Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three Months Ended March 31, 2018

Dated: May 9, 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 months ended March 31, 2018. This MD&A is dated May 9, 2018 and should be read in conjunction with the unaudited condensed interim consolidated financial statements for the three months ended March 31, 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"). 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.

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 March 31	
($000s except per unit amounts)	**2018**	2017
Financial		
Oil and natural gas revenue	**19,283**	19,208
Net (loss) earnings	**(11,742)**	7,262
Per share – basic & diluted	**(0.10)**	0.07
Adjusted EBITDAX (before pro-forma adjustments)[1]	**5,022**	6,113
Per share – basic & diluted	**0.04**	0.05
Adjusted funds from operations[2]	**3,882**	5,934
Per share – basic & diluted	**0.03**	0.06
Net capital expenditures	**14,952**	48,386
Production Volumes		
Crude oil (bbl/d)	**3,089**	2,832
Natural gas (Mcf/d)	**8,373**	15,073
Natural gas liquids (bbl/d)	**124**	293
Total (boe/d)	**4,609**	5,637
% Liquids	**70%**	55%
Average Realized Prices		
Crude oil ($/bbl)	**61.57**	55.89
Natural gas ($/Mcf)	**2.09**	2.97
Natural gas liquids ($/bbl)	**52.78**	35.46
Total ($/boe)	**46.49**	37.86
Operating Netback ($/boe)[3]		
Realized price	**46.49**	37.86
Royalties	**(6.12)**	(5.97)
Operating costs	**(20.11)**	(17.02)
Operating netback	**20.26**	14.87
Realized (loss) gains on derivative instruments	**(2.92)**	1.38
Operating netback, after realized (loss) gains on derivative instruments	**17.34**	16.25

First quarter 2018 highlights:

- PPR's strategy to focus on oil and natural gas liquids opportunities successfully led to an oil and liquids production weighting of 70% for the first quarter, a significant increase from 55% in the same period of the prior year. The attractive production mix positioned PPR to benefit from oil price recovery, evidenced by a favorable per boe realized price increase of 23% and a 36% increase in operating netbacks (before realized gains on derivative instruments) to $20.26/boe compared to $14.87/boe in the first quarter of 2017.

- Production averaged 4,609 boe/day (70% liquids) for the first quarter of 2018. The Company executed its spring 2018 drilling program with 100% success rate during the quarter, which was primarily directed to oil and

[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".

natural gas liquids targets. The Company brought on production one of the six wells drilled prior to the spring break-up in mid-March. Subsequent to the quarter, another four wells came on-stream increasing production to 5,200 boe/d on the date of this MD&A. The Company expects the last well to commence production in June 2018.

- Excluding the impact of divestitures of certain non-core gas weighted properties during 2017, average production decreased by approximately 11% over the same period in 2017, primarily attributable to natural declines and partially offset by realizing a full quarter of production from the acquisition of assets in the Greater Red Earth area (the "Red Earth Acquisition").

- Adjusted EBITDAX (before pro-forma adjustments) was $5.0 million, a $1.0 million decrease from the first quarter of 2017 primarily due to $1.9 million decrease in realized hedging gains, offset by higher operating netbacks.

- Adjusted funds from operations was $3.9 million, a $2.1 million decrease as compared to the first quarter of 2017 primarily due to lower adjusted EBITDAX and higher finance costs as a result of higher average outstanding debt during the first quarter 2018.

- Per boe operating netback before realized loss on derivatives was $20.26/boe for the first quarter of 2018, an increase of $5.39/boe from the first quarter of 2017. The increase was primarily due to an increase of $8.63/boe in realized prices, partially offset by higher per boe operating expenses. The increase in realized prices was due to 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. Operating netback totaled $8.4 million, an increase of $0.9 million from the same quarter in 2017.

- Capital expenditures before acquisitions totaled $14.1 million, represented over 50% of the Company's planned 2018 capital program and included the drilling of six wells during the quarter. In the Princess area, $4.5 million was directed primarily to the drilling and completion of three wells and pipeline construction, with one coming on production in mid-March. In the Wayne area, $6.0 million was primarily directed to the drilling and completion of three wells, two of which were equipped and tied-in. In the Evi area, $2.9 million was allocated to the continued advancement of the waterflood project, where three additional producing wells were converted into injector wells. In the first quarter of 2017, the Company acquired synergistic assets in the Princess area for $0.9 million, including 50 boe/d of production.

- Net loss was $11.7 million compared to net earnings of $7.3 million in the first quarter of 2017. The $19.0 million variance was largely due to an increase in unrealized losses on derivative instruments of $11.1 million, an increase in realized losses on derivative instruments of $1.9 million, an increase in foreign exchange losses of $1.6 million and an increase of finance costs of $1.4 million. Further attributing to the variance was a $4.3 million gain on business combination that was recognized in the first quarter of 2017.

- At March 31, 2018, PPR had borrowings of US$33.5 million drawn against the US$40 million Revolving Facility (defined herein) and US$16 million on its Subordinated Notes (defined herein) plus a working capital deficit of $10.9 million.

Outlook

PPR is encouraged by early production data from the six new wells. PPR anticipates spending approximately $12 million in the second and third quarters of 2018 on the continued development of its Wayne and Princess properties and further expansion of the attractive waterflood at Evi and oil development at Red Earth.

Prairie Provident's full-year 2018 guidance estimates remain unchanged from those presented in the Company's release dated March 28, 2018. 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 March 31	
	2018	2017
Crude oil (bbl/d)	**3,089**	2,832
Natural gas (Mcf/d)	**8,373**	15,073
Natural gas liquids (bbl/d)	**124**	293
Total (boe/d)	**4,609**	5,637
Liquids Weighting	**70%**	55%

PPR's production for the first quarter of 2018 averaged 4,609 boe/d. 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 increasing to 70% for the quarter, compared to 55% for the same period in 2017. Excluding the impact from divestures, average production decreased by approximately 11% over the same period in 2017, due to natural declines. The 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. The successful first quarter 2018 drilling program had a minimal impact on production in the period as one of the six wells came on production in mid-March.

Revenue

	Three Months Ended March 31	
($000s, except per unit amounts)	**2018**	2017
Revenue		
Crude oil	**17,116**	14,245
Natural gas	**1,578**	4,028
Natural gas liquids	**589**	935
Oil and natural gas revenue	**19,283**	19,208
Average Realized Prices		
Crude oil ($/bbl)	**61.57**	55.89
Natural gas ($/Mcf)	**2.09**	2.97
Natural gas liquids ($/bbl)	**52.78**	35.46
Total ($/boe)	**46.49**	37.86
Benchmark Prices		
Crude oil - WTI ($/bbl)	**79.57**	68.62
Crude oil - Edmonton Light Sweet ($/bbl)	**71.89**	63.41
Natural gas - AECO month index-7A ($/Mcf)	**1.85**	2.95
Natural gas - AECO daily index-5A ($/Mcf)	**2.08**	2.70
Exchange rate - US$/CDN$	**0.79**	0.76

PPR's first quarter 2018 revenue increased by $0.1 million from the first quarter of 2017. The 20% increase in crude oil revenue resulted from a 10% increase in realized oil prices and a 9% increase in oil production. The 61% decrease in natural gas revenue was the result of a 44% decrease in natural gas production and a 30% decrease in realized natural gas prices. PPR's realized product prices generally correlate to changes in the benchmark prices. PPR's per boe realized price increased by 23%, reflecting a higher liquids-weighted production mix in the first quarter 2018 compared to the first quarter of 2017.

Royalties

	Three Months Ended March 31	
($000s, except per boe)	**2018**	2017
Royalties	**2,537**	3,029
Per boe	**6.12**	5.97
Percentage of revenue	**13.2%**	15.8%

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%, which is currently higher than the average royalty rate of the remaining properties. On a percentage of revenue basis, royalties for the three months ended March 31, 2018 decreased from the corresponding period in 2017 due to lower production in the Wheatland area, partially offset by a higher Crown royalty burden as a result of higher benchmark crude oil 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 March 31	
($000s)	**2018**	2017
Realized (loss) gain on derivatives	**(1,212)**	703
Unrealized (loss) gain on derivatives	**(5,199)**	5,858
Total (loss) gain on derivatives	**(6,411)**	6,561
Per boe		
Realized (loss) gain on derivatives	**(2.92)**	1.38
Unrealized (loss) gain on derivatives	**(12.53)**	11.55
Total (loss) gain on derivatives	**(15.45)**	12.93

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 at March 31, 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	1,300 bbl/d	April 1, 2018 – June 30, 2018	US$ WTI	$ 57.76	Swap
Oil	1,175 bbl/d	July 1, 2018 – September 30, 2018	US$ WTI	$ 56.67	Swap
Oil	1,150 bbl/d	October 1, 2018 – December 31, 2018	US$ WTI	$ 55.50	Swap
Oil	500 bbl/d	April 1, 2018 – December 31, 2018	US$ WTI	$ 65.00	Sold Call Option
Oil	800 bbl/d	April 1, 2018 – December 31, 2018	CDN$ WTI	$ 58.00/ 67.50	Collar
Oil	600 bbl/d	January 1, 2019 – March 31, 2019	US$ WTI	$ 53.53	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	April 1, 2018 – December 31, 2018	AECO 7A Monthly Index	$ 2.76	Swap
Natural Gas	1,500 GJ/d	April 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.

Subsequent to March 31, 2018, the Company entered into the following derivative contracts:

Commodity Contract	Notional Quantity	Remaining Term	Reference	Weighted Average Price	Contract Type
Oil	300 bbl/d	January 1, 2019 – March 31, 2019	US$ WTI	$ 60.00	Swap

Operating Expenses

	Three Months Ended March 31	
($000s, except per boe)	**2018**	2017
Lease operating expense	**6,089**	5,702
Transportation and processing	**1,134**	2,219
Production and property taxes	**1,117**	712
Total operating expenses	**8,340**	8,633
Per boe	**20.11**	17.02

Lease operating expense for the first quarter of 2018 increased by 7% from the same period in 2017 primarily due to higher fuel costs and higher well maintenance activities caused by cold weather.

Transportation and processing expense for the first three months of 2018 decreased by $1.1 million as compared to the same period in 2017. The decrease was largely related to lower natural gas production resulting in reduced third-party natural gas processing and transportation costs.

On a per boe basis, operating expenses increased by 18% 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 March 31	
($ per boe)	**2018**	2017
Revenue	**46.49**	37.86
Royalties	**(6.12)**	(5.97)
Operating costs	**(20.11)**	(17.02)
Operating netback	**20.26**	14.87
Realized (losses) gains on derivative instruments	**(2.92)**	1.38
Operating netback, after realized gains/losses on derivative instruments	**17.34**	16.25

Compared against the same period in 2017, operating netback after realized gains on derivative instruments increased by $1.09/boe in the first quarter of 2018. Increased realized prices were offset by higher royalties, operating costs and realized losses on derivative instruments.

General and Administrative ("G&A") Expenses

	Three Months Ended March 31	
($000s, except per boe)	**2018**	2017
Gross cash G&A expenses	**2,755**	2,608
Gross share-based compensation expense	**213**	139
Less amounts capitalized	**(632)**	(487)
Net G&A expenses	**2,336**	2,260
Per boe	**5.63**	4.45

For the quarter ended March 31, 2018, gross cash G&A increased by $0.1 million or 6% compared to the same period 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. The increase in gross share-based compensation expense was the result of share-based incentive awards granted to employees, officers and directors in the first quarters of 2017 and 2018.

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 quarter 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 March 31, 2018, 1,922,274 RSUs were outstanding.

During the first quarter of 2018, the Company issued 72,922 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 March 31, 2018, there were 277,159 DSUs outstanding.

Previously issues 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 March 31, 2018, there were 471,332 PSUs outstanding and 2,596,969 options with a weighted average strike price of $0.81 per share, of which 1,158,047 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 March 31	
($000s, except per boe)	**2018**	2017
Interest expense	**1,600**	309
Accretion expenses	**564**	470
Total finance costs	**2,164**	779
Per boe	**5.22**	1.54

Interest expense is primarily comprised of interest incurred related to the Company's outstanding borrowings. The increase in interest expense of $1.3 million for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017 related to increased average borrowings, higher effective interest rates on the Revolving Facility and Senior Notes than the previously outstanding credit facility which was settled on October 31, 2017 and higher amortization of deferred financing fees related to the new financing. Of the $1.6 million of interest expense incurred in the first quarter of 2018, $0.4 million 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 months ended March 31, 2018 was 8.7% (March 31, 2017 – 3.1%).

Accretion charges are non-cash expenses and primarily relate to the decommissioning liabilities. Accretion increased by $0.1 million during the first quarter of 2018 from the same period in the prior year as a result of the recognition of a full quarter of accretion on additional decommissioning liabilities acquired from the Red Earth Acquisition in the first quarter of 2017.

Loss on Foreign Exchange

	Three Months Ended March 31	
($000s)	**2018**	2017
Realized (loss) gain on foreign exchange	**(201)**	55
Unrealized (loss) gain on foreign exchange	**(1,352)**	30
(Loss) gain on foreign exchange	**(1,553)**	85

Foreign exchange (losses) gains incurred in the three months ended March 31, 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 quarter of 2017.

Exploration and Evaluation Expense

	Three Months Ended March 31	
($000s, except per boe)	**2018**	2017
Exploration and evaluation expense	**147**	8
Per boe	**0.35**	0.02

Depletion and Depreciation

	Three Months Ended March 31	
($000s, except per boe)	**2018**	2017
Depletion and depreciation	**7,416**	8,201
Per boe	**17.88**	16.17

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 increase in the depletion rate for the first quarter of 2018 from the comparable period 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.

Capital Expenditures

	Three Months Ended March 31	
($000s)	**2018**	2017
Drilling and completion	**9,504**	4,733
Equipment, facilities and pipelines	**3,414**	1,625
Land	**495**	9
Capitalized overhead and other	**652**	539
Capital expenditures	**14,065**	6,906
Acquisitions – cash consideration	**887**	41,829
Proceeds from disposals of property	**—**	(349)
Total capital expenditures and acquisitions net of dispositions	**14,952**	48,386

PPR focused its capital activities during the first quarter of 2018 in the Princess, Wheatland and Evi areas. The expenditures incurred in the Princess area including drilling and completing three gross (3.0 net) wells and pipeline construction in the area. One of the Princess wells drilled came on production in mid-March and the remaining two wells came on production in early May 2018. In the Wheatland area, the Company incurred costs related to the drilling and completion of three gross (3.0 net) wells and the equipping and tie-in costs for two of these wells, both of which came on production in early April. The third Wheatland well is expected to come on production in early June 2018. Additional capital expenditures in the Evi area were spent on advancing the Evi waterflood project including the conversion of three producer wells to water injection wells.

Additionally, the Company incurred $0.9 million on acquisitions of oil and natural gas properties and infrastructure in the Princess area in the first quarter of 2018.

During the first quarter of 2017, the Company focused its capital activities in the Wheatland area including the drilling 4 gross (4.0 net) wells, the equipping and tie-in of two wells that were drilled and completed in 2016 and pipelines construction in the area. Additional capital expenditures were spent on advancing the Evi waterflood project including the conversion of 4 producer wells to water injection wells. Additionally, the Company incurred $41.8 million on acquisitions of oil and natural gas properties in the first quarter of 2017, primarily for the Red Earth Acquisition (see Business Combination above).

Decommissioning Liabilities

The Company's decommissioning liabilities at March 31, 2018 were $113.4 million (December 31, 2017 - $112.8 million) to provide for future remediation, abandonment and reclamation of PPR's oil and gas properties.

The Company has estimated the undiscounted total future liabilities of approximately $172.0 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, $10.1 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 March 31, 2018, PPR had working capital deficit (as defined in "Other Advisories" below) of $10.9 million (December 31, 2017 - $2.2 million). The increase in the working capital deficit was primarily the result of capital expenditures in the first quarter of 2018 including the $0.9 million acquisition of properties in the Princess area.

Revolving Facility

On October 31, 2017, the Company entered into a US$40 million (CDN$51.6 million using the March 31, 2018 exchange rate of $1.00 USD to $1.29 CAD) borrowing base senior secured revolving note facility ("Revolving Facility") with a maturity date of October 31, 2020. 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 March 31, 2018, the Company has drawn US$23.5 million (CDN$30.3 million equivalent using the March 31, 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. On the date of this MD&A, the Revolving Facility lenders are in the routine progress of borrowing base re-determination.

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 March 31, 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 March 31, 2018, $1.9 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 $20.6 million using the exchange rate of $1.0000 USD to $1.2894 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. 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 March 31, 2018 was $0.5 million (December 31, 2017 – $0.5 million).

As at March 31, 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:

- total leverage, pursuant to which the ratio of adjusted indebtedness to EBITDAX (as defined below) for the four quarters most recently ended cannot exceed 3.5 to 1.0 (Senior Notes – 3.75 to 1.00) (as at March 31, 2018— 2.4 to 1.0);
- senior leverage, pursuant to which the ratio of senior adjusted indebtedness to EBITDAX (as defined below) for the four quarters most recently ended cannot exceed 3.0 to 1.0 (Senior Notes – 3.25 to 1.00) (as at March 31, 2018 — 2.4 to 1.0);
- asset coverage, pursuant to which the ratio of 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 (Senior Notes – 1.3 to 1.00) (1.9 to 1.0 as at March 31, 2018); and
- current ratio, pursuant to which the ratio of consolidated current assets, plus any undrawn capacity under the Revolving Facility, to consolidated current liabilities at the end of any fiscal quarter cannot be less than 1.0 to 1.0 (subordinated notes – 0.85 to 1.00). Prior to first quarter-end of 2018, the note holder of the Revolving Facility amended the current ratio covenant for Revolving Facility to 0.85 to 1.00 for the first quarter of 2018 (as at March 31, 2018— 0.9 to 1.0). 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 applicable covenants as at March 31, 2018.

Shareholders' Equity

At March 31, 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 quarter of 2018, the Company purchased and cancelled 15,000 shares under the NCIB at a weighted average cost of $0.48 per share.

As of the date of the MD&A, there are 115.9 million common shares, 2.6 million stock options, 1.9 million RSUs, 0.5 million PSUs (which will be settled subject to a performance multiplier from 0 to 2), 0.3 million DSUs and 5.5 million warrants outstanding.

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 well within the financial covenants imposed on it under its outstanding debt agreements. Total debt to Adjusted EBITDAX at March 31, 2018 was 2.4 to 1.0 (December 31, 2017 – 2.0 to 1.0), which was well below the financial covenant requirement of 3.0 to 1.0 under the Revolving Facility. The Company plans to maintain a prudent financial position by actively managing its capital program with careful consideration of the commodity price environment to optimize leverage, liquidity and cash flows.

During the first quarter of 2018, PPR's capital spending outpaced its cash flows from operations as the Company decided to complete over 50% of its planned 2018 capital program so to take advantage of oil price recovery and to gear up the Company for growth. Though PPR's working capital deficit and total debt to Adjusted EBITDAX ratio increased during the quarter, PPR anticipates the annual 2018 capital program to be funded primarily with cash flows from operations and as such expects the ratios to improve over time.

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 quarter 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 March 31, 2018, the Company has incurred a total of $27.0 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 March 31, 2018, the Company incurred a total of $0.6 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 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2
Oil and natural gas revenue	**19,283**	20,510	17,611	21,682	19,208	17,060	9,334	9,151
Royalties	**(2,537)**	(2,171)	(2,164)	(3,009)	(3,029)	(2,270)	(1,050)	(924)
Unrealized (loss) gain on derivatives	**(5,199)**	(6,960)	(2,586)	4,471	5,858	(7,231)	(1,936)	(10,959)
Realized (loss) gain on derivatives	**(1,212)**	851	2,222	1,150	703	1,362	2,257	2,539
Revenue net of realized and unrealized (losses) gains on derivative instruments	**10,335**	12,230	15,083	24,294	22,740	8,921	8,605	(193)
Net (loss) earnings	**(11,742)**	(44,145)	(11,985)	1,066	7,262	(8,782)	(11,588)	(43,223)
Per share – basic & diluted[1]	**(0.10)**	(0.38)	(0.10)	0.01	0.07	(0.09)	(0.12)	(0.44)
Adjusted funds from operations [2]	**3,457**	5,545	4,536	7,060	5,934	7,107	1,810	3,252
Per share – basic & diluted [3]	**0.03**	0.05	0.04	0.06	0.06	0.07	0.02	0.03

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 decrease considerably in the fourth quarter of 2016 and thereafter.

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. Realized losses on derivatives incurred in the first quarter of 2018 were due to improved commodity prices, which contrasted with realized gains in the fourth quarter of 2017. 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.

PPR recorded a net loss of $43.2 million 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.

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 March 31, 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, with earlier adoption permitted if the entity is also applying IFRS 15 Revenue from Contracts with Customers. 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 Canadian 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 quarter 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, PPR 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 ratio 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

PPR 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)	March 31, 2018	December 31, 2017
Current assets	18,557	19,588
Less current derivative instrument assets	(770)	895
Current assets excluding current derivatives instruments	17,787	18,693
Current liabilities	39,364	28,594
Less flow-through share premium	(683)	(711)
Less current derivative instrument liabilities	(7,271)	(4,156)
Less current portion of decommissioning liability	(2,300)	(2,300)
Less warrant liability	(463)	(533)
Current liabilities excluding current derivatives instruments, current portion of decommissioning liabilities, flow-through share premium and warrant liability	28,647	20,894
Working capital (deficit)	(10,860)	(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 March 31	
($000s)	**2018**	2017
Cash flow from operating activities	**3,375**	1,655
Changes in non-cash working capital	**(391)**	(502)
Funds from Operations	**2,984**	1,153
Other	**19**	62
Settlement of decommissioning liabilities	**660**	4,042
Restructuring costs	**187**	—
Transaction costs	**32**	677
Adjusted Funds from Operations	**3,882**	5,934

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 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 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 March 31	
($000s)	**2018**	2017
Net earnings (loss) before income tax	**(11,770)**	7,158
Add (deduct):		
Interest	**1,600**	309
Depletion and depreciation	**7,416**	8,201
Exploration and evaluation expense	**147**	8
EBITDAX	**(2,607)**	15,676
Unrealized loss (gain) on derivative instruments	**5,199**	(5,858)
Impairment loss	**—**	—
Accretion	**564**	470
Loss (gain) on foreign exchange	**1,553**	(85)
Reorganization costs[1]	**187**	—
Share – based compensation	**164**	124
Gain on sale of properties	**—**	(548)
Gain on business combination	**—**	(4,343)
Gain on warrant liability	**(70)**	
Transaction costs	**32**	677
Adjusted EBITDAX before pro-forma adjustments	**5,022**	6,113
Pro-forma impact of acquisitions	**—**	2,394
Adjusted EBITDAX	**5,022**	8,507

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