Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three and Nine Months Ended September 30, 2019

Dated: November 12, 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 and nine months ended September 30, 2019. This MD&A is dated November 12, 2019 and should be read in conjunction with the unaudited condensed interim consolidated financial statements for the three and nine months ended September 30, 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") dated March 27, 2019. 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 ("IASB").

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

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

Abbreviations

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

bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousands of barrels of oil equivalent
mmboe	millions of barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
mmbtu	million British Thermal Units
GJ	gigajoule
AECO	AECO "C" hub price index for Alberta natural gas
CGU	cash-generating-unit
DD&A	depreciation, depletion and amortization
E&E	exploration and evaluation
GAAP	generally accepted accounting principles
G&A	general and administrative
P&D	production and development
PSU	performance share unit
DSU	deferred restricted share unit
RSU	restricted share unit
WTI	West Texas Intermediate
USD	U.S. dollars
CAD	Canadian dollars
US	United States
CDN	Canadian

Financial and Operational Summary

($000s except per unit amounts)	Three Months Ended September 30, 2019	2018	Nine Months Ended September 30, 2019	2018
Production Volumes				
Crude oil (bbl/d)	**4,029**	4,044	**4,051**	3,552
Natural gas (Mcf/d)	**12,092**	9,607	**11,792**	9,056
Natural gas liquids (bbl/d)	**169**	131	**172**	120
Total (boe/d)	**6,214**	5,776	**6,188**	5,181
% Liquids	**68 %**	72 %	**68 %**	71 %
Average Realized Prices				
Crude oil ($/bbl)	**61.83**	69.83	**61.81**	67.84
Natural gas ($/Mcf)	**1.14**	1.35	**1.57**	1.53
Natural gas liquids ($/bbl)	**25.53**	52.61	**30.26**	52.66
Total ($/boe)	**43.01**	52.33	**44.29**	50.40
Operating Netback ($/boe)[1]				
Realized price	**43.01**	52.33	**44.29**	50.40
Royalties	**(4.85)**	(9.04)	**(4.57)**	(7.89)
Operating costs	**(18.92)**	(18.81)	**(20.86)**	(19.47)
Operating netback	**19.24**	24.48	**18.86**	23.04
Realized losses on derivatives	**(0.29)**	(6.77)	**(1.02)**	(5.48)
Operating netback, after realized losses on derivatives	**18.95**	17.71	**17.84**	17.56

Third quarter 2019 highlights include:

- Production averaged 6,214 boe/d (68% liquids) for the third quarter of 2019, an 8% increase from the same period in 2018 driven by the Marquee acquisition and PPR's successful Q4 2018 – 2019 development program, partially offset by natural declines.
- Operating netback[1] before the impact of derivatives was $11.0 million ($19.24/boe) for the quarter, 15% lower than the third quarter of 2018 primarily due to lower realized commodity prices, partially offset by higher production. Operating netback, after realized loss on derivatives, was $10.8 million ($18.95/boe) for the third quarter of 2019, a 15% increase from the same period in 2018 primarily due to lower realized losses on derivatives.
- Operating expense was $18.92/boe for the third quarter, at the low end of our guidance. Compared to the first and second quarters of 2019, operating expense improved by $4.55/boe and $1.44/boe, respectively. While the first quarter 2019 operating expense was negatively impacted by extreme weather, the third quarter operating expense level was more reflective of PPR's expected run-rate.
- Adjusted funds flow ("AFF")[1], excluding $0.4 million of decommissioning settlements, was $6.6 million ($0.04 per basic and diluted share) for the third quarter of 2019, a 7% increase from the same quarter in 2018 due to higher production and an improved operating netback, after realized losses on derivatives.
- Net loss totaled $2.3 million in the third quarter of 2019 compared to a net loss of $2.6 million in the same period last year, primarily driven by non-cash items.

[1] Operating netback and AFF are non-IFRS measures and are defined below under "Other Advisories".

- Exited the third quarter with positive working capital[1] of $2.7 million (December 31, 2018 – deficit of $16.1 million), including cash and restricted cash of $6.1 million, primarily due to paying down accounts payable and accrued liabilities with AFFs and debt borrowing, combined with an increase in accrued revenue at higher oil prices.

- As at September 30, 2019, net debt[1] totaled $112.1 million, a decrease of $1.3 million and $5.2 million from June 30, 2019 and December 31, 2018, respectively. The decreases were attributable to the excess of AFF over net capital expenditures, partially offset by weakening of the Canadian dollar against the US dollar.

- With the volatility in both West Texas Intermediate and Canadian oil price differentials, the Company elected to take a defensive approach in the first nine months of 2019 by reducing capital spending compared to the prior year with a focus on strengthening the balance sheet. Net capital expenditures[1] during the third quarter of 2019 were $1.9 million, primarily directed to recompleting one well in the Provost area, facility work at Evi and a 3D seismic program in the Princess area. The Company is currently drilling one development well and one stratigraphic well in the Princess area.

- During the third quarter PPR satisfied its remaining $1.8 million of Canadian Exploration Expense ("CEE") expenditure commitment related to its October 11, 2018 flow-through share issuance and related over-allotment.

- At Evi, an independent reserves evaluation as of May 31, 2019 assigned an incremental 2.1 MMboe of proved plus probable ("P+P") undeveloped reserves (97% oil and liquids) to future waterflood expansions, comprised of approximately 1.6 MMboe of proved undeveloped reserves and approximately 0.5 MMboe of probable undeveloped reserves, with a total estimated net present value of future net revenue (before tax and discounted at 10%) on a P+P basis of $30 million.[2] The incremental reserves assignments increased PPR's total estimated corporate reserves volumes by 7.1% on a proved basis and by 6.1% on a P+P basis, relative to year-end estimates.

- Subsequent to September 30, 2019, PPR's lenders confirmed continuation of the borrowing base under the senior secured revolving note facility ("Revolving Facility") at US$60.0 million, extended the maturity date of the Revolving Facility from October 31, 2020 to April 30, 2021, and removed the "term-out" feature so as to keep the facility as a revolving facility for the remainder of the term. Financial covenants are unchanged. The next borrowing base re-determination for the Revolving Facility will be on or about March 31, 2020.

- As of September 30, 2019, PPR had US$58.0 million of borrowings drawn against the US$60.0 million Revolving Facility, comprised of US$30.0 (CAN$40.5 million equivalent using exchange rate at the time of borrowing) of CAD-denominated borrowing and US$28.0 million of USD-denominated borrowing (CAN$37.1 million equivalent using the September 30, 2019 exchange rate of $1.00 USD to $1.32 CAD). There were also US$30.6 million (CAN$40.6 million equivalent using the September 30, 2019 exchange rate) of senior subordinated notes (defined herein) due October 31, 2021 outstanding at the quarter-end, for total borrowings of US$88.6 million or CAN$117.4 million at the September 30, 2019 exchange rate. The increase in borrowings from year-end 2018 was largely used to reduce working capital deficit.

Year-to-date corporate highlights include:

- In April 2019, PPR's lenders 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, PPR's financial covenants would be well in line with the original thresholds.

- 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.

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[1] Working capital (deficit), net debt and net capital expenditures are non-IFRS measures and are defined below under "Other Advisories".

[2] The incremental reserves assignments are based on an independent reserves evaluation of the Company's interests in respect of specific reserve entities within three future undeveloped waterflood expansion areas in Evi. The evaluation was conducted by Sproule Associates Limited ("Sproule"), independent qualified reserves evaluators, with an effective date of May 31, 2019, and supplements Sproule's year-end evaluation of the Company's total corporate reserves as at December 31, 2018. For additional details, please refer to the Company's news release dated September 18, 2019 (available at www.ppr.ca) and related material change report dated September 18, 2019 (filed on SEDAR and available under PPR's issuer profile at www.sedar.com).

Outlook

With a continued focus on its balance sheet and enhancing per share metrics, PPR's capital allocation decisions will be regularly assessed as the Company continues to responsibly manage its inventory of high-quality future drilling locations. Supported by a successful 2019 development program and strong adjusted funds flow generated year-to-date, Prairie Provident's disciplined 2019 capital budget of $14.2 million is expected to be funded with internally-generated AFF. Due to recent widening of WCS differentials, the Company has decided to defer the drilling of one well to the first quarter of 2020 to preserve liquidity and development economics. As such, the Company expects its average full-year production to be at the low end of its 2019 guidance.

PPR will continuously review, and as needed adjust, the capital budget considering commodity prices, economics and market opportunities. The Company remains focused on responsibly managing its inventory of high-quality drilling opportunities, capital spending and decommissioning obligations, while seeking to enhance per share production, reserves, and AFF for shareholders.

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 September 30,		Nine Months Ended September 30,	
	2019	2018	**2019**	2018
Crude oil (bbls/d)	**4,029**	4,044	**4,051**	3,552
Natural gas (Mcf/d)	**12,092**	9,607	**11,792**	9,056
Natural gas liquids (bbls/d)	**169**	131	**172**	120
Total (boe/d)	**6,214**	5,776	**6,188**	5,181
Liquids Weighting	**68 %**	72 %	**68 %**	71 %

Average production for the three and nine months ended September 30, 2019 was 6,214 boe/d (68% liquids) and 6,188 boe/d (68% liquids), an increase of 8% and 19%, respectively, compared to the corresponding periods in 2018. Production increase was driven by PPR's successful Q4 2018 and 2019 development program and incremental production volumes from the Marquee acquisition completed in Q4 2018, partially offset by natural declines. In the first nine months of 2019, production was impacted by cold weather-related outage of approximately 400 boe/d during the first quarter of 2019 and the shut-in of 200 boe/d of natural gas-weighted production and natural declines. In the second quarter of 2019, the Company fully resumed the 400 boe/d of downtime production caused by cold weather, while the 200 boe/d of natural gas-weighted shut-in production remains offline.

During the first quarter of 2019, PPR completed and tied in two Slave Point wells drilled in the EVI area in late 2018. The wells commenced production in late February 2019. Combined production from the two wells averaged 207 boe/d (94% liquids weighting) and 210 boe/d (94% liquids weighting) for the three and nine months ended September 30, 2019. During the second quarter of 2019, PPR's most recent well in southern Princess was drilled and brought on production on June 18, 2019. Production from the well averaged 386 boe/d (37% liquids weighting) and 190 boe/d (37% liquids weighting) for the three and nine months ended September 30, 2019. No new wells were drilled during the third quarter of 2019.

Revenue

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per unit amounts)	**2019**	2018	**2019**	2018
Revenue				
Crude oil	**22,919**	25,979	**68,354**	65,781
Natural gas	**1,273**	1,197	**5,040**	3,774
Natural gas liquids	**397**	634	**1,421**	1,725
Oil and natural gas revenue	**24,589**	27,810	**74,815**	71,280
Average Realized Prices				
Crude oil ($/bbl)	**61.83**	69.83	**61.81**	67.84
Natural gas ($/Mcf)	**1.14**	1.35	**1.57**	1.53
Natural gas liquids ($/bbl)	**25.53**	52.61	**30.26**	52.66
Total ($/boe)	**43.01**	52.33	**44.29**	50.40
Benchmark Prices				
Crude oil - WTI ($/bbl)	**74.59**	90.84	**75.90**	86.07
Crude oil - Edmonton Light Sweet ($/bbl)	**67.87**	81.69	**69.14**	78.03
Natural gas - AECO monthly index-7A ($/Mcf)	**1.00**	1.35	**1.37**	1.40
Natural gas - AECO daily index - 5A ($/Mcf)	**0.89**	1.19	**1.50**	1.49
Exchange rate - US$/CDN$	**0.76**	0.77	**0.75**	0.78

PPR's third quarter 2019 revenue decreased by 12% or $3.2 million from the third quarter of 2018. Crude oil revenue for the third quarter of 2019 decreased by 12%, primarily due to a 11% reduction in realized crude oil prices and a nominal decrease in crude oil production volumes. PPR's product prices generally correlate to changes in the benchmark prices. In the third quarter of 2019, the average WTI price and the average Edmonton Light Sweet price decreased by 18% and 17%, respectively. Partially mitigating the decreases in benchmark prices were the narrowing of Western Canadian Select price differentials from WTI and lower pipeline apportionment charges. Third quarter 2019 natural gas revenue increased by 6% or $0.1 million, compared to the same quarter in 2018, reflecting a 26% increase in production volumes, partially offset by an 16% decrease in realized natural gas prices.

Average realized prices per boe for the third quarter of 2019 decreased by 18% or $9.32/boe from the same quarter of 2018, correlating to the decreases in the underlying crude oil, natural gas and natural gas liquids realized prices. A decrease in the liquids-weighted production mix from 72% to 68% in the third quarter of 2019 further contributed to the decrease.

On a year-to-date basis, revenue increased by 5% or $3.5 million, compared to the same period in 2018. The 4% increase in crude oil revenue reflected a 14% rise in oil production volumes, partially offset by a 9% decline in realized crude oil prices. For the nine months ended September 30, 2019, the average WTI price and the average Edmonton Light Sweet price both decreased by 12% and 11%, respectively, compared to the same period of 2018. The 34% increase in natural gas revenue reflected a 30% production increase, accompanied by a 3% increase in realized natural gas prices.

Averaged realized prices per boe for the nine months ended September 30, 2019 decreased by 12% or $6.11/boe, compared to the same period in 2018, resulting from lower crude oil and NGL realized prices. A decrease in the liquids-weighted production mix from 71% to 68% for the nine months ended September 30, 2019 further contributed to the decrease.

Royalties

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2019**	2018	**2019**	2018
Royalties	**2,770**	4,806	**7,719**	11,158
Per boe	**4.85**	9.04	**4.57**	7.89
Percentage of revenue	**11.3 %**	17.3 %	**10.3 %**	15.7 %

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 and nine months ended September 30, 2019 decreased compared to the corresponding periods in 2018. For the three months ended September 30, 2019, the decrease was due to a decrease in production for the Princess and Wheatland areas of 31% and 53%, respectively, and an overall decline in average realized price of 18%, compared to the same period in 2018. The year-to-date decrease in royalties as a percent of revenue was a result of a 52% production decrease in the Wheatland area, favorable gas cost allowance deductions and an 12% decrease in the overall average realized price, compared to the same period in 2018. Production in the Princess and Wheatland areas is subject to flat freehold royalty rates (range: 15% - 21%), 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 September 30,		Nine Months Ended September 30,	
($000s)	**2019**	2018	**2019**	2018
Realized loss on derivatives	**(167)**	(3,596)	**(1,721)**	(7,751)
Unrealized gain (loss) on derivatives	**5,194**	(1,884)	**(3,999)**	(16,399)
Total gain (loss) on derivatives	**5,027**	(5,480)	**(5,720)**	(24,150)

Per boe				
Realized loss on derivatives	**(0.29)**	(6.77)	**(1.02)**	(5.48)
Unrealized gain (loss) on derivatives	**9.09**	(3.55)	**(2.37)**	(11.59)
Total gain (loss) on derivatives	**8.80**	(10.32)	**(3.39)**	(17.07)

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 unrealized gain on derivatives recognized for the three months ended September 30, 2019 is primarily related to a decline in WTI futures pricing as at September 30, 2019.

The decrease in the unrealized loss on derivatives recognized for the nine months ended September 30, 2019 is primarily due to a decrease in WTI futures pricing and a further appreciation of the Canadian dollar against the US dollar as at September 30, 2019, as compared to the same period in 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 predominantly in US dollars to maintain such economic hedges.

As at September 30, 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				
October 1, 2019 – December 31, 2019	CDN$ WTI	150		$64.39
October 1, 2019 – December 31, 2019	US$ WTI	500		$52.50
October 1, 2019 – December 31, 2019	US$ WTI	600		$60.05
October 1, 2019 -December 1, 2019	US$ WTI	450		$52.00
January 1, 2020 - March 31, 2020	US$ WTI	450		$51.50
January 1, 2020 - June 30, 2020	US$ WTI	800		$55.10
April 1, 2020 - June 30, 2020	US$ 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		$55.00
Crude Oil Sold Call Options				
October 1, 2019 – December 31, 2019	CDN$ WTI	400		$85.00
January 1, 2020 – December 31, 2020	US$ WTI	400		$60.50
Crude Oil Put Options				
October 1, 2019 – December 31, 2019	US$ WTI	450	$6.29	$55.00
January 1, 2020 - March 31, 2020	CDN$ WTI	400	$3.65	$56.05
April 1, 2020 - June 30, 2020	CDN$ WTI	300	$6.00	$71.30
Crude Oil Collars				
October 1, 2019 – December 31, 2019	US$ WTI	400		$52.50/60.00
October 1, 2019 – December 31, 2019	US$ WTI	275		$50.00/57.00
October 1, 2019 – December 31, 2019	US$ WTI	300		$50.00/60.00
October 1, 2019 – December 31, 2019	US$ WTI	150		$52.50/63.10
January 1, 2020 – December 31, 2020	US$ WTI	175		$49.00/ 54.75
July 1, 2020 - December 31, 2020	US$ WTI	500		$50.00/59.00
Crude Oil Three-way Collars				
January 1, 2020 – March 31, 2020	US$ WTI	400		$42.50/52.50/65.00
January 1, 2020 – March 31, 2020	US$ WTI	300		$45.00/55.00/66.15
January 1, 2021 – March 31, 2021	US$ WTI	200		$45.50/52.50/65.00
January 1, 2021 – December 31, 2021	US$ WTI	650		$40.00/50.00/64.25

Remaining Term	Reference	Total Daily Volume (GJ)	Premium/ GJ	Weighted Average Price/GJ
Natural Gas Swaps				
October 1, 2019 – December 31, 2019	US$ NYMEX	3,000		$3.15
October 1, 2019 - October 31, 2019	US$ NYMEX	1,800		$2.70
October 1, 2019 – December 31, 2019	US$ NYMEX	1,420		$2.70
Natural Gas Put Options				
January 1, 2020 - March 30, 2020	AECO 7A Monthly Index	4,000	$0.15	$1.16
April 1, 2020 - June 30, 2020	AECO 7A Monthly Index	4,600	$0.25	$1.11

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

Operating Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2019**	2018	**2019**	2018
Lease operating expense	**8,335**	7,209	**26,911**	20,500
Transportation and processing	**970**	1,709	**3,650**	4,398
Production and property taxes	**1,512**	1,076	**4,680**	2,635
Total operating expenses	**10,817**	9,994	**35,241**	27,533
Per boe	**18.92**	18.81	**20.86**	19.47

During the three and nine months ended September 30, 2019, lease operating expenses increased by 16% or $1.1 million and 31% or $6.4 million respectively, from the corresponding periods in 2018. The increases were primarily the result of higher production volumes.

Transportation and processing expense for the three and nine months ended September 30, 2019 both decreased by $0.7 million, as compared to the same periods in 2018. The decrease of $0.7 million for both the three and nine months ended September 30, 2019 was primarily due to decreased natural gas production in the Wheatland area, resulting in lower third-party natural gas processing and natural gas transportation costs.

Production and property tax expense for the three and nine months ended September 30, 2019 increased by 41% or $0.4 million and 78% or$2.0 million, respectively, compared to the same periods in 2018. The increase primarily related to the properties acquired from the Arrangement and freehold mineral taxes associated with new wells in the Princess area.

On a per boe basis, total operating expense for the three and nine months ended September 30, 2019 increased by 1% or $0.11/ boe and 7% or $1.39/boe, respectively, compared to the same periods in 2018. The increases were largely due to higher property taxes per boe for properties acquired through the Arrangement and higher maintenance costs incurred in the first quarter of 2019 due to extreme cold weather, partially offset by lower third-party transportation and processing fees.

Operating Netback

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ per boe)	**2019**	2018	**2019**	2018
Revenue	**43.01**	52.33	**44.29**	50.40
Royalties	**(4.85)**	(9.04)	**(4.57)**	(7.89)
Operating costs	**(18.92)**	(18.81)	**(20.86)**	(19.47)
Operating netback	**19.24**	24.48	**18.86**	23.04
Realized losses on derivatives	**(0.29)**	(6.77)	**(1.02)**	(5.48)
Operating netback, after realized losses on derivatives	**18.95**	17.71	**17.84**	17.56

PPR's operating netback after realized losses on derivatives was $18.95/boe and $17.84/boe for the three and nine months ended September 30, 2019, which represents an increase of $1.24/boe and $0.28/boe, respectively, compared with the corresponding periods of 2018.

For the three months ended September 30, 2019, the operating netback increase was due to a decrease in realized losses on derivatives by $6.48/boe and royalties by $4.19/boe, partially offset by decreased average realized prices by $9.32/boe and increased operating expenses by $0.11/boe, compared to the corresponding three month period in 2018.

For the nine months ended September 30, 2019, the operating netback increase was due to a decrease in realized losses on derivatives by $4.46/boe and royalties by $3.32/boe, respectively, partially offset by a $6.11/boe reduction in average realized prices and a $1.39/boe increase in operating expenses, compared to the corresponding nine month period in 2018.

General and Administrative Expenses ("G&A")

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2019**	2018	**2019**	2018
Gross cash G&A expenses	**2,154**	2,267	**6,926**	7,417
Gross share-based compensation expense	**192**	245	**610**	706
Less amounts capitalized	**(392)**	(342)	**(1,234)**	(1,417)
Net G&A expenses	**1,954**	2,170	**6,302**	6,706
Per boe	**3.42**	4.08	**3.73**	4.74

Despite increased production for the three and nine months ended September 30, 2019, gross cash G&A decreased by $0.1 million and $0.5 million, or 5% and 7%, respectively, compared to the same periods 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.

Gross stock-based compensation decreased by 22% and 14% for the three and nine months ended September 30, 2019, respectively, compared with the same periods in 2018. These decreases corresponded with the lower fair value of new grants.

Finance Costs

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2019**	2018	**2019**	2018
Interest expense	**2,892**	1,594	**8,466**	4,473
Amortization of financing costs	**408**	231	**1,176**	668
Non-cash interest on financing lease	**247**	—	**797**	—
Non-cash interest on warrant liabilities	**92**	26	**259**	73
Accretion – decommissioning liabilities	**809**	526	**2,473**	1,596
Accretion – other liabilities	**8**	32	**73**	93
Total finance cost	**4,456**	2,409	**13,244**	6,903
Interest expense per boe	**5.06**	3.00	**5.01**	3.16
Non-cash interest and accretion expense per boe	**2.74**	1.53	**2.83**	1.72

Interest expense is primarily comprised of interest incurred related to the Company's outstanding borrowings. The increase in interest expense of $1.3 million and $4.0 million for the three and nine months ended September 30, 2019 as compared to the respective periods in 2018 related to increased average borrowings and higher effective interest rates on the Company's Revolving Facility.

Of the $2.9 million and $8.5 million of interest expense incurred in the three and nine months ended September 30, 2019, $0.5 million and $1.5 million, respectively, was deferred interest on the Senior Notes which will be repaid upon maturity (see Subordinated Senior Notes section below). The weighted average effective interest rate for the three and nine months ended September 30, 2019 was 9.60% and 9.72%, respectively (2018 – 8.8% and 8.8% respectively).

Accretion – decommissioning liabilities increased by $0.3 million and $0.9 million during the three and nine months ended September 30, 2019, compared to the same period in 2018, due to additional decommissioning liabilities acquired through the Arrangement.

(Loss) Gain on Foreign Exchange

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2019**	2018	**2019**	2018
Realized (loss) gain on foreign exchange	**(58)**	3	**100**	(382)
Unrealized (loss) gain on foreign exchange	**(932)**	1,081	**2,110**	(1,550)
(Loss) Gain on foreign exchange	**(990)**	1,084	**2,210**	(1,932)

Foreign exchange (losses) gains incurred in the three and nine months ended September 30, 2019 related largely to the translation impact on US dollars denominated borrowings (see "Capital Resources and Liquidity" section below).

Exploration and Evaluation Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2019**	2018	**2019**	2018
Exploration and evaluation expense	**223**	46	**536**	292
Per boe	**0.39**	0.09	**0.32**	0.21

Exploration and evaluation expenses are comprised of undeveloped land expiries.

Depletion and Depreciation

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2019**	2018	**2019**	2018
Depletion and depreciation	**10,224**	8,903	**30,004**	24,578
Depreciation on right-of-use assets	**686**	—	**2,058**	—
Total depletion expense	**10,910**	8,903	**32,062**	24,578
Per boe	**19.08**	16.75	**18.98**	17.38

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 nine months 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 three and nine months ended September 30, 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, no depreciation was recognized on right-of-use assets for the three and nine months ended September 30, 2018.

Impairment Recovery

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2019**	2018	**2019**	2018
P&D Impairment – decommissioning asset	**—**	—	**—**	(162)
Total impairment recovery	**—**	—	**—**	(162)

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

Net Loss

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s except per share)	**2019**	2018	**2019**	2018
Net earnings (loss)	**(2,320)**	(2,627)	**(20,345)**	(29,433)
Per share – basic	**(0.01)**	(0.02)	**(0.12)**	(0.25)
Per share – diluted	**(0.01)**	(0.02)	**(0.12)**	(0.25)

Net loss for the third quarter of 2019 was $2.3 million, compared to a net loss of $2.6 million in the same quarter of 2018. The $0.3 million decrease in net loss was primarily due to non-cash, including a $7.1 million decrease in unrealized derivative losses due to changes in the marked-to-market value of open derivative contracts, partially offset by a $2.0 million increase in depletion, depreciation and amortization, a $2.9 million decrease in gain on disposition and a $2.1 million increase in unrealized foreign exchange loss.

Net loss was $20.3 million for the first nine months of 2019, compared to a net loss of $29.4 million in the same period of 2018. The $9.1 million decrease in net loss was primarily due to non-cash, including $12.4 million decrease in unrealized derivative losses due to changes in the marked-to-market value of open derivative contracts, a $4.1 million increase in unrealized foreign exchange gain, and a $3.3 million reduction in other liabilities, partially offset by $7.5 million increase in depletion, depreciation and amortization and a $2.9 million decrease in gain on disposition.

Net Capital Expenditures[1,2]

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2019**	2018	**2019**	2018
Drilling and completion	**72**	1,129	**4,311**	12,889
Equipment, facilities and pipelines	**419**	1,041	**1,277**	6,423
Land and seismic	**1,053**	166	**2,234**	779
Capitalized overhead and other	**351**	562	**1,028**	1,673
Total Capital expenditures	**1,895**	2,898	**8,850**	21,764
Acquisitions – business combination	**—**	—	**—**	887
Asset dispositions (net of acquisitions)	**(14)**	(2,789)	**(92)**	(2,836)
Net Capital Expenditures	**1,881**	109	**8,758**	19,815

[1] Net Capital expenditures include expenditures on E&E assets.
[2] Net capital expenditures are non-IFRS measures and are defined below under "Other Advisories"

Capital expenditures prior to acquisitions or dispositions for the three and nine months ended September 30, 2019 were $1.9 million and $8.9 million, respectively. The Company focused its capital activities during the first nine months of 2019 in the Evi and Princess areas. In Evi, the Company incurred $2.8 million during the first quarter of 2019 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. During the second quarter of 2019, PPR's most recent well in southern Princess was completed and brought on production mid-June 2019. The Company incurred total capital expenditures of $1.6 million to drill, complete, equip and tie-in this new well. Further, PPR acquired undeveloped lands and mineral rights in the Wayne area. During the third quarter of 2019, the Company recompleted one well in the Provost area, facility work at Evi and spent $0.8 million on 3D seismic in the Princess area.

During the third quarter of 2018, PPR completed, equipped and tied-in two gross (2.0 net) wells in the Princess area that were drilled late in the second quarter of 2018, including pipeline construction. PPR's 2018 year-to-date capital activities included the drilling, completion, equip and tie-in of five gross (5.0 net) wells in the Princess area and three gross (3.0 net) wells in the Wheatland area, construction of pipelines and a multi-well satellite in Princess and the expansion of the Evi waterflood project with the conversion of three producing wells into injector wells. Capital expenditures for the first nine months of 2018 also included $0.9 million for the acquisition of oil and natural gas properties and infrastructure in the Princess area in the first quarter of 2018. In the third quarter of 2018, PPR disposed of certain non-core gas weighted properties for cash proceeds of $2.8 million. The disposed properties had production of approximately 60 boe/d and were cash flow neutral.

Decommissioning Liabilities

PPR's decommissioning liabilities at September 30, 2019 were $143.7 million (December 31, 2018 - $148.5 million) to provide for future remediation, abandonment and reclamation of PPR's oil and gas properties. The decrease of $4.8 million from year-end 2018 was due to settlements of decommissioning obligations totaling $3.7 million, changes in cost estimates of $3.4 million related to the properties acquired from the Arrangement, partially offset by $2.5 million of accretion of decommissioning liabilities.

Capital Resources and Liquidity

Capital Resources

Working Capital

At September 30, 2019, the Company had positive working capital (as defined in "Other Advisories" below) of $2.7 million (December 31, 2018 – $16.1 million deficit). The improvement in working capital from December 31, 2018 was primarily the result of paying down accounts payable and accrued liabilities with AFFs and debt borrowing, combined with increase in accrued revenue at higher oil prices.

Revolving Facility

Subsequent to September 30, 2019, PPR confirmed continuation of the borrowing base under the Revolving Facility at US$60.0 million, extended the maturity date of the Revolving Facility from October 31, 2020 to April 30, 2021, and removed the "term out" feature so as to keep the facility as a revolving facility for the remainder of the term. Financial covenants are unchanged. The next borrowing base re-determination date will be on or about March 31, 2020.

The Revolving Facility provides a borrowing base of US$60.0 million. It is denominated in USD, but accommodates CAD advances up to the lesser of CAN$54 million or US$30 million. As of September 30, 2019, PPR had US$58.0 million (December 31, 2018 – US$49.0 million) of borrowings drawn against the US$60.0 million Revolving Facility, including US$30.0 (CAN$40.5 million equivalent using exchange rate at the time of borrowing) (December 31, 2018 – US$30.0 million or CAN$40.5 million) of CAD denominated borrowing and US$28.0 million (CAN$37.1 million equivalent using the September 30, 2019 exchange rate of $1.00 USD to $1.32 CAD) (December 31, 2018 – US$19.0 million or CAN$25.9 million using the December 31, 2018 exchange rate of $1.00USD to $1.36CAD) of USD denominated borrowing. The increase in borrowings from year-end 2018 was largely used to reduce working capital deficit. 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. If a borrowing base deficiency exists because of a re-determination, the lender is required to notify the Company of such shortfall. The Company may repay the shortfall amount by either making one installment within 90 days or six equal consecutive monthly installments beginning within 30 days after the Company's receipt of the borrowing base deficiency notice.

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 September 30, 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 September 30, 2019, $1.4 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 October 31, 2017 the Company issued US$16.0 million Senior Notes (CAN$21.2 million using the September 30, 2019 month end exchange rate of $1.00 USD to $1.32 CAD) due October 31, 2021. In addition, upon closing of the Arrangement on November 21, 2018, PPR issued an additional US$12.5 million (CAN$16.6 million using the September 30, 2019 month end exchange rate of $1.00 USD to $1.32 CAD) of Senior Notes. Senior Notes outstanding as at September 30, 2019 totaled US$28.5 million (CAN$37.7 million using the September 30, 2019 month end exchange rate of $1.00 USD to $1.32 CAD). 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. As at September 30, 2019, US$2.1 million (CAN$2.8 million using the September 30, 2019 month end exchange rate of $1.00 USD to $1.32 CAD) of interests were deferred and will be repaid upon maturity of the Senior Notes.

In conjunction with the issuances of the Senior Notes, the Company issued a total of 8,318,000 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 September 30, 2019 was $0.1 million.

As at September 30, 2019, $1.0 million of deferred costs related to PPR's Senior Notes was netted against its carrying value (December 31, 2018 – $1.2 million).

Covenants

During the second quarter of 2019, PPR 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 September 30, 2019 are as follows:

Financial Covenant	Revolving Facility Requirement	Senior Note Requirement	As at September 30, 2019
Total Leverage – adjusted indebtedness to EBITDAX	Cannot Exceed 4.75 to 1.0	Cannot Exceed 5.00 to 1.00	4.7 to 1.0
Senior Leverage – senior adjusted indebtedness to EBITDAX	Cannot Exceed 3.25 to 1.0	Cannot Exceed 3.50 to 1.0	3.0 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 1.2 to 1.0	Cannot be less than 1.2 to 1.0	1.2 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	1.4 to 1.0

The Company was in compliance with all covenants as at September 30, 2019.

Shareholders' Equity

At September 30, 2019, PPR had consolidated share capital of $135.7 million (December 31, 2018 – $136.1 million) and had 171.3 million (December 31, 2018 – 171.9 million) outstanding common shares. The Company also had 4.8 million (December 31, 2018 – 8.0 million) warrants outstanding from a bought deal financing and a private placement completed in October 2018 .

In the first quarter of 2019, the Company granted 2.4 million restricted share units ("RSUs") to officers and employees. RSUs vest evenly over a three-year period. As at September 30, 2019, 3.2 million (December 31, 2018 – 1.6 million) RSUs were outstanding. In addition, the Company issued 0.5 million 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 September 30, 2019, 1.2 million (December 31, 2018 – 0.6 million) 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 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 September 30, 2019, there were 0.3 million (December 31, 2018 – 0.3 million) PSUs outstanding and 4.1 million (December 31, 2018 – 2.2 million) options with a weighted average strike price of $0.48 per share, of which 1.4 million were exercisable at a weighted average strike price of $0.82 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.

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.

During the three months ended September 30, 2019, the Company did not repurchase any common shares. During the nine months ended September 30, 2019, the Company repurchased and cancelled a total of 643,130 common shares.

As of the date of this MD&A, there are 171.3 million common shares, 3.2 million RSUs, 4.0 million stock options, 0.3 million PSUs, 1.2 million DSUs, 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, AFF 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 AFF. Value-creating activities may be financed with a combination of AFF and other sources of capital. The Company has determined that its current financial obligations, including current commitments are adequately funded from the available borrowing capacity and from AFF.

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 September 30, 2019 was 4.7 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 nine months of 2019 and as such, operating netbacks have improved from the fourth quarter of 2018. PPR's management believes that with its 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 September 30, 2019, PPR has fully met its remaining $1.8 million of CEE costs commitment related to the October 11, 2018 flow-through share issuance and related over allotment.

Supplemental Information

Financial – Quarterly extracted information

($000 except per unit amounts)	2019 Q3	2019 Q2	2019 Q1	2018 Q4	2018 Q3	2018 Q2	2018 Q1	2017 Q4
Production Volumes								
Crude oil (bbl/d)	4,029	4,230	3,892	4,042	4,044	3,513	3,089	3,233
Natural gas (Mcf/d)	12,092	11,709	11,568	10,523	9,607	9,175	8,373	9,200
Natural gas liquids (bbl/d)	169	204	142	141	131	104	124	106
Total (boe/d)	6,214	6,386	5,962	5,937	5,776	5,146	4,609	4,872
% Liquids	68 %	69 %	68 %	70 %	72 %	70 %	70 %	69 %
Financial								
Oil and natural gas revenue	24,589	27,331	22,895	13,542	27,810	24,187	19,283	20,510
Royalties	(2,770)	(3,148)	(1,801)	(1,902)	(4,806)	(3,815)	(2,537)	(2,171)
Unrealized (loss) gain on derivatives	5,194	5,316	(14,509)	26,968	(1,884)	(9,316)	(5,199)	(6,960)
Realized (loss) gain on derivatives	(167)	(1,427)	(127)	(1,269)	(3,596)	(2,943)	(1,212)	851
Revenue net of realized and unrealized (losses) gains on derivatives	26,846	28,072	6,458	37,339	17,524	8,113	10,335	12,230
Net earnings (loss)	(2,320)	3,235	(21,260)	(3,532)	(2,627)	(15,064)	(11,742)	(44,145)
Per share – basic	(0.01)	0.02	(0.12)	(0.02)	(0.02)	(0.13)	(0.10)	(0.38)
Per share – diluted	(0.01)	0.01	(0.12)	(0.02)	(0.02)	(0.13)	(0.10)	(0.38)
AFF [(1)]	6,196	6,321	1,248	(5,346)	5,533	4,625	3,222	5,512
Per share – basic	0.04	0.04	0.01	(0.04)	0.05	0.04	0.03	0.05
Per share – diluted	0.04	0.02	0.01	(0.04)	0.05	0.04	0.03	0.05

[1] AFF 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 its core areas, the Arrangement with Marquee 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. With the exception of the second quarter of 2019, 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 dollar denominated borrowings. The Company has maintained positive AFF in all the quarters, with the exception of the fourth quarter of 2018. Negative funds flow from operations in the fourth quarter of 2018 was the result of negative operating netbacks after realized losses on derivatives caused by significant widening in Canadian oil differentials which resulted in a substantial reduction in realized revenue.

Third quarter 2019 oil and natural gas revenue decreased from the prior quarter primarily due to lower realized oil and natural gas prices as a result of falling benchmark prices. Though the Company realized $6.6 million of AFF (before decommissioning settlements of $0.4 million), a net loss of $2.3 million was recorded in the third quarter of 2019 due to non-cash items including $1.0 million unrealized foreign exchange loss, $2.1 million non-cash finance costs and $10.9 million of depletion and depreciation expense, partially offset by an unrealized gain on derivatives of $5.2 million.

Second quarter 2019 oil and natural gas revenue increased from the prior quarter primarily due to a full quarter of production from the Arrangement, the Company’s successful drilling program and a rise in crude oil prices. Realized losses on derivatives incurred in the second quarter of 2019 was attributed to the strengthening in oil prices. Net earnings of $3.2 million in the second quarter of 2019 was attributable to AFF of $6.6 million (before decommissioning settlements of $0.3 million), partially offset by the aggregate impact from non-cash items including $5.3 million of unrealized gain on derivatives, $1.8 million of unrealized foreign exchange gain, a $3.3 million reduction in other liabilities, $2.1 million of non-cash finance costs and $11.2 million of depletion and depreciation expense.

First quarter 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 derivatives 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 and widened Canadian crude oil differentials, 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 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 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 derivatives 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 derivatives, $8.8 million of depletion and depreciation expense and $3.7 million of E&E expense.

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 September 30, 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 and nine months ended September 30, 2019, the Marquee business contributed revenues, net of royalties, of $5.2 million and $16.6 million, respectively, 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 third 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 excluding the current portion of derivative instruments, less accounts payable and accrued liabilities. 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 and warrant liabilities are excluded as it is a non-monetary liability. Lease liabilities have historically been excluded as they were not recorded on the balance sheet until the adoption of IFRS 16 – Leases on January 1, 2019.

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

($000s)	**September 30, 2019**	December 31, 2018
Current assets	**21,281**	24,834
Less: current derivative instrument assets	**(1,531)**	(5,768)
Current assets excluding current derivatives instruments	**19,750**	19,066
Less: Accounts payable and accrued liabilities	**17,068**	35,205
Working capital (deficit)	**2,682**	(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 derivatives.

Adjusted Funds Flow

AFF 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. AFF 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. AFF 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, AFF 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 AFF, the current calculation results in a correspondingly lower AFF 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 AFF measurement may not be comparable with the calculation of similar measurements used by other companies.

PPR has restated prior period AFF to include decommissioning settlements that were previously excluded from the calculation. The revised AFF 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 AFF under the current and previous methodologies:

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2019**	2018	**2019**	2018
Cash flow from operating activities	**3,299**	6,508	**(1,770)**	13,910
Changes in non-cash working capital	**2,707**	(1,754)	**14,547**	(1,611)
Other	**108**	(4)	**80**	33
Transaction, restructuring and other costs	**82**	783	**908**	1,048
Adjusted funds flow under current methodology	**6,196**	5,533	**13,765**	13,380
Decommissioning settlements	**374**	579	**3,675**	1,406
AFF under previous methodology	**6,570**	6,112	**17,440**	14,786

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 (loss) 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 earnings (loss) before income tax:

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2019**	2018	**2019**	2018
Net loss before income tax	**(2,514)**	(2,722)	**(20,658)**	(29,697)
Add (deduct):				
Interest	**3,639**	1,851	**10,698**	5,214
Depletion and depreciation	**10,224**	8,903	**30,004**	24,578
Depreciation on right-of-use assets	**686**	—	**2,058**	—
Exploration and evaluation expense	**223**	46	**536**	292
Unrealized loss (gain) on derivatives	**(5,194)**	1,884	**3,999**	16,399
Impairment loss (gain)	**—**	—	**—**	(162)
Accretion	**817**	558	**2,546**	1,689
Loss (gain) on foreign exchange	**990**	(1,084)	**(2,210)**	1,932
Change in other liabilities	**—**	—	**(3,283)**	—
Share – based compensation	**157**	190	**500**	553
Gain on sale of properties	**(12)**	(2,905)	**(100)**	(2,952)
Gain on warrant liability	**(60)**	(70)	**(666)**	(209)
Transaction costs, reorganization and other costs[1]	**82**	783	**908**	1,048
Pro-forma impact of acquisitions	**—**	—	**—**	131
Bank Adjusted EBITDAX	**9,038**	7,434	**24,332**	18,816

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.

Net Debt

Net debt is a non-IFRS measure, defined as long-term debt plus working capital surplus or deficit. Net debt is a measure commonly used in the oil and gas industry for assessing the liquidity of a company.

The following table provides a calculation of net debt:

($000s)	**September 30, 2019**	December 31, 2018
Working capital (deficit)[1]	**2,682**	(16,139)
Long-term debt	**(114,811)**	(101,144)
Total net debt	**(112,130)**	(117,283)

[1] Working capital (deficit) is a non-IFRS measure and is defined above under "Other Advisories".