing base under its Revolving Facility (defined herein) from US$40 million to US$45 million. The expanded borrowing base reflects PPR's increased underlying reserves value and provides additional liquidity and financial flexibility.

- PPR's strategy to focus on oil and natural gas liquid opportunities successfully led to an oil and liquids production weighting of 70% for the first six months of 2018, up from 59% in the first six months of 2017. The attractive production mix positioned PPR to benefit from oil price recovery, evidenced by a favourable per boe

[1,2,3] Operating netback, adjusted EBITDAX, adjusted EBITDAX (before pro-forma adjustments) and adjusted funds from operations and working capital deficit are non-IFRS measures and are defined below under "Other Advisories".

realized price increase of 25% and an increase of 43% in operating netbacks (before realized gains on derivative instruments) to $22.17/boe compared to $15.47/boe in the first half of 2017.

- Production averaged 4,879 boe/day (70% liquids). Excluding the impact from divesting certain non-core gas weighted properties in 2017, production for the first half of 2018 decreased by 9%, compared to same period in 2017. The decrease was largely due to natural declines partially offset by production from the successful 2018 drilling program which brought on 510 boe/d of incremental production during the first six months of the year. Subsequent to the quarter, one additional well has come on production and the Company's production as of the date of this MD&A is approximately 6,000 boe/d.

- Adjusted EBITDAX (before pro-forma adjustments) was $11.3 million, a $2.2 million decrease from year-to-date 2017 primarily due to a $6.0 million decrease in realized hedging gains, partially offset by higher operating netbacks. PPR enters into commodity hedges on a portion of its proved developed production (base production). While PPR's new production and unhedged base production benefited fully from the strengthening in oil and NGL benchmark prices in 2018, the Company also realized hedging losses on its existing hedges.

- Adjusted funds from operations were $8.7 million, a decrease of $4.3 million as compared to $13.0 million for the corresponding period in 2017, primarily due to lower adjusted EBITDAX and higher finance costs as a result of higher average outstanding debt during 2018 year-to-date.

- Per boe operating netback before realized hedging gains was $22.17/boe for the first half of 2018, an increase of $6.70/boe from the same period in 2017. The increase was primarily due to an increase in realized prices of $9.97/boe, partially offset by higher per boe operating expenses and royalties. The increase in realized prices was due to a higher liquids weighting in our production mix, combined with higher oil and NGL benchmark prices. Operating expenses on a per boe basis was higher due to averaging fixed costs over lower production and higher per boe costs associated with oil production. Higher per boe royalties relates to higher benchmark oil prices.

- Capital expenditures excluding acquisitions and dispositions of $18.9 million represented approximately 70% of the Company's planned 2018 capital program and included the drilling of eight wells, six of which had been completed, tied-in and brought on production by the end of the second quarter. In the Princess area, $7.8 million was directed primarily towards the development of five Lithic Glauconite ("Glauc") wells, pipeline construction and a multi-well satellite. Three of the five wells were on production by June 30, 2018. The fourth well was completed and brought on production in July 2018. The last well has been completed and is expected to commence production in August 2018. In the Wheatland area, $7.2 million was primarily directed to the drilling, completion, equip and tie-in of three Wayne wells, all of which were on production by the end of the second quarter. In the Evi area, $3.1 million was allocated to the continued advancement of the waterflood project. Additionally, in the first quarter of 2018, PPR acquired synergistic assets in the Princess area for $0.9 million, which included approximately 50 boe/d of production.

- Net loss for the first half of 2018 was $26.8 million, compared to net earnings of $8.3 million in the six months ended June 30, 2017. The $35.1 million decrease in net earnings was a result of a $4.3 million decrease in adjusted funds from operations and negative variances in certain non-cash items, including a $24.8 million decrease in unrealized gains on derivative instruments and a $3.9 million decrease in gains on business combination.

- At June 30, 2018, PPR had borrowings of US$38.0 million drawn against the US$45 million Revolving Facility and US$16.5 million of Subordinated Notes (defined herein) plus a working capital deficit of CDN$5.2 million (US$4.0 million equivalent using the June 30, 2018 exchange rate of $1.00 USD to $1.3168 CAD).

Second quarter 2018 highlights include:

- Production averaged 5,146 boe/day (70% liquids) in the second quarter of 2018, a 12% decrease compared to the second quarter of 2017, or a decrease of 6% excluding the impact from divesting certain non-core gas weighted properties in the fourth quarter of 2017. Production decrease was largely due to natural declines partially offset by approximately 960 boe/d of production additions from the successful 2018 drilling program.

- Adjusted EBITDAX (before pro-forma adjustments) was $6.3 million, a $1.0 million decrease from second quarter of 2017 primarily due to $4.1 million decrease in realized hedging gains, partially offset by higher operating netbacks.

- Adjusted funds from operations were $4.8 million, a $2.3 million decrease as compared to the second quarter of 2017 primarily due to lower adjusted EBITDAX and higher finance costs.

- Operating netback before realized hedging gains was $23.86/boe for the second quarter of 2018, an increase of $7.81/boe from the second quarter of 2017. The increase was primarily due to higher realized prices, partially offset by higher royalties and operating costs.

- Capital expenditures were $4.8 million, primarily directed to the Princess and Wheatland drilling program.

- Net loss for the second quarter of 2018 was $15.1 million, compared to net earnings of $1.1 million in the same quarter of 2017. The $16.1 million variance was primarily the result of a $13.8 million decrease in non-cash unrealized gains on derivative financial instruments and a $4.1 million decrease in realized gains on derivative financial instruments.

Outlook

PPR is encouraged by the well performance from its successful 2018 drilling program, especially the Glauc wells at the Princess area. As disclosed in the July 30, 2018 news release, Princess-1 and Princess-4 (as defined therein) have shown strong production rates and, based on current production rates and netbacks, could achieve payout in approximately three months, delivering the strongest economics in PPR's portfolio of properties.

Corporate average daily production as of the date of this MD&A is approximately 6,000 boe/d (74% liquids), a 17% increase over average daily Q2 2018 production. PPR has completed its fifth Glauc well at Princess, which is expected to come on-stream in August. Based on current and projected production rates, Prairie Provident anticipates full-year production to be well within its 2018 guidance range of 5,200 to 5,600 boe/d. Prairie Provident's full-year 2018 capital budget remains consistent with the original guidance of $26 million. After bringing on-stream the fifth Princess well, PPR has approximately 22% of its 2018 capital budget available for further development.

As a result of accelerating a portion of its drilling program, PPR has increased its debt leverage in the second quarter of 2018 with a 2.8 times Debt to Adjusted EBITDAX ratio. Subsequent to June 30, 2018, PPR has sold certain non-core properties for $2.8 million without any impact to its borrowing capacity. Together with the strong production and quick payout from the Princess Glauc wells, the Company anticipates its debt leverage to improve for the rest of the year.

Additional details on Prairie Provident's 2018 capital program and guidance can be found on the Company's website at www.ppr.ca.

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 "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 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 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 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.

Results of Operations

Production

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	**2018**	2017
Crude oil (bbls/d)	**3,513**	3,458	**3,302**	3,147
Natural gas (Mcf/d)	**9,175**	13,136	**8,776**	14,099
Natural gas liquids (bbls/d)	**104**	225	**114**	259
Total (boe/d)	**5,146**	5,872	**4,879**	5,756
Liquids Weighting	**70%**	63%	**70%**	59%

PPR's production for the three and six months ended June 30, 2018 decreased by 12% and 15%, respectively, compared to the corresponding periods in 2017. The Company's conscious effort to focus on oil and natural gas liquids opportunities resulted in the divestitures of 400 boe/d of non-core gas weighted properties in the fourth quarter of 2017 and the development of more liquids-rich prospects. As a result, oil and liquids weighting increased to 70% for the three and six months ended June 30, 2018, compared to 63% and 59% for the same respective periods in 2017.

Excluding the impact of divestitures, average production decreased by 6% and 9% for the three and six months ended June 30, 2018, respectively. These additional decreases were the result of natural declines, offset by production additions from the successful first quarter 2018 drilling program. Five of the six wells drilled in the first quarter of 2018 came on-stream during the second quarter of 2018 with one well started production in mid-March 2018. Additional production from the six new wells averaged approximately 960 boe/d and 510 boe/d for the three and six months ended June 30, 2018, respectively. The year-to-date production decrease was partially offset by realizing a full quarter (March 31, 2017 – 10 days) of production in the first quarter of 2018 from the Red Earth Acquisition.

Subsequent to June 30, 2018, PPR disposed of certain properties with production of approximately 60 boe/d for gross cash proceeds of $2.8 million. The disposition is expected to have a neutral impact on cash flow from operating activities in future periods.

Revenue

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per unit amounts)	**2018**	2017	**2018**	2017
Revenue				
Crude oil	**22,686**	17,441	**39,802**	31,686
Natural gas	**999**	3,582	**2,577**	7,610
Natural gas liquids	**502**	659	**1,091**	1,594
Oil and natural gas revenue	**24,187**	21,682	**43,470**	40,890
Average Realized Prices				
Crude oil ($/bbl)	**70.96**	55.42	**66.60**	55.63
Natural gas ($/Mcf)	**1.20**	3.00	**1.62**	2.98
Natural gas liquids ($/bbl)	**53.04**	32.19	**52.87**	34.00
Total ($/boe)	**51.65**	40.58	**49.22**	39.25
Benchmark Prices				
Crude oil - WTI ($/bbl)	**87.67**	64.96	**83.64**	66.78
Crude oil - Edmonton Light Sweet ($/bbl)	**80.41**	61.54	**76.17**	62.47
Natural gas - AECO monthly index-7A ($/Mcf)	**0.99**	2.77	**1.42**	2.86
Natural gas - AECO daily index - 5A ($/Mcf)	**1.21**	2.79	**1.64**	2.74
Exchange rate - US$/CDN$	**0.77**	0.74	**0.78**	0.75

PPR's second quarter 2018 revenue increased by 12% or $2.5 million from the second quarter of 2017. The 30% increase in crude oil revenue incorporates a 28% rise in realized prices and a 2% increase in oil production. The 72% decrease in natural gas revenue was the result of a 60% decrease in realized prices and a 30% decrease in production. A significant portion of the decrease in gas production was due to the sale of non-core gas weighted assets in the fourth quarter of 2017.

On a year-to-date basis, revenue increased by 6% or $2.6 million, compared to the same period in 2017. The 26% increase in crude oil revenue reflected 20% increase in realized prices and 5% rise in production. The 66% decrease in natural gas revenue reflected a 38% production decrease and a 46% drop in natural gas 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 27% and 25% for the three and six months ended June 30, 2018, respectively, incorporated a higher liquids-weighted production mix in 2018 than in 2017.

Royalties

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Royalties	**3,815**	3,009	**6,352**	6,038
Per boe	**8.15**	5.63	**7.19**	5.80
Percentage of revenue	**15.8%**	13.9%	**14.6 %**	14.8%

A large portion 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. As oil and NGL prices increased in 2018, compared to 2017, Crown royalty rates also increased. On a percentage of revenue basis, royalties for the second quarter of 2018 increased from the second quarter of 2017 primarily due to higher Crown royalty burden. Royalties for the 2018 year-to-date period decreased slightly on a percentage of royalties basis due to lower Wheatland production which bears 15% - 17.5% of freehold royalty rates, partially offset by increases in Crown royalty rates.

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)	**2018**	2017	**2018**	2017
Realized (loss) gain on derivatives	**(2,943)**	1,150	**(4,155)**	1,853
Unrealized (loss) gain on derivatives	**(9,316)**	4,471	**(14,515)**	10,329
Total (loss) gain on derivatives	**(12,259)**	5,621	**(18,670)**	12,182
Per boe				
Realized (loss) gain on derivatives	**(6.28)**	2.15	**(4.71)**	1.78
Unrealized (loss) gain on derivatives	**(19.89)**	8.37	**(16.44)**	9.91
Total (loss) gain on derivatives	**(26.17)**	10.52	**(21.15)**	11.69

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.

The Company's realized prices are exposed to fluctuations in the US dollar and Canadian dollar exchange rate, which serve as natural hedges to the US dollar denominated debt. Therefore, the Company has entered into commodity hedges in US dollars to maintain such economic hedges.

As of June 30, 2018, the Company held the following outstanding derivative contracts:

Crude Oil Commodity Risk Management Contracts					
Commodity Contract	Notional Quantity	Remaining Term	Reference	Weighted Average Price	Contract Type
Oil	1,175 bbl/d	July 1, 2018 – September 30, 2018	US$ WTI	$ 56.67	Swap
Oil	1,050 bbl/d	October 1, 2018 – December 31, 2018	US$ WTI	$ 55.50	Swap
Oil	500 bbl/d	July 1, 2018 – December 31, 2018	US$ WTI	$ 65.00	Sold Call Option
Oil	800 bbl/d	July 1, 2018 – December 31, 2018	CDN$ WTI	$ 58.00/ 67.50	Collar
Oil	900 bbl/d	January 1, 2019 – March 31, 2019	US$ WTI	$ 55.68	Swap
Oil	250 bbl/d	April 1, 2019 – May 31, 2019	US$ WTI	$ 52.65	Swap
Oil	325 bbl/d	April 1, 2019 – June 30, 2019	US$ WTI	$ 52.75	Swap
Oil	500 bbl/d	July 1, 2019 – September 30, 2019	US$ WTI	$ 52.50	Swap
Oil	450 bbl/d	October 1, 2019 – December 31, 2019	US$ WTI	$ 52.00	Swap
Oil	400 bbl/d	January 1, 2019 – December 31, 2019	CDN$ WTI	$ 85.00	Sold Call Option
Oil	400 bbl/d	January 1, 2019 – December 31, 2019	US$ WTI	$ 52.50/60.00	Collar
Oil	275 bbl/d	January 1, 2019 – December 31, 2019	US$ WTI	$ 50.00/57.00	Collar
Oil	450 bbl/d	January 1, 2020 – March 31, 2020	US$ WTI	$ 51.50	Swap
Oil	425 bbl/d	April 1, 2020 – June 30, 2020	US$ WTI	$ 51.00	Swap
Oil	400 bbl/d	July 1, 2020 – September 30, 2020	US$ WTI	$ 50.75	Swap
Oil	400 bbl/d	October 1, 2020 – December 31, 2020	US$ WTI	$ 50.50	Swap
Oil	400 bbl/d	January 1, 2020 – December 31, 2020	US$ WTI	$ 60.50	Sold Call Option
Oil	175 bbl/d	January 1, 2020 – December 31, 2020	US$ WTI	$ 49.00/ 54.75	Collar

Natural Gas Commodity Risk Management Contracts					
Commodity Contract	Notional Quantity	Remaining Term	Reference	Weighted Average Price	Contract Type
Natural Gas	1,500 GJ/d	July 1, 2018 – December 31, 2018	AECO 7A Monthly Index	$ 2.76	Swap
Natural Gas	1,500 GJ/d	July 1, 2018 – December 31, 2018	AECO 7A Monthly Index	$ 2.76	Sold Call Option
Natural Gas	3,000 GJ/d	January 1, 2019 – March 31, 2019	AECO 7A Monthly Index	$ 2.73	Swap

Derivative contract counterparties have entered into inter-creditor agreements with the Company's lender to eliminate cash margin requirements.

Operating Expenses

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Lease operating expense	**7,202**	7,121	**13,291**	12,823
Transportation and processing	**1,555**	1,776	**2,689**	3,995
Production and property taxes	**422**	1,202	**1,559**	1,914
Total operating expenses	**9,199**	10,099	**17,539**	18,732
Per boe	**19.64**	18.90	**19.86**	17.98

Lease operating expense for the second quarter of 2018 increased by $0.1 million from the same period in 2017. Despite decreased average production, lease operating expense stayed relatively the same because of fixed operating costs. In addition, the majority of the production decrease was in natural gas which has lower per unit operating costs. Lease operating expenses for the six months ended June 30, 2018 increased by 4% from the same period in 2017. In addition to the factors described above, the increase in year-to-date lease operating costs was also caused by higher fuel costs and higher electricity rates.

Transportation and processing expense for the three and six months ended June 30, 2017 decreased by $0.2 million and $1.3 million, respectively, as compared to the same periods in 2017. The decreases primarily related to lower natural gas production resulting in reduced third-party natural gas processing and transportation costs.

Production and property tax expense for the three and six months ended June 30, 2018 decreased by $0.8 million and $0.4 million, respectively, as compared to the same periods in 2017. The decreases primarily related to a favourable prior period adjustment of $0.6 million recorded in the second quarter of 2018.

Operating expenses on a per boe basis were $0.74 higher in the second quarter of 2018 and $1.88 higher in the first six months of 2018 as compared to the same respective periods in 2017 as PPR's production mix shifted to liquids-weighted production that incur higher operating expense per boe, as well as averaging fixed operating costs over lower average production for the period.

Operating Netback

	Three Months Ended June 30,		Six Months Ended June 30,	
($ per boe)	**2018**	2017	**2018**	2017
Revenue	**51.65**	40.58	**49.22**	39.25
Royalties	**(8.15)**	(5.63)	**(7.19)**	(5.80)
Operating costs	**(19.64)**	(18.90)	**(19.86)**	(17.98)
Operating netback	**23.86**	16.05	**22.17**	15.47
Realized (losses) gains on derivative instruments	**(6.28)**	2.15	**(4.71)**	1.78
Operating netback, after realized gains on derivative instruments	**17.58**	18.20	**17.46**	17.25

PPR's operating netback after realized hedging gains decreased by $0.62/boe and $0.21/boe, respectively, for the three and six months ended June 30, 2018, compared to the corresponding periods in 2017. Increased realized prices in the 2018 periods were offset by higher royalties, operating costs and realized losses on derivative instruments.

General and Administrative Expenses ("G&A")

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Gross cash G&A expenses	**2,395**	2,833	**5,150**	5,441
Gross share-based compensation expense	**248**	220	**461**	359
Less amounts capitalized	**(443)**	(486)	**(1,075)**	(973)
Net G&A expenses	**2,200**	2,567	**4,536**	4,827
Per boe	**4.70**	4.80	**5.14**	4.63

For the three months and six months ended June 30, 2018, gross cash G&A were $0.4 million and $0.3 million lower compared to the same periods in 2017. The decrease is primarily related to lower profession fees incurred in 2018 than in 2017.

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. Capitalized G&A varies with the composition and compensation levels of technical departments and their time attributed to capital projects.

Share-based compensation

In the first six months of 2018, the Company granted 1,922,274 restricted share units ("RSUs") to officers and employees. RSUs vest evenly over a three-year period. As at June 30, 2018, 1,906,974 RSUs were outstanding. In addition, the Company issued 165,586 deferred 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. As at June 30, 2018, there were 369,823 DSUs outstanding.

Previously issued share-based compensation awards included options and performance share units "PSUs". Options vest evenly over a three year period and will expire five years after the grant date. PSUs were granted to certain officers of the company and vest on a date specified per the agreement, no more than three years after the grant date. Each PSU is subject to a performance multiplier ranging from 0 to 2 based on share performance relative to a select group of peers. As of June 30, 2018, there were 471,332 PSUs outstanding and 2,461,261 options with a weighted average strike price of $0.81 per share, of which 1,047,573 were exercisable at a weighted average strike price of $0.84 per share.

PSUs, DSUs and RSUs may be settled in common shares or cash at the discretion of the Company, however, it is PPR's intention to settle the share units in common shares. As such, these units have been accounted for as equity settled.

Finance Costs

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Interest expense	**1,762**	525	**3,362**	834
Accretion expenses	**568**	553	**1,132**	1,023
Total finance cost	**2,330**	1,078	**4,494**	1,857
Per boe	**4.98**	2.02	**5.09**	1.78

Interest expense is primarily comprised of interest incurred related to the Company's outstanding borrowings. The increase in interest expense of $1.2 million and $2.5 million for the three and six months ended June 30, 2018 as compared to the respective periods in 2017 related to increased average borrowings, higher effective interest rates on the Revolving Facility and Senior Notes than the previously outstanding credit facility that was settled on October 31, 2017 and higher amortization of deferred financing fees related to the new financing since October 31, 2017. Of the $1.8 million and $3.4 million of interest expense incurred in the three and six months ended June 30, 2018, $0.3 million and $0.7 million, respectively, was deferred and will be repaid upon maturity of the Senior Notes (see Subordinated Senior Notes section below). The weighted average effective interest rate for the three and six months ended June 30, 2018 was 8.9% and 8.8%, respectively (2017 – 3.7% and 3.5% respectively).

Accretion charges are non-cash expenses and primarily relate to the decommissioning liabilities. Accretion remained consistent in first three and six months of 2018 as compared to the same periods in 2017.

Gain (Loss) on Foreign Exchange

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s)	**2018**	2017	**2018**	2017
Realized (loss) gain on foreign exchange	**(184)**	142	**(385)**	197
Unrealized (loss) gain on foreign exchange	**(1,279)**	87	**(2,631)**	117
(Loss) gain on foreign exchange	**(1,463)**	229	**(3,016)**	314

Foreign exchange (losses) gains incurred in the three and six months ended June 30, 2018 related largely to borrowings denominated in US dollars (see "Capital Resources and Liquidity" section below). There was no US dollar denominated borrowings in the first six months of 2017.

Exploration and Evaluation Expense

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Exploration and evaluation expense	**99**	58	**246**	66
Per boe	**0.21**	0.11	**0.28**	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)	**2018**	2017	**2018**	2017
Depletion and depreciation	**8,259**	9,224	**15,675**	17,425
Per boe	**17.64**	17.26	**17.75**	16.73

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, 2018 from the comparable periods in 2017 reflects the assets and associated reserves acquired through the Red Earth Acquisition, as well as changes in assumptions used in the Company's independent annual reserves evaluation, partially offset by decreases in carrying values of the asset base as a result of impairment charges recognized in the fourth quarter of 2017.

Impairment Loss

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s)	**2018**	2017	**2018**	2017
P&D Impairment – decommissioning asset	**(162)**	—	**(162)**	—
Total impairment recovery	**(162)**	—	**(162)**	—

Second quarter and year-to-date 2018 impairment recoveries resulted from changes in estimated decommissioning liabilities of certain assets with zero carrying value.

Capital Expenditures[1]

	Three Months Ended June 30,		Six Months Ended June 30,	
($000s)	**2018**	2017	**2018**	2017
Drilling and completion	**2,256**	2,576	**11,760**	7,309
Equipment, facilities and pipelines	**1,968**	1,338	**5,382**	2,963
Land	**118**	296	**613**	305
Capitalized overhead and other	**459**	557	**1,111**	1,096
Total expenditures	**4,801**	4,767	**18,866**	11,673
Acquisitions – cash consideration	**—**	—	**887**	41,829
Proceeds from disposals of property	**(47)**	—	**(47)**	(349)
Total – net	**4,754**	4,767	**19,706**	53,153

PPR focused its capital activities during the second quarter of 2018 in the Princess and Wheatland areas. The expenditures incurred in the Princess area including the drilling of two gross (2.0 net) wells, finalizing the completion and the tie-in of three gross (3.0 net) wells that were drilled in the first quarter of 2018 and construction of a multi-well satellite and pipelines. One of the Princess wells came on production in mid-March and two of the Princess wells came on production in early May. In July 2018 an additional well was completed and started production. The remaining well is expected to come on production in August 2018. In the Wheatland area, the Company finalized the completion and tie-in of the last one of the three gross (3.0 net) wells drilled in the first quarter of 2018. Of the three wells drilled at Wheatland, two commenced production in early April and one started in June 2018.

PPR's year-to-date 2018 capital activities included drilling two gross (2.0 net) wells in Princess, drilling, completion, equip and tie-in of three (3.0 net) gross wells in Princess and three gross (3.0 net) wells in Wheatland, construction of pipelines and a multi-well satellite in Princess and the expansion of the Evi waterflood project with the conversion of three producing wells into injector wells. Year-to-date capital expenditures also include $0.9 million for the acquisition of oil and natural gas properties and infrastructure in the Princess area in the first quarter of 2018.

PPR focused its capital activities during the second quarter of 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 2017 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).

Decommissioning Liabilities

The Company's decommissioning liabilities at June 30, 2018 were $110.4 million (December 31, 2017 - $112.8 million) to provide for future remediation, abandonment and reclamation of PPR's oil and gas properties.

During the six months ended June 30, 2017, the Company recognized a decrease of $3.2 million due to changes in estimates, primarily related to a reduction in cost estimates due to the costs of abandonment work performed coming in lower than previously estimated.

Changes in estimates result 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 or recovery.

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

The Company has estimated the undiscounted total future liabilities of approximately $167.9 million spanning over the next 55 years, based on an inflation rate of 1.7% (December 31, 2017 – $171.5 million). Of the estimated undiscounted total future liabilities, approximately $10.0 million is estimated to be settled over the next five years primarily for regulatory compliance. The Company has successfully achieved cost savings through economy of scale by managing its decommissioning activities on an area or project basis. As such, the Company may elect to spend more than the regulatory requirements to capture the economic benefits.

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, 2018, PPR had a working capital deficit (as defined in "Other Advisories" below) of $5.2 million (December 31, 2017 – $2.2 million). The increase in the working capital deficit was primarily the result of accelerated capital expenditures in the six months of 2018 including the $0.9 million acquisition of properties in the Princess area.

The working capital deficit decreased by $5.7 million from March 31, 2018 as PPR paid down its currently liabilities using adjusted funds from operations and borrowings under the credit facility.

Revolving Facility

On June 21, 2018, PPR amended the borrowing base under its senior secured revolving note facility ("Revolving Facility"). The amended Revolving Facility provides a borrowing base of US$45 million (CDN$59.3 million equivalent using the June 30, 2018 exchange rate of $1.00 USD to $1.3168 CAD), an increase of US$5 million from the original agreement. The Company can make further draws on the facility on or before October 31, 2019. The Revolving Facility is denominated in USD, but accommodates CAD advances up to the lesser of CDN$18 million or US$10 million. As at June 30, 2018, the Company has drawn US$28.0 million (CDN$36.9 million equivalent using the June 30, 2018 exchange rate) of USD denominated notes and CDN$12.9 million of CAD denominated notes under the Revolving Facility. All notes were issued at par by PPR Canada and are guaranteed by Prairie Provident Resources Inc. and certain of its other subsidiaries and secured by a US$200 million debenture.

The determination of the borrowing base is made by the lenders, in their sole discretion, taking into consideration the estimated value of PPR's oil and natural gas properties in accordance with the lenders' customary practices for oil and gas loans. The borrowing base is subject to a semi-annual redetermination, with the next redetermination scheduled for November 2018.

Amounts borrowed under the Revolving Facility can be drawn in the form of USD or CAD prime advances bearing interest based on reference bank USD and CAD prime lending rates announced from time to time, or LIBOR advances (in the case of USD amounts) or CDOR advances (in the case of CAD amounts) bearing interest based on LIBOR and CDOR rates in effect from time to time, plus an applicable margin. Applicable margins per annum are as follows:

(i) for CDOR advances and CAD prime advances, the margins are between 350 and 500 basis points ("bps");

(ii) for LIBOR advances and USD prime advances, the margins range from 325 to 475 bps; and

(iii) standby fees on any undrawn borrowing capacity are between 50 to 87.5 bps per annum.

As at June 30, 2018, PPR had outstanding letters of credit of $4.8 million. The letters of credit are issued by a financial institution at which PPR has a $4.9 million cash deposit to cover letters of credit. The related deposit is classified as restricted cash on the statement of financial position and the balance is invested in short-term market deposits with maturity dates of one year or less when purchased.

As at June 30, 2018, $1.7 million of deferred costs related to the Revolving Facility was netted against its carrying value (December 31, 2017 – $2.0 million).

Subordinate Senior Notes

On October 31, 2017, the Company obtained four-year US$16 million (CDN $21.1 million using the exchange rate of $1.00 USD to $1.3168 CAD) subordinated senior notes ("Senior Notes") with a maturity date of October 31, 2021. They bear interest at 15% per annum, payable quarterly in arrears with up to 5% per annum deferrable at the election of PPR. The amount of any such deferred payment will become additional principal owing in respect of the Senior Notes payable at the maturity date. The terms of the Revolving Facility require that PPR Canada make the maximum deferred payment election. At June 30, 2018, total deferred payment was US$0.5 million (December 31, 2017 – US$0.1 million). In conjunction with the Senior Notes, the Company issued 2,318,000 warrants with an exercise price of $0.549 per share with a five-year term expiring October 31, 2022. The warrants issued were classified as a financial liability due to a cashless exercise provision and will be measured at fair value upon issuance and at each subsequent reporting period, with the changes in fair value recorded in the consolidated statement of income (loss). The fair value of these warrants is determined using the Black-Scholes option pricing model. The value of the warrant liability as at June 30, 2018 was $0.4 million (December 31, 2017 – $0.5 million).

As at June 30, 2018, $0.9 million of deferred costs related to PPR's Senior Notes was netted against its carrying value (December 31, 2017 – $0.9 million).

Covenants

The note purchase agreement for the Revolving Facility, the subordinated Senior Note agreement and related parent and subsidiary guarantees contain various covenants on the part of the Company and its subsidiaries including 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 note purchase agreement for the Revolving Facility and the subordinated Senior Note purchase agreement include the same financial covenants, with less restrictive thresholds under the subordinated Senior Note agreement for certain covenants. The financial covenants are as follows:

Financial Covenant	Revolving Facility Requirement	Senior Note Requirement	As at June 30, 2018
Total Leverage – adjusted Indebtedness to EBITDAX (as defined below) for the four quarters most recently ended	Cannot Exceed 3.5 to 1.0	Cannot Exceed 3.75 to 1.00	2.8 to 1.0
Senior Leverage – senior adjusted indebtedness to EBITDAX (as defined below) for the four quarters most recently ended	Cannot Exceed 3.0 to 1.0	Cannot Exceed 3.25 to 1.0	2.8 to 1.0
Asset Coverage – adjusted net present value of estimated future net revenue from proved reserves (discounted at 10% per annum) to adjusted indebtedness as of the date of any reserves report	Cannot be less than 1.3 to 1.0	Cannot be less than 1.3 to 1.0	2.1 to 1.0
Current ratio – consolidated current assets, plus any undrawn capacity under the Revolving Facility, to consolidated liabilities at the end of the quarter[1]	Cannot be less than 1.0 to 1.0	Cannot be less than 0.85 to 1.0	1.2 to 1.0

[1] Under the agreements, current assets exclude derivative assets while current liabilities excludes the current portion of long-term debt, the decommissioning obligations, derivative liabilities and non-cash liabilities.

The Company was in compliance with all covenants as at June 30, 2018.

Shareholders' Equity

At June 30, 2018, PPR had consolidated share capital of $121.5 million (December 31, 2017 – $121.5 million) and had 115.9 million outstanding common shares. In addition, PPR had various long-term incentive awards outstanding, as outlined in the "Share-Based Compensation" section.

On November 28, 2017, the Toronto Stock Exchange ("TSX") accepted the Company's notice to make a normal course issuer bid ("NCIB") to purchase its outstanding common shares on the open market. The TSX authorized the Company to purchase up to 4,900,000 common shares during the period from December 1, 2017 to November 30, 2018. Shares purchased under the bid will be cancelled. Transactions under the NCIB will depend on future market conditions. Prairie Provident retains discretion whether to make purchases under the NCIB, and to determine the timing, amount and acceptable price of any such purchases, subject at all times to applicable TSX and other regulatory requirements. During the first six months of 2018, the Company purchased and cancelled 57,000 shares under the NCIB at a weighted average cost of $0.43 per share.

As of the date of this MD&A, PPR has the same amount of equity instruments outstanding as at June 30, 2018.

Capital Management and Liquidity

PPR's objectives when managing capital are 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 available borrowing under outstanding debt agreements and working capital. PPR intends 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 its current and forecasted capital structure and makes adjustments on an ongoing basis in order to maintain the liquidity needed to satisfy its funding requirements. 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.

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 within the financial covenants imposed on it under its outstanding debt agreements. Total debt to Adjusted EBITDAX at June 30, 2018 was 2.8 to 1.0 (December 31, 2017 – 2.0 to 1.0) as a result of accelerating a portion of its 2018 drilling program.

During the first quarter of 2018, PPR's capital spending outpaced its cash flows from operations as the Company completed over 50% of its planned 2018 capital program so to take advantage of oil price recovery and to gear up the Company for growth. This resulted in an increase in PPR's working capital deficit and total debt to Adjusted EBITDAX ratio during this period. During the second quarter of 2018, PPR paid down current liabilities using adjusted funds from operations and borrowings under the credit facility, resulting in decreased working capital deficit by $5.7 million. Also during the second quarter of 2018, PPR has increased its Revolving Facility borrowing base by US$5 million, enhancing its access to capital resources.

Subsequent to June 30, 2018, PPR sold certain non-core properties for $2.8 million with no impact to its borrowing capacity and neutral impact on future cash flows from operating activities. The funds received will be used to pay down liabilities. Together with the strong production and potentially quick payout from the Princess Glauc wells, the Company anticipates its debt leverage to improve for the rest of the year.

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 adjusted 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 2018 except as outlined below.

Lease Acquisition Capital Commitment

Under the lease acquisition capital commitment, the Company has committed to capital expenditures of $45 million by March 31, 2019 pursuant to the acquisition of undeveloped land in the Wheatland area.

As of June 30, 2018, the Company has incurred a total of $28.1 million towards the total capital commitment of $45.0 million. Under the amending agreement, the lease term and capital commitment may be further extended to September 30, 2019, should PPR incur at least $37.5 million of the $45.0 million total commitment by March 31, 2019. PPR expects to fulfill the remaining capital commitment through its capital program at the Wheatland area.

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.

As at June 30, 2018, the Company incurred a total of $1.3 million towards the flow-through share commitment. The lease acquisition capital commitment as described above and the flow-through share capital commitment may be fulfilled by the same exploration expenditures.

Supplemental Information

Financial – Quarterly extracted information

($000)	2018 Q2	2018 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3
Oil and natural gas revenue	24,187	19,283	20,510	17,611	21,682	19,208	17,060	9,334
Royalties	(3,815)	(2,537)	(2,171)	(2,164)	(3,009)	(3,029)	(2,270)	(1,050)
Unrealized (loss) gain on derivatives	(9,316)	(5,199)	(6,960)	(2,586)	4,471	5,858	(7,231)	(1,936)
Realized (loss) gain on derivatives	(2,943)	(1,212)	851	2,222	1,150	703	1,362	2,257
Revenue net of realized and unrealized (losses) gains on derivative instruments	8,113	10,335	12,230	15,083	24,294	22,740	8,921	8,605
Net (loss) earnings	(15,064)	(11,742)	(44,145)	(11,985)	1,066	7,262	(8,782)	(11,588)
Per share – basic & diluted[1]	(0.13)	(0.10)	(0.38)	(0.10)	0.01	0.07	(0.09)	(0.12)
Adjusted funds from operations [2]	4,792	3,882	5,545	4,536	7,060	5,934	7,107	1,810
Per share – basic & diluted [3]	0.04	0.03	0.05	0.04	0.06	0.06	0.07	0.02

1,3 On September 12, 2016 by way of a plan of arrangement (the "Arrangement") and brought Lone Pine Resources Canada Ltd., Lone Pine Resources Inc. and Arsenal Energy Inc. under a common parent corporation, PPR. As the historical financial statements prior the Arrangement were prepared on a combined and consolidated basis and as such, it is not possible to measure per share amounts until subsequent to the closing of the Arrangement. The Company calculated per share information for the 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 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 has fluctuated primarily due to changes in production and movement in commodity prices. The Company's production has varied due to its capital development program at Wheatland and Princess, 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 gains on derivatives, even though significant swings in unrealized gains/losses on derivatives occurred. 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 US denominated preferred shares until they were exchanged for common shares on September 12, 2016 pursuant to the Arrangement with Arsenal and related to the US denominated borrowings after October 31, 2017. As the preferred shares were exchanged for PPR common shares on September 12, 2016, accretion expense decreased considerably in the fourth quarter of 2016 and thereafter.

Second quarter 2018 oil and natural gas revenue increased from the prior quarter due to higher production and higher realized oil prices. Realized losses on derivatives incurred in the second quarter of 2018 and the first quarter of 2018 were attributed to the continued strengthening in oil prices, as contrasted with realized gains in the fourth quarter of 2017. The net loss of $15.1 million incurred in the second quarter of 2018 relates to non-cash items including $9.3 million of unrealized losses on derivatives instruments and $8.3 million of depletion and depreciation expense.

First quarter 2018 oil and natural gas revenue declined from the prior quarter due to lower production, partially offset by increase in realized oil and NGL prices. The first quarter of 2018 net loss of $11.7 million was attributable to non-cash items including $5.2 million of unrealized losses on derivative instruments and $7.4 million of depletion and depreciation expense.

Fourth quarter 2017 oil and natural gas revenue increased from the prior quarter due to higher realized prices and a higher liquids ratio partially offset by lower production volumes. The fourth quarter 2017 net loss of $44.1 million was attributable to non-cash items including $30.8 million of impairment losses, $7.0 million of unrealized losses on derivative instruments, $8.8 million of depletion and depreciation expense and $3.7 million of E&E expense.

Third quarter 2017 oil and natural gas revenue was below the peak that occurred in the second quarter of 2017 due to commodity price declines resulting in lower blended realized prices and lower production volumes. The third quarter net loss of $12.0 million was attributable to non-cash items including $3.4 million of impairment losses, $2.6 million of unrealized losses on derivative instruments and $8.6 million of depletion and depreciation expense.

Second quarter 2017 oil and natural gas revenue was a record compared to the previous six quarters due to the Company generating its highest production volumes which included a full quarter of production from the Red Earth Acquisition and incremental volumes from the Arrangement with Arsenal. The quarter also had the highest blended realized prices due to strengthening commodity prices, as well as a higher liquids weighting in the quarter compared to the previous six quarters and relative to the quarter immediately following. 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 higher production volumes which included production from the Arrangement with Arsenal and ten days of production from the Red Earth Acquisition, as well as stronger crude oil prices compared to 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 stemming from significant production increases, coupled with the recovery of commodity prices over 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.

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, 2018 to June 30, 2018 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 other than changes in accounting policies effective January 1, 2018 described below related to the adoption of new accounting pronouncements.

Effective January 1, 2018, PPR adopted IFRS 9 – Financial Instruments replacing IAS 39 – Financial Instruments: Recognition and Measurement and IFRS 15 – Revenue from Contracts with Customers, replacing IAS 11 – Construction Contracts, IAS 18 – Revenue and several revenue-related interpretations. The adoption of these standards did not have a material impact on the Company's consolidated financial statements. Further information on the changes to accounting policies can be found in Note 3 to the Interim Financial Statements.

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

- 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. The Company intends to adopt IFRS 16 on January 1, 2019 and is in the process of identifying and reviewing contracts that fall within the scope of the new standard. The extent of the impact on the adoption of the standard has not yet been determined.

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 2018. Additional risks are provided in the "Risk Factors" section of the 2017 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 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, the warrant liability 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 and the warrant liability are excluded as they are non-monetary liabilities.

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

($000s)	June 30, 2018	December 31, 2017
Current assets	19,539	19,588
Less current derivative instrument assets	(510)	895
Current assets excluding current derivatives instruments	19,029	18,693
Current liabilities	40,441	28,594
Less flow-through share premium	(542)	(711)
Less current derivative instrument liabilities	(12,929)	(4,156)
Less current portion of decommissioning liability	(2,300)	(2,300)
Less warrant liability	(394)	(533
Current liabilities excluding current derivatives instruments, current portion of decommissioning liabilities, flow-through share premium and warrant liability	24,276	20,894
Working capital deficit	(5,247)	(2,201)

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 June 30,		Six Months Ended June 30,	
($000s)	2018	2017	2018	2017
Net cash from operating activities	4,027	3,337	7,402	4,992
Changes in non-cash working capital	534	3,076	143	2,574
Funds from Operations	4,561	6,413	7,545	7,566
Other	18	(1)	37	61
Settlement of decommissioning liabilities	167	510	827	4,552
Restructuring costs	—	—	187	—
Transaction costs	46	138	78	815
Adjusted Funds from Operations	4,792	7,060	8,674	12,994

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 outstanding debt agreements (for the periods prior to October 31, 2017, Amended Credit Facility). "Adjusted EBITDAX" corresponds to defined terms in the Company's debt agreements 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 ("pro-forma adjustments"). As transaction costs related to business combinations 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 long-term debt, Adjusted EBITDAX is determined using financial information from the most recent four consecutive fiscal quarters. Adjusted EBITDAX (before pro-forma adjustments) is determined by subtracting pro-forma adjustments from Adjusted EBITDAX.

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)	**2018**	2017	**2018**	2017
Net earnings (loss) before income tax	**(15,205)**	909	**(26,975)**	8,067
Add (deduct):				
Interest	**1,762**	525	**3,362**	834
Depletion and depreciation	**8,259**	9,224	**15,675**	17,425
Exploration and evaluation expense	**99**	58	**246**	66
EBITDAX	**(5,085)**	10,716	**(7,692)**	26,392
Unrealized (gain) loss on derivative Instruments	**9,316**	(4,471)	**14,515**	(10,329)
Impairment loss	**(162)**	—	**(162)**	—
Accretion	**568**	553	**1,132**	1,023
Loss (gain) on foreign exchange	**1,463**	(229)	**3,016**	(314)
Reorganization costs[1]	**—**	—	**187**	—
Share-based compensation	**199**	204	**363**	328
Loss (gain) on sale of properties	**(47)**	—	**(47)**	(548)
Loss (gain) on business combination	**—**	450	**—**	(3,893)
Gain on warrant liability	**(69)**	—	**(139)**	—
Transaction costs	**46**	138	**78**	815
Adjusted EBITDAX before pro-forma adjustments	**6,229**	7,361	**11,251**	13,474
Pro-forma impact of acquisition	**90**	—	**90**	2,394
Adjusted EBITDAX	**6,319**	7,361	**11,341**	15,868

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