Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three Months Ended March 31, 2019

Dated: May 8, 2019

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, 2019. Results of operations of Marquee Energy Ltd. ("Marquee") have been included in PPR's financial statements and MD&A since November 21, 2018, the closing date of the acquisition. This MD&A is dated May 8, 2019 and should be read in conjunction with the unaudited condensed interim consolidated financial statements for the three months ended March 31, 2019 (the "Interim Financial Statements"), the audited consolidated financial statements of PPR as at and for the year ended December 31, 2018 (the "2018 Annual Financial Statements") and the 2018 annual MD&A (the "Annual MD&A"). Additional information relating to PPR, including the Company's December 31, 2018 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	
($000s except per unit amounts)	**2019**	2018
Financial		
Oil and natural gas revenue	**22,895**	19,283
Net loss	**(21,260)**	(11,742)
Per share – basic & diluted	**(0.12)**	(0.10)
Adjusted funds flow[1]	**1,248**	3,222
Per share – basic & diluted	**0.01**	0.03
Net capital expenditures[2]	**3,685**	14,952
Production Volumes		
Crude oil (bbl/d)	**3,892**	3,089
Natural gas (Mcf/d)	**11,568**	8,373
Natural gas liquids (bbl/d)	**142**	124
Total (boe/d)	**5,962**	4,609
% Liquids	**68%**	70%
Average Realized Prices		
Crude oil ($/bbl)	**56.70**	61.57
Natural gas ($/Mcf)	**2.44**	2.09
Natural gas liquids ($/bbl)	**38.65**	52.78
Total ($/boe)	**42.67**	46.49
Operating Netback ($/boe)[3]		
Realized price	**42.67**	46.49
Royalties	**(3.36)**	(6.12)
Operating costs	**(23.47)**	(20.11)
Operating netback	**15.84**	20.26
Realized losses on derivative instruments	**(0.24)**	(2.92)
Operating netback, after realized losses on derivative instruments	**15.60**	17.34

First quarter 2019 highlights:

- Average production for the first quarter of 2019 was 5,962 boe/d (68% liquids), an increase of 29% from the same quarter in 2018. Production increase was driven by incremental production volumes from the Marquee acquisition completed in the fourth quarter of 2018 and PPR’s 2018 and 2019 development program, partially offset by production outages of approximately 400 boe/d during the first quarter of 2019 due to extended period of extreme cold weather condition, shut-in gas production and natural declines. Subsequent to the first quarter of 2019, the Company has resumed production impacted by cold weather and is currently producing well within its 2019 production guidance range of 6,100 to 6,500 boe/d.

[1,2,3] Adjusted funds flow, net capital expenditures and operating netback are non-IFRS measures and are defined below under “Other Advisories”.

- Net loss was $21.3 million for the first quarter of 2019, compared to a net loss of $11.7 million in the same quarter of 2018. The $9.6 million increase in net loss was primarily due to non-cash items such as: $9.3 million increase in unrealized derivative losses resulted from changes in the marked-to-market value of open derivative contracts, $2.6 million increase in depletion, depreciation and amortization, partially offset by $2.7 million increase in unrealized foreign exchange gain.

- Operating netbacks1 before realized hedging losses was $8.5 million (or $15.84/boe) for the first quarter of 2019, a $0.1 million (or $4.42/boe) decrease from the first quarter of 2018. On a per boe basis, the decrease was due to lower realized prices of $3.82/boe, higher operating expenditures of $3.36/boe, partially offset by $2.76/boe decrease in royalty expenses. The financial impact from lower per boe operating netbacks was entirely offset by higher production, resulting in nominal change in total operating netbacks from the first quarter of 2018. The quarter-over-quarter decrease in realized prices was primarily due to lower crude oil and NGL benchmark prices. Higher operating expenditures per boe was incurred on maintenance to combat the cold weather conditions and to restore the relating production outages. A decrease in per boe royalties related to lower crown royalty rates, favorable GCA deductions related to the Marquee acquisition and substantially less production from the Wheatland area that bear higher royalty rates than the corporate average.

- Operating netbacks after $0.1 million (or $0.24/boe) of realized hedging loss was $8.4 million (or $15.60/boe) for the first quarter of 2019, reflecting an increase of $1.2 million (or $1.75/boe) from the same period in 2018. The increase was attributable to lower realized hedging loss by $2.68/boe from the first quarter of 2018 due to lower benchmark prices in the first quarter of 2019.

- In this MD&A, adjusted funds flow[2] includes decommissioning liability settlements, which were previously excluded from the calculation in accordance with common industry practice, to conform to recent direction expressed by Alberta Securities Commission staff regarding funds flow disclosure by oil and gas issuers. By including the cost of decommissioning liability settlements in adjusted funds flow for the first quarter, the current calculation results in a correspondingly lower adjusted funds flow amount than under the previous methodology. With many oil and gas issuers continuing to exclude decommissioning settlements from their own funds flow calculations, the Company emphasizes that its adjusted funds flow measurement may not be comparable with the calculation of similar measurements used by other companies. Applying the previous methodology, adjusted funds flow (excluding $3.0 million of decommissioning liability settlements) would have been $4.2 million (2018 – $3.9 million) for the first quarter of 2019; while under the current methodology, adjusted funds flow (including $3.0 million of decommissioning liability settlements) was $1.2 million (2018 – $3.2 million).

- Adjusted funds flow in the first quarter of 2019 decreased by $2.0 million ($0.01/share) compared to the same quarter in 2018, due to the impact of decommissioning settlements. PPR incurred $3.0 million or 64% of the 2019 budgeted decommissioning expenditures of $4.7 million. The high concentration of spending was attributable to the Company's focused effort on one of its winter-access-only area where the Company successfully achieved economies of scale, combined with "catch-up" compliance activities on certain newly acquired Marquee properties. Excluding the $2.3 million quarter-over-quarter increase in decommissioning spending, adjusted funds flow increased by $0.3 million driven by higher operating netbacks after realized hedging losses, partially offset by higher cash interest expenses.

- Capital expenditures in the quarter were $3.8 million. PPR focused its capital activities during the first quarter of 2019 in the Evi area, where the Company incurred $2.8 million primarily for the completion, equipping and tie-in of two gross (2.0 net) Slave Point wells, both of which came on production in late February of 2019.

[1,2] Operating netback and adjusted funds flow are non-IFRS measures and are defined below under "Other Advisories".

- On March 29, 2019, the Company's remaining $17.3 million of capital commitment in the Wheatland area was eliminated by mutual agreement of the Company and the lessor for an immaterial cash consideration.

- As of March 31, 2019, PPR had US$56.5 million of borrowings (CAD$74.9 million equivalent applying the March 31, 2019 exchange rate of $1.00 USD to $1.3363 CAD) drawn against the US$60 million Revolving Facility (CAD$80.2 million equivalent using the quarter-end exchange rate) and US$29.9 million of Subordinated Notes (defined herein) (CAD$40.0 million equivalent using the using the quarter-end exchange rate) plus a working capital deficit of CDN$7.7 million (US$5.8 million equivalent using the quarter-end exchange rate). The CAD$9.9 million increase in borrowings from December 31, 2018 was largely used to pay down accounts payable.

- At March 31, 2019, using the prevalent forward commodity prices the Company recorded $7.9 million of marked-to-market liabilities (December 31, 2018 – $6.6 million of assets) relating to derivative contracts settling the next three years.

- Subsequent to March 31, 2019, the Company's US$60 million borrowing base under its Revolving Facility was confirmed. Further, our lenders also agreed to relax certain financial covenant ratios for the remainder of the year solely due to the impact of widened Canadian crude oil price differentials during the fourth quarter of 2018 on the computation of PPR's financial covenants for 2019. Had the fourth quarter 2018 oil differentials been normalized, our financial covenants would be well in line with the original thresholds.

Outlook

PPR is encouraged by the rebounds in Canadian oil prices from Q4 2018 and is executing its 2019 capital budget as planned. As such, the Company maintains its 2019 guidance with no change from its previous disclosures (see 2018 Annual MD&A).

Prior Year Arrangement Agreement

On November 21, 2018 PPR completed the acquisition of Marquee, an oil and natural gas exploration and production company listed on the TSX Venture Exchange, by way of a plan of arrangement under the Business Corporations Act (Alberta) (the "Arrangement"). Pursuant to the Arrangement, PPR acquired all of the outstanding Marquee common shares on a share exchange basis, with Marquee shareholders receiving an aggregate of 38,608,416 PPR shares based on an exchange ratio of 0.0886 PPR common shares for each Marquee share. The acquisition of Marquee common shares was accounted for as a business combination using the acquisition method of accounting whereby PPR was deemed to be the acquirer of the Marquee business and the assets and liabilities assumed were recorded at their fair values. Transaction costs associated with the acquisition were expensed when incurred.

Results of Operations

Production

	Three Months Ended March 31	
	2019	2018
Crude oil (bbl/d)	3,892	3,089
Natural gas (Mcf/d)	11,568	8,373
Natural gas liquids (bbl/d)	142	124
Total (boe/d)	5,962	4,609
Liquids Weighting	68%	70%

Average production for the first quarter of 2019 was 5,962 boe/d (68% liquids), an increase of 29% from the first quarter of 2018. Production increase was driven by PPR's 2018 and 2019 development program and incremental production volumes from the Marquee acquisition completed in Q4 2018, partially offset by production loss of approximately 400 boe/d during the first quarter of 2019 due to extended period of extreme cold weather condition, shut-in gas production and natural declines. Subsequent to the first quarter of 2019, the Company has resumed production impacted by cold weather and is currently producing well within its 2019 production guidance range of 6,100 to 6,500 boe/d.

During the first quarter of 2019, PPR completed, equipped and tied in two Slave Point wells drilled in the EVI area late last year. The wells commenced production in late February 2019. Combined production from the two wells averaged 219 boe/d (93% liquids weighting) for the month of March 2019.

Revenue

	Three Months Ended March 31	
($000s, except per unit amounts)	2019	2018
Revenue		
Crude oil	19,860	17,116
Natural gas	2,541	1,578
Natural gas liquids	494	589
Oil and natural gas revenue	22,895	19,283
Average Realized Prices		
Crude oil ($/bbl)	56.70	61.57
Natural gas ($/Mcf)	2.44	2.09
Natural gas liquids ($/bbl)	38.65	52.78
Total ($/boe)	42.67	46.49
Benchmark Prices		
Crude oil - WTI ($/bbl)	73.05	79.57
Crude oil - Edmonton Light Sweet ($/bbl)	66.08	71.89
Natural gas - AECO month index-7A ($/Mcf)	1.94	1.85
Natural gas - AECO daily index-5A ($/Mcf)	2.60	2.08
Exchange rate - US$/CDN$	0.75	0.79

PPR's first quarter 2019 revenue increased by 19% or $3.6 million from the first quarter of 2018. The 16% increase in crude oil revenue resulted from a 26% increase in oil production volumes, partially offset by an 8% reduction in realized oil prices. PPR's product prices generally correlate to changes in the benchmark prices. In the first quarter of 2019, the average WTI price decreased by $6.52/bbl, while Edmonton par decreased by $5.81/bbl. Production curtailments mandated by the Alberta Government have resulted in a narrowing of the Canadian oil differentials during the first quarter of 2019. WCS to WTI differential decreased to $14.36/bbl (Q4 2018 – $42.35/bbl) and the Edmonton Light Sweet to WTI differential also decreased to $6.97/bbl (Q4 2018 – $34.86/bbl).

First quarter 2019 natural gas revenue increased by 61% or $1.0 million, compared to the same quarter in 2018, reflecting a 38% increase in production volumes and a 17% increase in realized natural gas prices. A significant portion of the increase in the first quarter 2019 natural gas production was due to the Arrangement which closed on November 21, 2018.

On a combined total per boe basis, the 8% or $3.82/boe decrease in the overall average realized prices from the first quarter of 2018 correlated to the lower crude oil and natural gas liquids realized prices. A slight decrease in the liquids-weighted production mix to 68% in the first quarter of 2019 further contributed to the decrease.

Royalties

	Three Months Ended March 31	
($000s, except per boe)	**2019**	2018
Royalties	**1,801**	2,537
Per boe	**3.36**	6.12
Percentage of revenue	**7.9%**	13.2%

The Company pays royalties to respective provincial governments and landowners in accordance with the established royalty regime. 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.

On a percentage of revenue basis, royalties for the three months ended March 31, 2019 decreased from the corresponding period in 2018 due to substantially lower production in the Wheatland area, favorable GCA deductions related to the Marquee acquisition and a decrease in the crude oil prices. Production in the Wheatland area is subject to flat freehold royalty rates, which are above the average royalty rate of the Company.

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)	**2019**	2018
Realized loss on derivatives	**(127)**	(1,212)
Unrealized loss on derivatives	**(14,509)**	(5,199)
Total loss on derivatives	**(14,636)**	(6,411)
Per boe		
Realized loss on derivatives	**(0.24)**	(2.92)
Unrealized loss on derivatives	**(27.04)**	(12.53)
Total loss on derivatives	**(27.28)**	(15.45)

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 derivative 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 increase in the unrealized loss on derivatives recognized in the first quarter of 2019 is primarily due to an increase in WTI futures pricing and a further depreciation of the Canadian dollar against the US dollar, as compared to the first quarter of 2018.

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, 2019, the Company held the following outstanding derivative contracts:

Remaining Term	Reference	Total Daily Volume (bbl)	Premium/ bbl	Weighted Average Price/bbl
Crude Oil Swaps				
April 1, 2019 - March 31, 2019	US$ WTI	900		$55.68
April 1, 2019 - December 31, 2019	CDN$ WTI	150		$64.39
April 1, 2019 - June 30, 2019	US$ WTI	325		$52.75
April 1, 2019 - May 31, 2019	US$ WTI	250		$52.65
July 1, 2019 - September 31, 2019	US$ WTI	500		$52.50
October 1, 2019 -December 1, 2019	US$ WTI	450		$52.00
January 1, 2020 - March 31, 2020	US$ WTI	450		$51.50
April 1, 2020 - June 30, 2020	US$ WTI	425		$51.00
July 1, 2020 - September 30, 2020	US$ WTI	400		$50.75
October 1, 2020 - December 1, 2020	US$ WTI	400		$50.50
July 1, 2020 - December 31, 2020	US$ WTI	500		$55.00
Crude Oil Sold Call Options				
April 1, 2019 – December 31, 2019	CDN$ WTI	400		$85.00
January 1, 2020 – December 31, 2020	US$ WTI	400		$60.50
Crude Oil Put Options				
April 1, 2019 - June 30, 2019	US$ WTI	400	$4.95	$45.00
July 1, 2019 - December 31, 2019	US$ WTI	450	$6.29	$55.00
April 1, 2019 -June 30, 2019	CDN$ WTI	100	$2.75	$73.42
January 1, 2020 - March 31, 2020	CDN$ WTI	400	$3.65	$56.05
April 1, 2020 - June 30, 2020	CDN$ WTI	300	$6.00	$71.30
January 1, 2020 - March 31, 2020	US$ WTI	400		$42.50
January 1, 2020 - March 31, 2020	US$ WTI	300		$45.00
January 1, 2021 - March 31, 2021	US$ WTI	200		$42.50
January 1, 2021 - December 31, 2021	US$ WTI	650		$40.00
Crude Oil Collars				
April 1, 2019 – December 31, 2019	US$ WTI	400		$52.50/60.00
April 1, 2019 – December 31, 2019	US$ WTI	275		$50.00/57.00
January 1, 2020 – December 31, 2020	US$ WTI	175		$49.00/ 54.75
April 1, 2019 – December 31, 2019	US$ WTI	300		$50.00/60.00
April 1, 2019 – December 31, 2019	US$ WTI	150		$52.50/63.10
January 1, 2020 – March 31, 2020	US$ WTI	400		$52.50/65.00
January 1, 2020 – March 31, 2020	US$ WTI	300		$55.00/66.15
July 1, 2020 - December 31, 2020	US$ WTI	500		$50.00/59.00

Remaining Term	Reference	Total Daily Volume (bbl)	Premium/ bbl	Weighted Average Price/bbl
January 1, 2021 – March 31, 2021	US$ WTI	200		$52.50/65.00
January 1, 2021 – December 31, 2021	US$ WTI	650		$50.00/64.25
Crude Oil Differential Swaps				
April 1, 2019 - June 30, 2019	CDN$ WCS - WTI Diff @ Hardisty	500		$17.85
April 1, 2019 - June 30, 2019	CDN$ SW - WTI Diff @ Edmonton	1500		$8.25

Remaining Term	Reference	Total Daily Volume (GJ)	Premium/ GJ	Weighted Average Price/GJ
Natural Gas Swaps				
April 1, 2019 - March 31, 2019	AECO 7A Monthly Index	3,000		$2.73
July 1, 2019 - December 31, 2019	US$ NYMEX	3,000		$3.15
April 1, 2019 - October 31, 2019	US$ NYMEX	1,800		$2.70
July 1, 2019 - December 31, 2019	US$ NYMEX	1,420		$2.70
Natural Gas Put Options				
April 1, 2019 - March 31, 2019	AECO 7A Monthly Index	1700	$0.13	$1.05
April 1, 2019 - June 30, 2019	AECO 7A Monthly Index	1200	$0.25	$1.11
January 1, 20120 - March 30, 2020	AECO 7A Monthly Index	4000	$0.15	$1.16
April 1, 2020 - June 30, 2020	AECO 7A Monthly Index	4600	$0.25	$1.11
Natural Gas Collars				
April 1, 2019 - March 31, 2019	AECO 7A Monthly Index	3000		$2.92/2.40
April 1, 2019 - June 30, 2019	AECO 7A Monthly Index	3000		$2.14/1.90

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

Operating Expenses

	Three Months Ended March 31	
($000s, except per boe)	**2019**	2018
Lease operating expense	**9,289**	6,089
Transportation and processing	**1,551**	1,134
Production and property taxes	**1,755**	1,117
Total operating expenses	**12,595**	8,340
Per boe	**23.47**	20.11

During the first quarter 2019 lease operating expenses increased by 53% or $3.2 million, the increase was the result of a 29% increase in production volumes combined with higher repair and maintenance expenses in the Princess and EVI areas due to extreme cold weather.

Transportation and processing expense for the first three months of 2019 increased by $0.4 million as compared to the same period in 2018. The increase was largely related to a 38% increase of natural gas production resulting in increased third-party natural gas processing and transportation costs.

Production and property tax expense for the three months ended March 31, 2019 increased by $0.6 million as compared to the same period in 2018. The increase in the first quarter of 2019 is a result of a $0.5 million increase related to the properties acquired from the Arrangement.

Operating Netback

	Three Months Ended March 31	
($ per boe)	**2019**	2018
Revenue	**42.67**	46.49
Royalties	**(3.36)**	(6.12)
Operating costs	**(23.47)**	(20.11)
Operating netback	**15.84**	20.26
Realized losses on derivative instruments	**(0.24)**	(2.92)
Operating netback, after realized losses on derivative instruments	**15.60**	17.34

PPR's operating netback after realized losses on derivative instruments was $15.60/boe for the three months ended March 31, 2019, which represents a decrease of $1.74/boe compared with the same quarter of 2018. The decrease was due to lower realized prices by $3.82/boe and higher operating expenses by $3.36/boe from the comparative three-month period of 2018, partially offset by 2.76/boe and 2.68/boe reductions in royalties royalty and realized losses on derivative instruments, respectively.

General and Administrative ("G&A") Expenses

	Three Months Ended March 31	
($000s, except per boe)	**2019**	2018
Gross cash G&A expenses	**2,468**	2,755
Gross share-based compensation expense	**224**	213
Less amounts capitalized	**(579)**	(632)
Net G&A expenses	**2,113**	2,336
Per boe	**3.94**	5.63

For the three months ended March 31, 2019, gross cash G&A decreased by $0.3 million or 10% compared to the same period in 2018.

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, the vesting period over which the related expense is recognized and timing and quantity of forfeitures.

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 2019, the Company granted 2,373,633 restricted share units ("RSUs") to officers and employees. RSUs vest evenly over a three-year period. As at March 31, 2019, 3,464,176 RSUs were outstanding. In addition, the Company issued 185,685 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, 2019, 821,397 DSUs were 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 March 31, 2019, there were 292,070 PSUs outstanding and 4,460,472 options with a weighted average strike price of $0.49 per share, of which 1,578,792 were exercisable at a weighted average strike price of $0.83 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 and past practice 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)	**2019**	2018
Interest expense	**3,432**	1,600
Accretion expenses	**869**	564
Total finance costs	**4,301**	2,164
Per boe	**8.02**	5.22

Interest expense is primarily comprised of interest incurred related to the Company's outstanding borrowings. The increase in interest expense of $1.8 million for the three months ended March 31, 2019 as compared to the comparable period in 2018 related to increased average borrowings, higher effective interest rates on the Company's Revolving Facility, the inclusion of $0.3 million interest expense on lease obligations and higher amortization of deferred financing fees related to the incremental financing completed upon the Arrangement.

Of the $3.4 million of interest expense incurred in the three months ended March 31, 2019, $0.5 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, 2019 was 9.9% (2018 – 8.7%).

Accretion charges are non-cash expenses and primarily relate to the decommissioning liabilities. Accretion increased by $0.3 million during the first quarter of 2019 from the same period due to additional decommissioning liabilities acquired from the Arrangement.

Loss on Foreign Exchange

	Three Months Ended March 31	
($000s)	**2019**	2018
Realized (gain) loss on foreign exchange	**(80)**	201
Unrealized (gain) loss on foreign exchange	**(1,321)**	1,352
(Gain) Loss on foreign exchange	**(1,401)**	1,553

Foreign exchange gains incurred in the three months ended March 31, 2019 related largely to borrowings denominated in US dollars (see "Capital Resources and Liquidity" section below).

Exploration and Evaluation Expense

	Three Months Ended March 31	
($000s, except per boe)	**2019**	2018
Exploration and evaluation expense	**96**	147
Per boe	**0.18**	0.35

Exploration and evaluation expenses incurred as at March 31, 2019 and March 31, 2018 were comprised of undeveloped land expiries.

Depletion and Depreciation

	Three Months Ended March 31	
($000s, except per boe)	**2019**	2018
Depletion and depreciation	**9,294**	7,416
Depreciation on right-of-use assets	**686**	—
Per boe	**18.60**	17.88

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 2019 from the comparable period in 2018 reflects the assets and associated reserves acquired through the Arrangement, as well as changes in assumptions used in the Company's independent annual reserves evaluation.

Depreciation on the right-of-use assets reflects the depreciation charge recognized for the first three months of 2019, after the adoption of IFRS 16 – *Leases*, effective January 1, 2019. The Company adopted IFRS 16 using the modified retrospective method whereby the standard is applied retrospectively with the cumulative effect of initially applying the standard recorded to the opening retained earnings as at January 1, 2019 without any restatement to the comparative financial statements. As such, for the three months ended March 31, 2018, no depreciation was recognized on right-of-use assets.

Net Capital Expenditures[1]

	Three Months Ended March 31	
($000s)	**2019**	2018
Drilling and completion	**2,530**	9,504
Equipment, facilities and pipelines	**570**	3,414
Land	**169**	495
Capitalized overhead and other	**486**	652
Total Capital expenditures	**3,755**	14,065
Acquisitions – business combination	**—**	887
Asset dispositions (net of acquisitions)	**(70)**	—
Net Capital Expenditures	**3,685**	14,952

[1] Net capital expenditures are non-IFRS measures and are defined below under "Other Advisories".

Capital expenditures prior to acquisitions or dispositions in the quarter were $3.8 million. PPR focused its capital activities during the first quarter of 2019 in the Evi area where the Company incurred $2.8 million related to the completion, equipping and tie-in of two gross (2.0 net) Slave Point wells, both of which came on production in late February 2019.

PPR focused its capital activities during the first quarter of 2018 in the Princess, Wheatland and Evi areas. In Princess and Wheatland, the Company drilled a total of 6 gross wells (6.0 net). 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. Furthermore, 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.

Decommissioning Liabilities

PPR's decommissioning liabilities at March 31, 2019 were $146.3 million (December 31, 2018 - $148.5 million). The decrease of $2.2 million was due to settlements of decommissioning obligations totaling $3.0 million, partially offset by $0.8 million of accretion of decommissioning liabilities.

Capital Resources and Liquidity

Capital Resources

Working Capital

At March 31, 2019, the Company had a working capital deficit (as defined in "Other Advisories" below) of $7.7 million (December 31, 2018 – $16.1 million). The decrease in the working capital deficit from December 31, 2018 was primarily the result of paying down accounts payable and accrued liabilities with adjusted funds flows and debt borrowing, combined with increase in accrued revenue from higher oil prices.

Revolving Facility

On November 21, 2018, in conjunction with the closing of the Marquee Energy Ltd. Arrangement, PPR amended the borrowing base under its senior secured revolving note facility ("Revolving Facility") with a maturity date of October 31, 2020. The amended Revolving Facility provided a borrowing base of US$65.0 million until January 31, 2019, an increase of US$20.0 million from the June 21, 2018 amended agreement. After January 31, 2019, the borrowing base was automatically reduced by US$5.0 million. The US$5.0 million was intended to bridge short-term liquidity needs from the Arrangement.

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 CAD$54 million or US$30 million. As at March 31, 2019, the Company had US$56.5 million (CAD$74.9 million equivalent) drawn under the facility, comprised of US$26.5 million of USD denominated notes (CAD$35.4 million equivalent using the March 31, 2019 quarter end exchange rate) and CAD$39.5 million of CAD denominated notes (US$30.0 million equivalent using exchange rate at the time of initial borrowing) 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 2019. Subsequent to March 31, 2019, the Company's US$60 million borrowing base under its Revolving Facility was confirmed.

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.

As at March 31, 2019, PPR had outstanding letters of credit of $4.9 million. The letters of credit are issued by a financial institution at which PPR posted 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, 2019, $2.0 million of deferred costs related to the Revolving Facility was netted against its carrying value (December 31, 2018 – $2.0 million).

Subordinate Senior Notes

On November 21, 2018, upon closing of the Arrangement, PPR issued an additional US$12.5 million (CDN $16.7 million using the March 31, 2019 quarter end exchange rate of $1.00 USD to $1.3363 CAD) of subordinated senior notes ("Senior Notes") due October 31, 2021. In addition to the US$16 million Senior Notes issued on October 31, 2017 (CDN $21.4 million using the March 31, 2019 quarter end exchange rate) due October 31, 2021, Senior Notes outstanding as at March 31, 2019 totaled US$28.5 million (CDN $38.1 million using the March 31, 2019 quarter end exchange rate). Senior Notes 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 issuances of the Senior Notes, the Company issued 6,318,000 warrants. The warrants are classified as financial liabilities due to a cashless exercise provision and are 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, 2019 was $0.5 million.

As at March 31, 2019, $1.1 million of deferred costs related to PPR's Senior Notes was netted against its carrying value (December 31, 2018 – $1.2 million).

Covenants

Subsequent to March 31, 2019, PPR has finalized terms of amending agreements with its lender respecting its Revolving Facility and Senior Notes which relax certain financial covenant thresholds effective for the quarter ending March 31, 2019 through the quarter ending December 31, 2019. The relaxation was intended to accommodate the lasting impact from widened Canadian crude oil price differentials during the fourth quarter of 2018 on the computation of PPR's financial covenants for 2019. The financial covenants applicable to March 31, 2019 are as follows:

Financial Covenant	Revolving Facility Requirement	Senior Note Requirement	As at March 31, 2019
Total Leverage – adjusted indebtedness to EBITDAX	Cannot Exceed 4.75 to 1.0	Cannot Exceed 5.00 to 1.00	4.1 to 1.0
Senior Leverage – senior adjusted indebtedness to EBITDAX	Cannot Exceed 3.25 to 1.0	Cannot Exceed 3.50 to 1.0	2.6 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	1.4 to 1.0
Current ratio – consolidated current assets, plus any undrawn capacity under the Revolving Facility, to consolidated current liabilities	Cannot be less than 0.85 to 1.0	Cannot be less than 0.85 to 1.0	1.0 to 1.0

The Company was in compliance with all covenants as at March 31, 2019.

Shareholders' Equity

At March 31, 2019, PPR had consolidated share capital of $135.8 million (2018 – $136.1 million) and had 171.3 million outstanding common shares. In addition, PPR had 4.5 million options (2018 – 2.2 million), 0.3 million PSUs (2018 – 0.3 million) (which will be settled subject to a performance multiplier ranging from 0 to 2), 0.8 million DSUs (2018 – 0.6 million), 4.8 million warrants (2018 – 8.0 million) and 3.5 million RSUs (2018 – 1.6 million) outstanding as at March 31, 2019.

On November 29, 2018, the Toronto Stock Exchange ("TSX") accepted for filing 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 5,000,000 common shares during the period from December 4, 2018 to December 3, 2019. Shares purchased under the bid will be cancelled. Transactions under the NCIB 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.

For the quarter ended March 31, 2019, 643,130 shares were purchased and cancelled.

As of the date of this MD&A, there are 171.3 million common shares, 3.5 million RSUs, 4.5 million stock options, 0.3 million PSUs, and 13.1 million outstanding warrants.

Capital Management and liquidity

PPR’s objective when managing capital is to maintain a flexible capital structure and sufficient liquidity to meet its financial obligations and to execute its planned capital expenditure program. The Company considers its capital structure to include shareholders’ equity, the available borrowing under outstanding debt agreements, adjusted funds flow and working capital.

The Company monitors its current and forecasted capital structure in response to changes in economic conditions and the risk characteristics of its oil and gas properties. Adjustments are made on an ongoing basis in order to meet its capital management objectives. 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, though there is no certainty that any of these additional sources of capital would be available if required.

In light of continued volatility in benchmark oil prices and Canadian crude oil differentials, coupled with the lack of market support for growth in publicly-traded energy equities, PPR’s short-term capital management objective is to fund its capital expenditures necessary for the replacement of production declines using adjusted funds flow. Value-creating activities may be financed with a combination of adjusted funds flow and other sources of capital. 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 flow.

PPR monitors its capital structure using the ratio of total debt to trailing twelve months’ Bank Adjusted EBITDAX (as defined in “Other Advisories” below). Total debt to Bank 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 Bank Adjusted EBITDAX at March 31, 2019 was 4.1 to 1.0 (December 31, 2018 – 3.4 to 1.0). Management of debt levels is a priority for PPR and its 2019 capital program was designed with this key objective in mind.

Canadian crude oil differentials tightened significantly during the first quarter of 2019 and as such, operating netbacks have improved from the fourth quarter of 2019. PPR's management believes that with the high-quality liquids-rich reserve base, deep development inventory, solid hedging program and steady base cash flows, the Company is well positioned to execute its business strategy.

Contractual Obligations and Commitments

Contractual obligations and commitments are outlined in Note 20 of the Interim Financial Statements. The most significant change from December 31, 2018 related to the removal of lease commitments which are now recorded as lease liabilities on the balance sheet (see Note 3 to the Interim Financial Statements).

Lease Acquisition Capital Commitment

On March 29, 2019, the Company’s remaining $17.3 million of capital commitment in the Wheatland area was eliminated by mutual agreement of the Company and the lessor for an immaterial cash consideration.

Flow-through Share Commitment

Pursuant to the bought deal financing which closed on October 11, 2018 and the related over-allotment option, the Company issued 3,750,150 flow-through common shares with respect to CEE at $0.46 per share. As defined by the *Income Tax Act*, the Company has until December 31, 2019 to incur $1.8 million of CEE costs related to this flow-through common share issuance. As at March 31, 2019, PPR incurred a total of $0.2 million towards this commitment.

Supplemental Information

Financial – Quarterly extracted information

($000)	2019 Q1	2018 Q4	2018 Q3	2018 Q2	2018 Q1	2017 Q4	2017 Q3	2017 Q2
Oil and natural gas revenue	22,895	13,542	27,810	24,187	19,283	20,510	17,611	21,682
Royalties	(1,801)	(1,902)	(4,806)	(3,815)	(2,537)	(2,171)	(2,164)	(3,009)
Unrealized (loss) gain on derivatives	(14,509)	26,968	(1,884)	(9,316)	(5,199)	(6,960)	(2,586)	4,471
Realized gains (losses) on derivatives	(127)	(1,269)	(3,596)	(2,943)	(1,212)	851	2,222	1,150
Revenue net of realized and unrealized gains (losses) on derivative instruments	6,458	37,339	17,524	8,113	10,335	12,230	15,083	24,294
Net earnings (loss)	(21,260)	(3,532)	(2,627)	(15,064)	(11,742)	(44,145)	(11,985)	1,066
Per share – basic & diluted	(0.12)	(0.02)	(0.02)	(0.13)	(0.10)	(0.38)	(0.10)	0.01
Adjusted funds flow [(1)]	1,248	(5,346)	5,533	4,625	3,222	5,512	4,185	6,550
Per share – basic & diluted	0.01	(0.04)	0.05	0.04	0.03	0.05	0.04	0.06

1 Adjusted funds flow 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 Marquee, 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. The Company incurred net losses in several quarters due to non-cash expenses, including unrealized derivative losses, impairments to D&P and E&E assets, DD&A and accretion expense and foreign exchange losses related to the US denominated borrowings after October 31, 2017. The Company has maintained positive adjusted funds flow for the most recent current quarter and all past seven quarters, with the exception of Q4 2018. Negative funds flow from operations in the fourth quarter of 2018 was the result of negative operating netbacks after realized losses on derivatives instruments caused by significant widening in Canadian oil differentials which caused a substantial reduction in realized revenue for the quarter.

First quarter of 2019 oil and natural gas revenue increased significantly from the prior quarter primarily due to a full quarter of production from the Arrangement and recovery of crude oil prices. Net loss of $21.3 million in the first quarter of 2019 was largely the result of non-cash items including an unrealized loss on derivative instruments of $14.5 million and $10.0 million of depletion and depreciation expense.

Fourth quarter 2018 oil and natural gas revenue decreased significantly from the prior quarter due to lower realized oil and natural gas prices as a result of falling benchmark prices, partially offset by higher production. The net loss of $3.5 million in the quarter was attributable to non-cash items including losses on property dispositions of $7.8 million, impairment losses of $5.5 million and $5.1 million of depletion and depreciation expense.

Third quarter 2018 oil and natural gas revenue increased from the prior quarter due to higher production and higher realized oil prices. Higher production was attributable to the successful 2018 drilling program. Realized losses on derivatives incurred in the third, second and first quarters of 2018 were attributed to the continued strengthening in oil prices. The net loss of $2.6 million incurred in the third quarter of 2018 relates to non-cash items including $1.9 million of unrealized losses on derivatives instruments and $8.9 million of depletion and depreciation expense.

Second quarter 2018 oil and natural gas revenue increased from the prior quarter due to higher production and higher realized oil prices. The net loss of $15.1 million incurred in the second quarter of 2018 related 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 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 increased from the previous quarters due to the Company generating higher production volumes which included a full quarter of production from the Red Earth Acquisition and incremental volumes from the plan of arrangement with Arsenal. The quarter also had the improved blended realized prices due to strengthening commodity prices, as well as a higher liquid weighting in the quarter compared to the previous quarters. Net income in the second quarter of 2017 incorporated non-cash unrealized gains of $4.5 million on derivative instruments.

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, 2019 to March 31, 2019 that have materially affected or are reasonably likely to materially affect the Company's internal controls over financial reporting.

Limitation on Design

Management has limited the scope of the design of the Company's disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR") to exclude the controls, policies and procedures of Marquee, which was acquired by PPR on November 21, 2018. The Marquee operations have been included in the consolidated financial statements of PPR since November 21, 2018. However, PPR and its certifying officers have not had sufficient time to appropriately assess the DC&P and ICFR previously used by Marquee and integrate them with those of PPR. The scope limitation is permitted under National Instrument 52-109, which allows an issuer to limit its design of DC&P and ICFR to exclude the controls, policies and procedures of a business acquired not more than 365 days before the end of the financial period to which the above conclusions relate.

During the three months ended March 31, 2019, the Marquee business contributed revenues, net of royalties, of $5.7 million to PPR's consolidated revenues.

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, 2019 described below related to the adoption of new accounting pronouncements.

Effective January 1, 2019, the Company adopted IFRS 16 – *Leases* ("IFRS 16") which replaces IAS 17 – *Leases*. The standard has been applied using the modified retrospective approach and applying certain practical expedients available upon transition. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Further information on the changes to accounting policies can be found in Note 3 to the Interim Financial Statements.

The are no new or amended accounting standards and pronouncements issued are applicable to PPR in future periods.

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 2019. Additional risks are provided in the "Risk Factors" section of the 2018 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 flow-through share premium, the current portion of derivative instruments, the current portion of decommissioning liabilities and the warrant liability. 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, 2019	December 31, 2018
Current assets	21,841	24,834
Less current derivative instrument assets	—	(5,768)
Current assets excluding current derivatives instruments	21,841	19,066
Current liabilities	37,167	41,047
Less flow-through share premium	(281)	(332)
Less current derivative instrument liabilities	(5,144)	—
Less current portion of decommissioning liability	(1,700)	(4,700)
Less warrant liability	(513)	(810)
Current liabilities excluding current flow-through share premium, current leases, current derivatives instruments, current portion of decommissioning liabilities and current warrant liability	29,529	35,205
Working capital (deficit)	(7,688)	(16,139)

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 Flow

Adjusted Funds Flow is calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs, restructuring costs, and other non-recurring items. Management believes that such a measure provides an insightful assessment of PPR's operational 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 Flow 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 flow per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings per share.

Note that in this MD&A, PPR has restated prior period Adjusted Funds Flow to include decommissioning settlements that were previously excluded from the calculation. This adjustment was made in order to meet regulatory requirements. The revised Adjusted Funds Flow numbers incorporate more seasonal variability into previously disclosed numbers as a significant portion of PPR's decommissioning settlements incurred in the last few years has been in winter access only areas, with considerably higher spend incurred in the winter months.

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

	Three Months Ended March 31	
($000s)	**2019**	2018
Cash flow from operating activities	**(6,893)**	3,375
Changes in non-cash working capital	**7,704**	(391)
Other	**(15)**	19
Transaction, restructuring and other costs	**452**	219
Adjusted Funds Flow	**1,248**	3,222

Bank Adjusted EBITDAX

The Company monitors its capital structure and liquidity based on the ratio of Debt to Bank 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 Revolving Facility and Subordinated Notes (for the periods prior to October 31, 2017, the "Amended Credit Facility"). "Bank 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. 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 net income. For purposes of calculating covenants under long-term debt, Bank Adjusted EBITDAX is determined using financial information from the most recent four consecutive fiscal quarters.

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

	Three Months Ended March 31	
($000s)	**2019**	2018
Net earnings (loss) before income tax	**(21,311)**	(11,770)
Add (deduct):		
Interest	**3,432**	1,600
Depletion and depreciation	**9,294**	7,416
Depreciation on right-of-use assets	**686**	—
Exploration and evaluation expense	**96**	147
Unrealized loss (gain) on derivative instruments	**14,509**	5,199
Accretion	**869**	564
Loss (gain) on foreign exchange	**(1,401)**	1,553
Share – based compensation	**112**	164
Gain on sale of properties	**(70)**	—
Gain on warrant liability	**(297)**	(70)
Transaction costs, reorganization and other costs[1]	**452**	219
Bank Adjusted EBITDAX	**6,371**	5,022

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

Net Capital Expenditures

Net capital expenditures is a non-IFRS measure commonly used in the oil and gas industry. The measurement assists management and investors to measure PPR's investment in the Company's existing asset base.

Net capital expenditures is calculated by taking total capital expenditures, which is the sum of property and equipment and exploration and evaluation expenditures from the Consolidated Statement of Cash Flows, plus capitalized stock-based compensation, plus acquisitions from business combinations, which is the outflow cash consideration paid to acquire oil and gas properties, less asset dispositions (net of acquisitions), which is the cash proceeds from the disposition of producing properties and undeveloped lands.