PRAIRIESKY
ROYALTY LTD

TSX: PSK

MANAGEMENT'S DISCUSSION AND ANALYSIS / FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2018

HIGH MARGINS ZERO CAPITAL

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for PrairieSky Royalty Ltd. ("PrairieSky" or the "Company") should be read in conjunction with the unaudited interim condensed consolidated financial statements for the three and nine months ended September 30, 2018 and 2017 ("interim condensed consolidated financial statements") and the audited consolidated financial statements and related notes as at and for the years ended December 31, 2017 and 2016. This MD&A has been prepared as of October 29, 2018.

The unaudited interim condensed consolidated financial statements and comparative information have been prepared in Canadian dollars and in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). PrairieSky receives royalty income on production; as such, the production volumes are equivalent on a gross and net basis.

Certain measures in this document do not have any standardized meaning as prescribed by IFRS and, therefore, are considered non-GAAP measures. Non-GAAP measures are commonly used in the oil and gas industry and by PrairieSky to provide potential investors with additional information regarding the Company's liquidity and its ability to generate funds to conduct its business. Non-GAAP measures include Operating Netback, Operating Netback per BOE and Funds from Operations per Share, basic and diluted. Further information can be found in the Non-GAAP Measures section of this MD&A.

The following volumetric measures may be abbreviated throughout this MD&A: barrel ("bbl") per day ("bbls/d"), barrel of oil equivalent ("BOE") per day ("BOE/d"), thousand cubic feet ("Mcf"), and million cubic feet ("MMcf") per day ("MMcf/d"). BOE is an industry measurement to summarize the amount of energy equivalent found in a barrel of crude oil. See the discussion on energy conversions in the Advisory section of this MD&A for further explanation.

Readers should also read the Advisory section located at the end of this MD&A, which provides information on Forward-Looking Statements, oil, natural gas and natural gas liquids ("NGL") conversions, currency and references to PrairieSky.

FINANCIAL AND OPERATIONAL RESULTS

(millions, except per share or as otherwise noted)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
FINANCIAL				
Revenues	**$ 78.1**	$ 71.7	**$ 222.2**	$ 254.2
Funds from Operations	**67.0**	66.8	**181.2**	209.1
Per Share - basic(1)(4)	**0.29**	0.28	**0.77**	0.88
Per Share - diluted(1)(4)	**0.28**	0.28	**0.77**	0.88
Net Earnings and Comprehensive Income	**28.5**	19.4	**73.4**	80.7
Per Share - basic and diluted(1)	**0.12**	0.08	**0.31**	0.34
Dividends declared(2)	**45.8**	44.3	**136.4**	132.0
Per Share	**0.1950**	0.1875	**0.5800**	0.5575
Acquisitions, including non-cash consideration	**19.5**	20.3	**44.9**	299.7
Working Capital at period end	**10.6**	98.7	**10.6**	98.7
Shares outstanding				
Shares outstanding at period end	**234.7**	236.3	**234.7**	236.3
Weighted average - basic	**235.0**	236.4	**235.4**	236.6
Weighted average - diluted	**235.3**	236.7	**235.7**	236.9
OPERATIONAL				
Royalty Production Volumes				
Crude Oil (bbls/d)	**9,018**	9,033	**8,950**	9,614
NGL (bbls/d)	**2,503**	2,600	**2,391**	2,753
Natural Gas (MMcf/d)	**71.5**	75.3	**71.8**	79.1
Royalty Production (BOE/d)(3)	**23,438**	24,183	**23,308**	25,550
Realized Pricing				
Crude Oil ($/bbl)	**66.68**	47.61	**64.12**	51.22
NGL ($/bbl)	**37.32**	25.02	**39.17**	28.30
Natural Gas ($/Mcf)	**1.15**	1.25	**1.19**	1.90
Total ($/BOE)(3)	**33.11**	24.36	**32.31**	28.20
Operating Netback per BOE(4)	**$ 30.47**	$ 19.77	**$ 29.23**	$ 24.17
Funds from Operations per BOE	**$ 31.07**	$ 30.02	**$ 28.48**	$ 29.98
Oil Price Benchmarks				
West Texas Intermediate (WTI) (US$/bbl)	**68.81**	48.15	**66.29**	50.07
Edmonton Light Sweet ($/bbl)	**77.15**	57.46	**75.57**	62.19
Western Canadian Select (WCS) crude oil differential to WTI (US$/bbl)	**(22.20)**	(9.94)	**(21.92)**	(11.87)
Natural Gas Price Benchmark				
AECO monthly index ($/Mcf)	**1.35**	2.05	**1.41**	2.59
AECO daily index ($/Mcf)	**1.19**	1.61	**1.48**	2.37
Foreign Exchange Rate (US$/CAD$)	**0.7683**	0.7950	**0.7768**	0.7649

(1) Net Earnings and Comprehensive Income and Funds from Operations per Share are calculated using the weighted average number of common shares outstanding.
(2) A dividend of $0.065 per common share was declared on September 10, 2018. The dividend was paid on October 15, 2018 to shareholders of record as at September 28, 2018.
(3) See “Conversions of Natural Gas to BOE”.
(4) Funds from Operations per Share and Operating Netback per BOE are defined under the Non-GAAP Measures section in this MD&A.

RESULTS OVERVIEW

HIGHLIGHTS

During the three-month period ended September 30, 2018 (“Q3 2018”), PrairieSky reported:

- Revenues totaled $78.1 million, consisting of $71.4 million of royalty production revenue, $1.2 million of lease rental income, $5.3 million of bonus consideration and $0.2 million of other income.
- Funds from operations totaled $67.0 million ($0.29 per share basic and $0.28 per share diluted).
- Royalty production averaged 23,438 BOE per day consisting of average crude oil production volumes of 9,018 bbls per day, average NGL production volumes of 2,503 bbls per day and average natural gas production volumes of 71.5 MMcf per day.
- Completed acquisitions of gross overriding royalties on producing properties and emerging plays, as well as seismic in the period for cash consideration of $19.5 million.
- Positive working capital of $10.6 million at September 30, 2018.
- Dividends declared of $45.8 million ($0.1950 per share).
- Purchased for cancellation 514,200 common shares at a weighted average price of $24.19 per common share for total consideration of $12.5 million under the normal course issuer bid (“NCIB”).

During the nine-month period ended September 30, 2018 (“YTD 2018”), PrairieSky reported:

- Revenues totaled $222.2 million, consisting of $205.6 million of royalty production revenue, $5.6 million of lease rental income, $10.1 million of bonus consideration and $0.9 million of other income.
- Funds from operations totaled $181.2 million ($0.77 per share basic and diluted).
- Royalty production averaged 23,308 BOE per day consisting of average crude oil production volumes of 8,950 bbls per day, average NGL production volumes of 2,391 bbls per day and average natural gas production volumes of 71.8 MMcf per day.
- Completed acquisitions of gross overriding royalties on producing properties and emerging plays, as well as seismic in the period for cash consideration of $44.9 million.
- Dividends declared of $136.4 million ($0.5800 per share).
- Purchased for cancellation 1,311,300 common shares at a weighted average price of $27.36 per common share for total consideration of $35.9 million under the NCIB.
- Entered into a three-year, extendible $200 million revolving and $25 million operating credit facility agreement with a syndicate of lenders.

BUSINESS OVERVIEW

PRAIRIESKY ROYALTY

PrairieSky's asset base includes a geologically and geographically diverse portfolio of Fee Lands (as defined herein) that encompasses approximately 7.8 million acres with petroleum and/or natural gas rights, an additional 1.1 million acres in coal only titles, and approximately 7.8 million acres of GORR Lands (as defined herein) and other acreage (collectively, the "Royalty Properties").

The Royalty Properties are comprised of: (i) fee simple mineral title in lands prospective for petroleum, natural gas, NGL and certain other minerals located predominantly in central and southern Alberta and western Saskatchewan (the "Fee Lands"); (ii) lessor interests in and to leases that are currently issued in respect of certain Fee Lands ("Lessor Interests"); and (iii) overriding royalty interests ("GORR Interests") on lands ("GORR Lands") across Western Canada.

PrairieSky is focused on encouraging third parties to actively develop the Royalty Properties and growing our royalty ownership by strategically seeking additional petroleum and natural gas royalty assets that provide PrairieSky with medium-term to long-term value enhancement potential. The Company does not directly conduct operations to explore for, develop or produce petroleum or natural gas; rather, third-party development of the Royalty Properties provides the Company with royalty production revenues as petroleum and natural gas are produced from such properties. PrairieSky carries on business in the provinces of Alberta, Saskatchewan, British Columbia and Manitoba.

PrairieSky's operations include royalty income earned through crude oil, NGL and natural gas produced on the Royalty Properties. The Company's royalty revenues are derived from: (i) the Lessor Interests that are leased out by the Company and upon which lessees pay lessor royalties, and (ii) GORR Interests on GORR Lands leased by third parties.

PrairieSky receives royalty production revenue from over 38,000 wells and receives payments from approximately 350 different industry payors. The Company receives approximately 75% of its monthly revenue from 31 payors. Royalties are calculated on a fixed percentage or sliding scale formula. The average royalty rate for Q3 2018 was approximately 6.0%. Some royalty agreements allow for the deduction of certain costs.

Petroleum and natural gas royalty structures are typically linked directly to production volumes from the lands, with certain royalty structures linked to production volumes and price. As a result, the Company's net earnings can be significantly impacted by fluctuations in commodity prices and production volumes. Production volumes can be influenced by various factors, including the extent of exploration and development activity by third parties on the Royalty Properties, the timing and amount of capital expenditures, and the expertise and financial resources of third-party lessees. Commodity pricing is influenced by market supply and demand as well as other factors such as weather, quality of product, access to markets, foreign currency fluctuations, and geopolitical risk. The Company is able to mitigate some of these risks to the extent that there are a multitude of third parties actively exploring and developing the Royalty Properties and the production of natural gas, crude oil, and NGL is diversified.

As a royalty owner, PrairieSky does not bear the operational risks typically associated with the upstream oil and natural gas exploration and production business. The Company does not bear the operational or financial risks of drilling, completing or operating wells and related infrastructure. The Company is not responsible for site restoration and abandonment costs. Capital, operational and abandonment costs are the responsibility of the third parties conducting operations on the Royalty Properties. Substantially all the capital expenditures made by PrairieSky are discretionary.

Costs incurred by the Company are primarily production and mineral taxes, administrative expenses and corporate income taxes. Administrative expenses include lease administration costs such as land title management, contract administration, technical evaluation, negotiations and compliance costs to secure mineral rights and ensure accurate royalty revenue receipts.

Management's discussion and analysis for this reporting period focuses on the three and nine months ended September 30, 2018.

PRAIRIESKY'S 2018 OUTLOOK

Management does not provide guidance. As such, this discussion relates only to general economic conditions experienced by the Company as of the date of this MD&A. The near-term economic environment in which PrairieSky operates remains challenged with continued low natural gas prices, higher discounts for Canadian light and heavy crude oil, and constrained takeaway capacity for both crude oil and natural gas. There continues to be limited access to capital for many industry participants, which is further impacted by changes to legislative and regulatory frameworks in the jurisdictions in which the Company and royalty payors carry on business, including but not limited to, tariffs, environmental assessments, and limits related to carbon emissions, and less competitive corporate tax rates than other jurisdictions. Management continues to deploy its risk mitigating strategies including proactive monitoring of economic conditions, a constant and proactive compliance and collections program, paying close attention to controllable costs and a disciplined approach to acquisitions. PrairieSky maintains a strong balance sheet and continues to employ a conservative capital structure. As at September 30, 2018, PrairieSky had positive working capital of $10.6 million.

Management continues to monitor current commodity prices, currency exchange rates, industry activity levels and third-party guidance for anticipated capital expenditures during 2018 and beyond. Given PrairieSky has no operational control over capital expenditures on its lands, it is difficult to predict activity levels and the timing thereof with a high degree of certainty.

PrairieSky's diversity in crude oil and natural gas plays and payors, along with an active royalty compliance program, assists in reducing collection and credit risk. The Company takes certain royalty volumes in-kind which, in conjunction with the above processes, further assists in managing collection and credit risk.

PRAIRIESKY'S STRATEGY

The Company's objective is to generate significant cash flow and growth for shareholders through indirect oil and gas investment at relatively low risk and low cost to the Company. The Company seeks to achieve this objective by: (i) focusing on leasing activity and organic growth of royalty production revenue from the Royalty Properties; (ii) proactively monitoring and managing the portfolio of Royalty Properties to ensure third party adherence to lease terms and contractual provisions (including offset well obligations); (iii) managing controllable costs; and (iv) selectively pursuing strategic business development opportunities that are relatively low risk to the Company and accretive to shareholders. The Company intends to distribute the majority of cash flow in the form of dividends and share repurchases and cancellations over time.

ROYALTY PRODUCTION

ROYALTY PRODUCTION VOLUMES

	Three months ended September 30		Nine months ended September 30	
(Average daily)	2018	2017	2018	2017
Crude Oil (bbls/d)	**9,018**	9,033	**8,950**	9,614
NGL (bbls/d)	**2,503**	2,600	**2,391**	2,753
Natural Gas (MMcf/d)	**71.5**	75.3	**71.8**	79.1
Total Royalty Production (BOE/d)	**23,438**	24,183	**23,308**	25,550

PrairieSky's average daily royalty production volumes for Q3 2018 were 38% oil, 11% NGL and 51% natural gas as compared to the three-month period ended September 30, 2017 ("Q3 2017") when the production volume split was 37% oil, 11% NGL and 52% natural gas. The average daily royalty production volume split for YTD 2018 was 38% oil, 10% NGL and 52% natural gas which is consistent with the nine-month period ended September 30, 2017 ("YTD 2017"). There is a natural delay between the timing of production and when PrairieSky receives its royalty interest production and revenue from operators. Due to this delay, positive and negative adjustments related to prior periods may be included in PrairieSky's royalty production volumes and/or revenue. In addition, collections related to compliance recoveries result in adjustments to royalty production volumes and royalty revenue related to prior periods.

PrairieSky's crude oil, NGL and natural gas production volumes are primarily marketed with lessees' production. The Company actively reviews its counterparties and takes certain royalty volumes in-kind to mitigate credit risk, as appropriate. PrairieSky is exposed to commodity price volatility. The Company has no commodity price hedges in place and does not currently intend to enter into any commodity price hedges.

PrairieSky's compliance department continually reviews leasing agreements and royalty calculations. Compliance adjustments are not recorded in the financial statements until collection is certain.

For the three months ended September 30, 2018

Crude oil production volumes for Q3 2018 of 9,018 bbls per day were flat with the 9,033 bbls per day reported in Q3 2017 as royalty production volumes from new drilling on the Royalty Properties and acquisitions, along with effect of a recovering price on sliding scale royalties, offset natural declines. Crude oil production volumes in Q3 2018 were negatively impacted as a result of declines on a Nisku oil pool and a Bakken oil pool, both in Alberta. Both Q3 2017 and Q3 2018 were impacted by positive volume adjustments from prior periods.

NGL production volumes for Q3 2018 of 2,503 bbls per day have decreased 4% from 2,600 bbls per day reported in Q3 2017 as royalty production volumes from new drilling on the Royalty Properties were outweighed by natural declines. Challenging natural gas pricing has resulted in a slow-down in both drilling and workover activity across Western Canada which has impacted NGL royalty production. Both Q3 2017 and Q3 2018 were impacted by positive volume adjustments from prior periods.

Natural gas production volumes for Q3 2018 of 71.5 MMcf per day were 5% lower than the 75.3 MMcf per day reported in Q3 2017 as royalty production volumes from new drilling on the Royalty Properties were outweighed by natural declines. Challenging natural gas pricing has resulted in a slow-down in both drilling and workover activity across Western Canada which has impacted natural gas royalty production. Both Q3 2017 and Q3 2018 were impacted by positive volume adjustments from prior periods; however, Q3 2017 natural gas volumes included additional compliance recoveries that were not repeated in Q3 2018.

For the nine months ended September 30, 2018

Crude oil production volumes for YTD 2018 of 8,950 bbls per day were 7% lower than the 9,614 bbls per day reported in YTD 2017 as royalty production volumes from new drilling on the Royalty Properties and acquisitions, along with the effect of a recovering price on sliding scale royalties, were outweighed by natural declines. The decrease in production was primarily a result of declines on a Nisku oil pool and a Bakken oil pool, both in Alberta. YTD 2018, production on these two pools has remained relatively flat.

NGL production volumes for YTD 2018 of 2,391 bbls per day have decreased 13% from 2,753 bbls per day reported in YTD 2017 as royalty production volumes from new drilling on the Royalty Properties were outweighed by natural declines. YTD 2018, there was a reduction in ethane volumes due to curtailments resulting in lower corporate NGL yields as compared to YTD 2017. Challenging natural gas pricing has resulted in a slow-down in both drilling and workover activity across Western Canada which has impacted NGL royalty production. Both YTD 2017 and YTD 2018 periods were impacted by positive volume adjustments from prior periods; however, YTD 2017 NGL volumes included additional compliance recoveries that were not repeated in YTD 2018.

Natural gas production volumes for YTD 2018 of 71.8 MMcf per day were 9% lower than the 79.1 MMcf per day reported in YTD 2017 as royalty production volumes from new drilling on the Royalty Properties were outweighed by natural declines. Challenging natural gas pricing has resulted in a slow-down in both drilling and workover activity across Western Canada which has impacted natural gas royalty production. Both YTD 2017 and YTD 2018 periods were impacted by positive volume adjustments from prior periods; however, YTD 2017 natural gas volumes included additional compliance recoveries that were not repeated in YTD 2018.

FINANCIAL RESULTS

OPERATING RESULTS

	Three months ended September 30, 2018		**Three months ended September 30, 2017**	
	($ millions)	**($/BOE)[2]**	**($ millions)**	**($/BOE)[2]**
Royalty Production Revenue	**$ 71.4**	**$ 33.11**	$ 54.2	$ 24.36
Administrative Expenses	**(4.6)**	**(2.13)**	(8.4)	(3.78)
Production and Mineral Taxes	**(1.1)**	**(0.51)**	(1.8)	(0.81)
Operating Netback[1]	**$ 65.7**	**$ 30.47**	$ 44.0	$ 19.77

	Nine months ended September 30, 2018		**Nine months ended September 30, 2017**	
	($ millions)	**($/BOE)[2]**	**($ millions)**	**($/BOE)[2]**
Royalty Production Revenue	**$ 205.6**	**$ 32.31**	$ 196.7	$ 28.20
Administrative Expenses	**(15.8)**	**(2.48)**	(23.6)	(3.38)
Production and Mineral Taxes	**(3.8)**	**(0.60)**	(4.5)	(0.65)
Operating Netback[1]	**$ 186.0**	**$ 29.23**	$ 168.6	$ 24.17

(1) Non-GAAP measure. See "Non-GAAP Measures" in this MD&A.
(2) See "Conversions of Natural Gas to BOE".

REVENUES

Royalty Revenue by Product (millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Crude Oil	**$ 55.4**	$ 39.5	**$ 156.7**	$ 134.4
NGL	**8.6**	6.0	**25.6**	21.3
Natural Gas	**7.4**	8.7	**23.3**	41.0
	71.4	54.2	**205.6**	196.7
Other Revenue				
Lease Rental Income	**$ 1.2**	$ 1.6	**$ 5.6**	$ 7.7
Bonus Consideration	**5.3**	15.5	**10.1**	48.0
Other Income	**0.2**	0.4	**0.9**	1.8
	6.7	17.5	**16.6**	57.5
Total Revenue	**$ 78.1**	$ 71.7	**$ 222.2**	$ 254.2

Revenues by Classification (millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Fee Lands	**$ 50.4**	$ 41.1	**$ 148.8**	$ 148.1
GORR Interests	**21.0**	13.1	**56.8**	48.6
Royalty Revenue	**71.4**	54.2	**205.6**	196.7
Other Revenue	**6.7**	17.5	**16.6**	57.5
Total Revenue	**$ 78.1**	$ 71.7	**$ 222.2**	$ 254.2

Pricing	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Benchmark				
WTI (US$/bbl)	**68.81**	48.15	**66.29**	50.07
Edmonton Light Sweet ($/bbl)	**77.15**	57.46	**75.57**	62.19
WCS differential to WTI (US$/bbl)	**(22.20)**	(9.94)	**(21.92)**	(11.87)
AECO monthly index ($/mcf)	**1.35**	2.05	**1.41**	2.59
AECO daily index ($/mcf)	**1.19**	1.61	**1.48**	2.37
Foreign Exchange Rate (US$/CAD$)	**0.7683**	0.7950	**0.7768**	0.7649
Realized				
Crude Oil ($/bbl)	**66.68**	47.61	**64.12**	51.22
NGL ($/bbl)	**37.32**	25.02	**39.17**	28.30
Natural Gas ($/Mcf)	**1.15**	1.25	**1.19**	1.90
Total ($/BOE)	**33.11**	24.36	**32.31**	28.20

The Company's average royalty rate for Q3 2018 and Q3 2017 was approximately 6.0% and 6.1%, respectively. The average royalty rate has declined due to an increased weighting of GORR production volumes which are generally at lower royalty rates. During Q3 2018, royalty revenue was $71.4 million compared to $54.2 million for the same period in 2017, an increase of 32% compared to Q3 2017 as a result of higher average realized pricing offsetting lower total production volumes.

During Q3 2018, revenue from Lessor Interests was $50.4 million or 71% of total royalty production revenue. Revenue from GORR Interests was $21.0 million or 29% of total royalty production revenue for the same time period. In the comparative period, $41.1 million or 76% and $13.1 million or 24%, respectively, of royalty production revenue was generated from Lessor Interests and GORR Interests. The increase in revenue generated from GORR Interests as a percentage of total royalty production revenue is reflective of the impact of revenues from GORR acquisitions and land fund arrangements completed in 2016 and 2017 and increased near-term activity on GORR lands. In addition to royalty revenue from Lessor Interests, all lease rental income and bonus consideration is generated from Fee Lands.

The Company's average royalty rate for YTD 2018 and YTD 2017 was approximately 6.0% and 6.1%, respectively. The average royalty rate has declined due to an increased weighting of GORR production volumes which are generally at lower royalty rates. During YTD 2018, royalty revenue was $205.6 million compared to $196.7 million for the same period in 2017. YTD 2018 royalty production revenue increased by 5% compared to YTD 2017 as a result of higher average realized pricing being offset by lower production volumes.

During YTD 2018, revenue from the Lessor Interests was $148.8 million or 72% of total royalty production revenue. Revenue from GORR Interests was $56.8 million or 28% of total royalty production revenue for the same period. In the comparative period, $148.1 million or 75% and $48.6 million or 25%, respectively, of royalty revenue was generated from Lessor Interests and GORR Interests. The increase in revenue generated from GORR Interests as a percentage of total royalty revenue is reflective of the impact of revenues from GORR acquisitions completed in 2017 and increased near-term activity on GORR lands.

During Q3 2018, the Company averaged realized crude oil pricing of $66.68 per bbl, NGL pricing of $37.32 per bbl and natural gas pricing of $1.15 per Mcf. Liquids pricing increased from Q3 2017 when the Company averaged realized crude oil pricing of $47.61 per bbl and NGL pricing of $25.02 per bbl due to increased benchmark pricing offset by wider light and heavy oil differentials. Realized natural gas pricing declined to $1.15 per Mcf in Q3 2018 from $1.25 per Mcf in Q3 2017 due to decreases in benchmark pricing. YTD 2018, the Company averaged realized crude oil pricing of $64.12 per bbl, NGL pricing of $39.17 per bbl and natural gas pricing of $1.19 per Mcf. Liquids pricing increased with 2018 benchmark pricing from YTD 2017 when the Company averaged realized crude oil pricing of $51.22 per bbl and NGL pricing of $28.30 per bbl. Realized natural gas pricing decreased to $1.19 per Mcf YTD 2018 from $1.90 per Mcf in the prior year due to decreases in benchmark pricing.

Royalty compliance recoveries are the cash payments received as a result of the extensive process of identifying, analyzing, resolving and collecting corrected payments from royalty payors. Cash received from compliance recoveries can cover a number of periods. PrairieSky's compliance department continually reviews leasing agreements and royalty calculations. Compliance adjustments are not recorded in the financial statements until collection is certain. For Q3 2018 and YTD 2018, the Company collected $2.1 million (Q3 2017 - $2.2 million) and $7.7 million (YTD 2017 - $5.5 million), respectively, in compliance recoveries. Compliance recoveries are included in royalty production revenue for the period.

Other revenue consisted primarily of lease rental income from leases that are currently issued in respect of certain Fee Lands and lease bonus consideration. Bonus consideration revenue for Q3 2018 and YTD 2018 was $5.3 million (Q3 2017 - $15.5 million) and $10.1 million (YTD 2017 - $48.0 million), respectively. Both the amount and timing of bonus consideration revenue can vary significantly from quarter to quarter as it relates to the unique circumstances of each transaction.

ADMINISTRATIVE EXPENSES

(millions)	Three months ended September 30 2018	Three months ended September 30 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
Salaries and Benefits	**$ 3.3**	$ 3.3	**$ 10.3**	$ 10.4
Share-Based Compensation	**(0.6)**	3.3	**(1.1)**	8.1
Office Expense	**1.0**	1.0	**3.4**	2.5
Public Company Expense	**0.2**	0.2	**1.2**	1.2
Information Technology and Other	**0.7**	0.6	**2.0**	1.4
Total Administrative Expenses	**$ 4.6**	$ 8.4	**$ 15.8**	$ 23.6

	Three months ended September 30, 2018 ($ millions)	Three months ended September 30, 2018 ($/BOE)[1]	Three months ended September 30, 2017 ($ millions)	Three months ended September 30, 2017 ($/BOE)[1]
Administrative – cash	**$ 5.2**	**$ 2.41**	$ 5.1	$ 2.29
Administrative – non-cash	**(0.6)**	**(0.28)**	3.3	1.49
Total Administrative Expenses	**$ 4.6**	**$ 2.13**	$ 8.4	$ 3.78

	Nine months ended September 30, 2018		Nine months ended September 30, 2017	
	($ millions)	($/BOE)[1]	($ millions)	($/BOE)[1]
Administrative – cash	**$ 22.0**	**$ 3.45**	$ 21.9	$ 3.14
Administrative – non-cash	**(6.2)**	**(0.97)**	1.7	0.24
Total Administrative Expenses	**$ 15.8**	**$ 2.48**	$ 23.6	$ 3.38

(1) See "Conversions of Natural Gas to BOE".

PrairieSky is committed to cost control in its business. Administrative expenses for Q3 2018 and YTD 2018 were $2.13 per BOE (Q3 2017 - $3.78 per BOE) and $2.48 per BOE (YTD 2017 - $3.38 per BOE), respectively. Administrative expenses include both cash and non-cash charges which relate to share-based compensation plans. Non-cash administrative expenses related to share-based compensation are impacted by the closing share price at period end and as such, are subject to variability.

The Company payouts related to share-based compensation during Q3 2018 were $nil (Q3 2017 - $nil million) and $5.1 million during YTD 2018 (YTD 2017 - $6.4 million). When cash share-based payments are made, there is an increase in cash administrative expenses in the period, with a corresponding decrease in non-cash administrative expenses. There were no cash payments in Q3 2018 due to the vesting timeframe of the RSU and PSU plans in the current year, with units vesting in Q1 2018.

Of the total share-based compensation expense for Q3 2018, $0.4 million (Q3 2017 - $0.6 million) related to the stock option plan and there was a $0.6 million recovery (Q3 2017 - $2.4 million expense) related to the restricted share unit ("RSU") and performance share unit ("PSU") plans. The Company recorded a $0.4 million recovery (Q3 2017 - $0.3 million expense) related to the Company's Deferred Share Unit ("DSU") plan in Q3 2018.

Of the total share-based compensation expense for YTD 2018, $1.4 million (YTD 2017 - $1.5 million) related to the stock option plan and there was a $2.2 million recovery (YTD 2017 - $5.8 million expense) related to the RSU and PSU plans. The Company recorded a $0.3 million recovery (YTD 2017 - $0.8 million expense) related to the Company's DSU plan YTD 2018.

Total outstanding units and options from all employee incentive plans is 0.6% of total common shares outstanding at September 30, 2018, consistent with prior years.

PRODUCTION AND MINERAL TAXES

	Three months ended September 30		Nine months ended September 30	
(millions, except per BOE amounts)	**2018**	**2017**	**2018**	**2017**
Production and mineral taxes	**$ 1.1**	$ 1.8	**$ 3.8**	$ 4.5
$/BOE[1]	**$ 0.51**	$ 0.81	**$ 0.60**	$ 0.65

(1) See "Conversions of Natural Gas to BOE".

Production and mineral taxes are levied on an annual basis on the value of crude oil and natural gas production or amount of acreage from non-Crown lands. For Q3 2018, production and mineral taxes, which includes Alberta freehold mineral tax and Saskatchewan acreage tax, averaged 1.5% of royalty revenues compared to 3.3% in the comparable 2017 period. YTD 2018, production and mineral taxes averaged 1.8% compared to 2.3% for the YTD 2017 period. Saskatchewan acreage tax does not vary with pricing while Alberta freehold mineral taxes are impacted by both production and pricing. Production and mineral taxes are based on an annual estimate which can result in variances from quarter to quarter.

DEPLETION, DEPRECIATION AND AMORTIZATION ("DD&A")

	Three months ended September 30		Nine months ended September 30	
(millions, except per BOE amounts)	2018	2017	2018	2017
Depletion, Depreciation and Amortization	**$ 35.4**	$ 40.8	**$ 105.2**	$ 129.3
$/BOE(1)	**$ 16.42**	$ 18.34	**$ 16.53**	$ 18.54

(1) See "Conversions of Natural Gas to BOE".

The Company depletes its royalty assets using the unit-of-production method based on the total proved and probable reserves of its Royalty Properties. Corporate assets are depreciated on a straight-line basis. DD&A per BOE is lower in Q3 2018 and YTD 2018 than the prior year comparative periods due to a lower depletable base and increased reserves. DD&A per BOE will fluctuate depending on the royalty assets acquired, if any, the amount of reserves added, and production volumes in the period.

EXPLORATION AND EVALUATION EXPENSE ("E&E")

	Three months ended September 30		Nine months ended September 30	
(millions, except per BOE amounts)	2018	2017	2018	2017
Exploration and Evaluation Expense	**$ 0.2**	$ 0.7	**$ 0.9**	$ 4.7
$/BOE(1)	**$ 0.09**	$ 0.31	**$ 0.14**	$ 0.67

(1) See "Conversions of Natural Gas to BOE".

During Q3 2018 and YTD 2018, $0.2 million (Q3 2017 - $0.7 million) and $0.9 million (YTD 2017 - $4.7 million), respectively, of costs associated with expired Crown mineral leases and gross overriding royalties were recognized as an expense. The expense will vary period to period as a result of the timing of lease expiries, if any.

FINANCE

	Three months ended September 30		Nine months ended September 30	
($ millions)	2018	2017	2018	2017
Finance Income	**$ (0.1)**	$ (0.4)	**$ (0.3)**	$ (0.9)
Finance Expense	**0.3**	-	**0.5**	0.1
Net Finance Items	**$ 0.2**	$ (0.4)	**$ 0.2**	$ (0.8)

Finance income includes interest on funds on deposit, short term investments and the royalty note receivable. Finance income decreased 75% from Q3 2017 to Q3 2018 and 67% from YTD 2017 to YTD 2018 as a result of the decrease in the cash balance due to acquisitions completed for cash consideration during YTD 2018 and throughout 2017. Finance expense has increased from Q3 2017 and YTD 2017 as a result of the renewal and extension of the credit facility as outlined below in the "Financing Activities" section of this MD&A.

INCOME TAX

	Three months ended September 30		Nine months ended September 30	
(millions)	2018	2017	2018	2017
Current Tax Expense (Recovery)	**$ 5.6**	$ (0.7)	**$ 17.9**	$ 7.2
Deferred Tax Expense	**2.5**	1.7	**5.0**	5.0
Income Tax Expense	**8.1**	$ 1.0	**22.9**	$ 12.2

The Company's interim income tax expense is determined using the estimated annual effective income tax rate applied to year-to-date net earnings before tax. The Company's effective tax rate differs from the

Canadian statutory tax rate of 27% primarily as a result of the reversal of the initial difference between the carrying value of net assets transferred and the tax pools acquired on May 27, 2014, for which no deferred tax asset was recognized, partially offset by non-deductible employee-related expenses.

NET EARNINGS

Net earnings for Q3 2018 and YTD 2018 were $28.5 million ($0.12 per share, basic and diluted) and $73.4 million ($0.31 per share, basic and diluted), respectively, compared to $19.4 million for Q3 2017 ($0.08 per share, basic and diluted) and $80.7 million for YTD 2017 ($0.34 per share, basic and diluted). Net earnings for Q3 2018 was higher than Q3 2017 as increased revenues and the benefit of lower administrative and depletion expense more than offset the increase to income tax. Net earnings for YTD 2018 was lower than YTD 2017 as the benefits of lower DD&A and administrative expenses were more than offset by lower total revenues and higher income taxes.

ACQUISITIONS

During Q3 2018, the Company completed acquisitions totaling $19.5 million (Q3 2017 - $20.3 million) comprised of royalty assets of $7.7 million (Q3 2017 - $2.6 million) and E&E assets, consisting of royalty interests, seismic and undeveloped land, of $11.8 million (Q3 2017 - $17.7 million).

YTD 2018, the Company completed acquisitions totaling $44.9 million (YTD 2017 - $299.7 million) comprised of royalty assets of $13.5 million (YTD 2017 - $38.5 million) and E&E assets, consisting of royalty interests, seismic and undeveloped land, of $31.4 million (YTD 2017 - $261.2 million).

YTD 2017 acquisitions included the acquisition of a 4% gross overriding royalty on current and future phases of the Lindbergh SAGD thermal oil project, as well as seismic over certain lands in British Columbia and Alberta for total cash consideration of $250 million (the “Lindbergh Acquisition”).

LIQUIDITY AND CAPITAL RESOURCES

	Three months ended September 30		Nine months ended September 30	
(millions)	**2018**	**2017**	**2018**	**2017**
Net Cash From (Used In)				
Operating Activities	**$ 67.3**	$ 79.3	**$ 171.4**	$ 221.4
Investing Activities	**(19.5)**	(20.3)	**(44.9)**	(268.1)
Financing Activities	**(57.8)**	(53.9)	**(171.6)**	114.7
Increase (Decrease) in Cash and Cash Equivalents	**(10.0)**	5.1	**(45.1)**	68.0
Cash and Cash Equivalents, Beginning of Period	**$ 10.0**	96.9	**$ 45.1**	34.0
Cash and Cash Equivalents, End of Year	**$ -**	$ 102.0	**$ -**	$ 102.0

OPERATING ACTIVITIES

Net cash from operating activities for Q3 2018 was $67.3 million compared to $79.3 million for the comparable period in 2017 as a result of a positive $12.5 million change in non-cash working capital in the Q3 2017 period, due to the timing of the collection of receivables.

Net cash from operating activities for YTD 2018 was $171.4 million compared to $221.4 million for the comparable period in 2017 as a result of lower net income, as previously discussed, as well as the timing of the settlement of non-cash working capital items. There was a $12.3 million inflow from non-cash working capital items during YTD 2017; whereas, during YTD 2018 there was a decrease in non-cash working capital of $9.8 million.

Funds from operations is utilized by management to evaluate the ability of the Company to generate cash from operations. This is considered a measure of operating performance as it demonstrates the Company’s ability, on an ongoing basis, to fund distributions of cash flow to shareholders as dividends, to repurchase common shares under the Company's NCIB, as well as fund complementary acquisitions. Such a measure provides a useful indicator of the Company's operations, on an ongoing basis, by eliminating certain non-cash charges. Funds from operations in Q3 2018 and YTD 2018 were $67.0 million and $181.2 million, respectively, flat with $66.8 million in Q3 2017 and a 13% decrease from $209.1 million YTD 2017. The YTD decrease is due to lower bonus consideration and higher current tax expense in the YTD 2018 period.

The Company had positive working capital of $10.6 million as at September 30, 2018. At September 30, 2018, accounts receivable and accrued revenue consisted primarily of trade receivables and accrued revenue related to lease and royalty payments, and the royalty note receivable. In the oil and gas industry, accounts receivable from industry partners are typically settled in the following month; however, payments to royalty owners are often delayed longer, and as a result, actual payments may differ from estimates recorded. Accounts payable and accrued liabilities consisted primarily of production and mineral taxes payable and share-based compensation and salary related accruals.

INVESTING ACTIVITIES

For Q3 2018 and YTD 2018, cash used in investing activities was $19.5 million (Q3 2017 - $20.3 million) and $44.9 million (YTD 2017 - $268.1 million), respectively, including royalty and E&E asset acquisitions as outlined in the "Acquisitions" section of this MD&A.

FINANCING ACTIVITIES

For Q3 2018, cash used in financing activities was $57.8 million (Q3 2017 - $53.9 million). YTD 2018, cash used in financing activities was $171.6 million (YTD 2017 - cash from financing activities of $114.7 million). The dividends paid in Q3 2018 and YTD 2018 of $45.8 million and $135.9 million, respectively, were higher than in the comparable 2017 periods due to the increased dividend announced in February 2018 to $0.065 per common share per month. In addition, the Company repurchased $12.5 million in common shares under the NCIB in Q3 2018 (Q3 2017 - $9.5 million) as described below. YTD 2018, $35.9 million in common shares have been repurchased (YTD 2017 - $31.2 million).

Since inception of the NCIB, PrairieSky has purchased for cancellation 3,673,600 common shares at an average cost of $28.32 per share for total consideration of $104.0 million. Since the initial public offering in May 2014, PrairieSky has declared $804.2 million in dividends to shareholders.

Credit Facility

On May 15, 2018, the Company entered into a $200 million extendible revolving credit facility (the "Revolving Facility"), with a permitted increase to $250 million, and renewed the $25 million extendible operating credit facility (the "Operating Facility", and together with the Revolving Facility, the "Credit Facility"), with a syndicate of Canadian chartered banks.

The Credit Facility includes borrowing options of Canadian prime rate-based advances, U.S. base rate advances, LIBOR loans, bankers' acceptances and letters of credit, and will bear interest on a variable grid based on certain financial ratios, over the prevailing applicable rate for the type of loan. The Credit Facility is unsecured and does not have a borrowing base restriction. The Revolving Facility and the Operating Facility are each for three-year terms maturing on May 15, 2021 and, subject to certain requirements, are extendible annually. The credit facility has three financial covenants, whereby the Company's ratio of adjusted consolidated senior debt to EBITDA will not exceed 3.5:1.0, adjusted consolidated total debt to EBITDA will not exceed 4.0:1.0, and the adjusted consolidated total debt to capitalization ratio will not exceed 55%. The EBITDA used in the covenant calculation is adjusted for non-cash items, interest expense and income taxes. As at September 30, 2018, the Company was compliant with all covenants provided for in the lending agreement.

As at September 30, 2018, the Company had $0.5 million in bank debt outstanding on the Operating Facility (December 31, 2017 - nil). The Revolving Facility remains undrawn. The effective interest rate for both the three and nine months ended September 30, 2018 was 4.2% (three and nine months ended September 30, 2017 - nil).

Dividends and Dividend Policy

PrairieSky currently pays a monthly dividend to shareholders at the discretion of the Board. Dividends declared were $45.8 million or $0.1950 per share for Q3 2018. On February 26, 2018, the Company announced that the Board had increased the monthly dividend from $0.0625 per common share per month or $0.75 per common share on an annualized basis, to $0.065 per common share per month or $0.78 per common share on an annualized basis, effective for the March 29, 2018 record date.

The Board of Directors reviews and determines the dividend rate annually after considering expected commodity prices, foreign exchange rates, economic conditions, production volumes, income taxes, and PrairieSky's capacity to fund operating expenses and investing opportunities. The dividend rate is established with the intent of absorbing short-term market volatility over several months. It also recognizes the intention of maintaining a strong financial position to take advantage of business development opportunities and withstanding periods of commodity price volatility.

Outstanding Share Data

As at September 30, 2018, PrairieSky had 234.7 million common shares outstanding (December 31, 2017 - 236.0 million) and 1.0 million outstanding stock options (December 31, 2017 - 0.8 million). As at October 29, 2018, there were 234.7 million common shares outstanding.

Capital Structure

The Company's objective when managing its capital structure is to maintain financial flexibility in order to distribute cash to shareholders in the form of dividends and to repurchase shares for cancellation after consideration of the Company's financial requirements for its business and future growth opportunities. As a royalty company, PrairieSky does not incur capital expenditures for oil and natural gas development, which enhances its financial flexibility.

The Company's capital structure is comprised of shareholders' equity and working capital. The Company's capital structure is managed by taking into account operating activities, dividends paid to shareholders, common share repurchases, income taxes, available Credit Facility, share issuance costs and other factors. The Company's operating results and capital structure are impacted by the level of leasing and development activity by third parties on the Royalty Properties, commodity prices and the resultant royalty revenues, as well as the costs incurred by the Company.

Stewardship of the Company's capital structure is managed through its financial and operating forecast process. The Company's forecast of future cash flows is based on estimates of production, crude oil, natural gas and NGL prices, production and mineral tax expense, administrative expenses, income taxes and other investing and financing activities. The forecast is regularly updated based on changes in commodity prices, production expectations and other factors that, in the Company's view, would impact future cash flows.

On April 30, 2018 the Company announced the approval of the renewal of its NCIB by the Toronto Stock Exchange ("TSX"). The NCIB allows the Company to purchase for cancellation up to a maximum of 1,750,000 common shares over a twelve-month period which commenced on May 4, 2018 and expires no later than May 3, 2019. The Company allocated $50.0 million to repurchase common shares under the NCIB over the twelve-month period. Purchases are made on the open market through the TSX or alternative platforms at the market price of such common shares. All common shares purchased under the NCIB are cancelled.

During Q3 2018, the Company purchased for cancellation 514,200 common shares (Q3 2017 - 333,200 common shares) at a weighted average price of $24.19 per common share (Q3 2017 - $28.58 per common share) including commissions for total consideration of $12.5 million (Q3 2017 - $9.5 million). The total cost paid, including commissions and fees, was first charged to share capital to the extent of the average carrying value of the common shares purchased and the excess of $5.2 million (Q3 2017 - $4.8 million) was charged to the deficit.

YTD 2018, the Company has purchased for cancellation 1,311,300 common shares (YTD 2017 - 1,065,600 common shares) at a weighted average price of $27.36 per common share (YTD 2017 - $29.27 per common share) including commissions for total consideration of $35.9 million (YTD 2017 - $31.2 million). The total cost paid, including commissions and fees, was first charged to share capital to the extent of the average carrying value of the common shares purchased and the excess of $17.4 million (YTD 2017 - $16.2 million) was charged to the deficit. Since the inception of the NCIB, the Company has purchased for cancellation 3,673,600 common shares at an average price of $28.32 per share for total consideration of $104.0 million.

RISK MANAGEMENT

FINANCIAL RISKS

The Company is exposed to financial risks arising from its financial assets and liabilities. Financial risks include market risk (commodity prices and interest rates), credit risk and liquidity risk.

Commodity Price Risk

Commodity price risk is the risk the Company will encounter fluctuations in future royalty production revenues with changes in commodity prices. Commodity prices for crude oil, NGL and natural gas are influenced by global and regional factors, including levels of supply and demand, weather and geopolitical factors. The Company has not hedged its commodity price risk.

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the fair value or future cash flows from the Company's financial assets or liabilities. The Company has minimal interest rate risk as it is only drawn $0.5 million on its Credit Facility.

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. The Company's diversified revenue stream limits the size of any one property or industry operator with respect to total receivables.

The Company maintains a compliance program to ensure royalties are paid correctly on production from the Royalty Properties in accordance with the terms of the agreements. This includes reviewing and analyzing prices obtained by the royalty payor and ensuring that unwarranted or excessive deductions are not being taken.

A substantial portion of the Company's accounts receivable are from leases, overriding royalties and other agreements with oil and gas industry operators and are subject to normal industry credit risks. The Company's leasing arrangements typically provide for termination of the lease in the event of non-payment of royalties which would result in a return of the petroleum and natural gas rights to the Company. In addition, the Company actively reviews its counterparties and takes its production in-kind to mitigate credit risk as appropriate.

As at September 30, 2018, there was one counterparty whose accounts receivable individually accounted for more than 10% of the total accounts receivable balance. The maximum credit risk exposure associated with accounts receivable and accrued revenue is the total carrying value. For the nine months ended September 30, 2018, the Company has provided an allowance for doubtful accounts of $1.0 million

(September 30, 2017 - $nil) calculated using an expected credit loss assessment for specifically identifiable customer balances which are assessed to have credit risk exposure.

Liquidity Risk

Liquidity risk is the risk that the Company will encounter difficulties funding its financial liabilities as they come due. Liquidity risk is managed by maintaining sufficient liquid financial resources to fund obligations as they come due. At September 30, 2018, the Company had working capital of $10.6 million. The Company also has access to funding alternatives through its Credit Facility.

The Company's sources of liquidity include cash and cash equivalents, working capital funds and its Credit Facility. The primary uses of funds are acquisitions, administrative expenses, production and mineral taxes, income taxes, dividends, and the repurchase and cancellation of PrairieSky common shares.

The timing of expected cash outflows relating to bank debt of $0.5 million, accounts payable and accrued liabilities of $12.8 million, income tax payable of $2.5 million and the dividend payable of $15.2 million is less than one year. Included in accounts payable and accrued liabilities is $2.6 million related to vested DSUs which may or may not be cash settled in the next year.

The Company's royalty production volumes and resultant revenues with high operating netbacks provide significant liquidity. The Company's dividend, common share repurchases and capital commitments are discretionary.

FURTHER INFORMATION ON RISK FACTORS AND INDUSTRY CONDITIONS

For a detailed discussion of the risks, uncertainties and industry conditions associated with PrairieSky's business, refer to PrairieSky's Annual Information Form dated February 26, 2018 which is available under PrairieSky's SEDAR profile at www.sedar.com and at www.prairiesky.com.

ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

ACCOUNTING JUDGMENTS AND ESTIMATES

Certain of the Company's accounting policies require subjective judgment about uncertain circumstances. The potential effect of these estimates, as described in the Company's 2017 Annual MD&A, have not changed during the current period. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

ACCOUNTING POLICY CHANGES

IFRS 15

The Company adopted IFRS 15, "Revenue from Contracts with Customers" on January 1, 2018. PrairieSky used the modified retrospective adoption approach to adopt the new standard. The Company reviewed its revenue streams and major contracts with customers using the IFRS 15 five-step model and there were no material changes to net earnings or the timing of royalty production revenue or other revenues recognized. Under this method, there was no effect to opening deficit from the application of IFRS 15 to revenue contracts in progress at January 1, 2018.

PrairieSky receives royalties from third party development of petroleum and natural gas pursuant to lease agreements on its fee simple lands. PrairieSky also collects royalties on production from GORR Interests that are tied to an underlying mineral lease.

The continuation of a lease is typically dependent on the holder thereof continuing to produce hydrocarbons and maintaining the lease in good standing. Accordingly, PrairieSky's performance obligations with respect to production royalties are satisfied over time, as petroleum and natural gas are produced.

Royalty revenue from the sale of crude oil, NGL and natural gas is recognized as it accrues in accordance with the terms of the royalty agreement, which is generally in the month when the product is produced with production volumes primarily marketed with lessees' production. Revenue for royalty production that is taken in-kind is recognized when the performance obligations are met, which is when control of the product is transferred to the buyer and legal title is transferred to the external party. Royalty revenue is measured at fair value of the consideration received or receivable when management can reliably estimate the amount, pursuant to the terms of the royalty agreements. An accrual is included in revenue and accounts receivable for amounts not received during the month of production based on historical trends, new wells on stream and current market prices. Differences between the estimates and actual amounts received are adjusted and recorded in the period when the actual amounts are received.

Other revenue is comprised of non-royalty production revenue, including revenue generated from lease rentals and mineral lease bonus consideration received when new leases are negotiated. The Company generates bonus consideration by leasing its mineral interests to exploration and production companies. Bonus consideration for new leases and lease rentals for the term of the initial lease ("primary term") are recognized as revenue when the lease agreement is executed, payment is determined to be collectible, and the Company has no obligation to refund the payment. When a lease is extended past the primary term, lease rental payments are due and recognized annually on the anniversary of the lease execution.

IFRS 9

The Company adopted IFRS 9, "Financial Instruments" on January 1, 2018. The transition to IFRS 9 had no material effect on the Company's financial statements.

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income ("FVOCI"), or fair value through profit or loss ("FVTPL"). The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics. IFRS 9 eliminates the previous IFRS 39 categories of held to maturity, loans and receivables and available for sale. Under IFRS 9, derivatives embedded in contracts where the host is a financial asset in the scope of the standard are never separated. Instead, the hybrid financial instrument as a whole is assessed for classification.

Impairment of financial assets: IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected credit loss" model. The new impairment model applies to financial assets measured at amortized cost, and contract assets and debt investments at FVOCI. Under IFRS 9, credit losses are recognized earlier than under IAS 39.

Cash and cash equivalents and accounts receivable and accrued revenue continue to be measured at amortized cost and are now classified as "amortized cost". There was no change to the Company's classification of accounts payable and accrued liabilities, bank debt and dividends payable which are classified as "other financial liabilities" and are measured at amortized cost. The Company has not designated any financial instruments as FVOCI or FVTPL, nor does the Company use hedge accounting.

RECENT ACCOUNTING PRONOUNCEMENTS

New Standards Issued Not Yet Adopted

On January 13, 2016, the IASB issued IFRS 16, "Leases" which replaces IAS 17 "Leases". The standard is required to be adopted either retrospectively or by recognizing the cumulative effect of initially applying IFRS 16 as an adjustment to opening equity at the date of initial application. IFRS 16 is effective for fiscal years beginning on or after January 1, 2019. Under the new standard, companies will recognize new assets and liabilities, bringing off-balance sheet leasing arrangements with a term of more than 12 months onto the balance sheet unless the underlying asset is of low value. The Company's mineral leases are not within the scope of IFRS 16. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The Company does not expect the standard to have a material impact on the financial statements.

CONTROL ENVIRONMENT

PrairieSky is required to comply with Multilateral Instrument 52-109 "Certification of Disclosure on Issuers' Annual and Interim Filings". The certification of interim filings for the interim period ended September 30, 2018, requires that PrairieSky disclose in the interim MD&A any changes in PrairieSky's internal controls over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect PrairieSky's internal controls over financial reporting. PrairieSky confirms that no such changes were identified in the Company's internal controls over financial reporting during the three-month period beginning on July 1, 2018 and ending on September 30, 2018.

SUMMARY OF QUARTERLY RESULTS AND TRENDS

(millions, unless otherwise noted)	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Q1 2018	Q2 2018	Q3 2018
FINANCIAL								
Royalty Revenue	$ 62.8	$ 73.5	$ 69.0	$ 54.2	$ 69.2	$ 64.1	$ 70.1	**$ 71.4**
Other Revenue	5.1	6.8	33.2	17.5	22.3	3.8	6.1	**6.7**
Total Revenues	67.9	80.3	102.2	71.7	91.5	67.9	76.2	**78.1**
Funds from Operations	61.8	67.3	75.0	66.8	81.1	51.8	62.4	**67.0**
Per Share – basic(1)(2)	0.27	0.28	0.32	0.28	0.34	0.22	0.27	**0.29**
Per Share - diluted(1)(2)	0.27	0.28	0.32	0.28	0.34	0.22	0.26	**0.28**
Net Earnings and Comprehensive Income	16.1	20.8	40.5	19.4	39.9	19.8	25.1	**28.5**
Per Share – basic and diluted(1)	0.07	0.09	0.17	0.08	0.17	0.08	0.11	**0.12**
Dividends Declared(3)	41.1	43.2	44.5	44.3	44.2	44.7	45.9	**45.8**
Per Share	0.1800	0.1825	0.1875	0.1875	0.1875	0.1900	0.1950	**0.1950**
Working Capital at Period End	44.2	97.6	108.0	98.7	45.7	17.3	21.1	**10.6**
OPERATIONAL								
Production Volumes								
Crude Oil (bbls/d)	8,583	10,214	9,609	9,033	9,419	8,731	9,098	**9,018**
NGL (bbls/d)	2,362	2,998	2,664	2,600	2,454	2,388	2,279	**2,503**
Natural Gas (MMcf/d)	78.2	81.6	80.6	75.3	75.2	74.5	69.4	**71.5**
Total (BOE/d)(4)	23,978	26,812	25,706	24,183	24,406	23,536	22,944	**23,438**

(1) Net Earnings and Comprehensive Income and Funds from Operations per Share are calculated using the weighted average number of common shares outstanding.
(2) A Non-GAAP measure, which is defined under the "Non-GAAP Measures" section of this MD&A.
(3) A dividend of $0.065 per common share was declared on September 10, 2018. The dividend was paid on October 15, 2018 to shareholders of record on September 28, 2018.
(4) See "Conversions of Natural Gas to BOE".

Quarterly variances in revenues, net earnings, and funds from operations are primarily due to fluctuations in commodity prices, production volumes, and bonus consideration. Crude oil prices are generally determined by global supply and demand factors. Natural gas prices are influenced by many variables including weather conditions, industrial demand, and North American natural gas inventories. Changes in the USD-CAD currency exchange rate impact the Company's oil revenue realization relative to benchmark WTI, which is referenced in US dollars.

The Company's financial results over past quarters were influenced by the following trends in commodity pricing:

- The WTI quarterly average of US$68.81 per bbl in Q3 2018 has increased 43% from US$48.15 per bbl in Q3 2017.
- Average realized NGL price of $37.32 per bbl in Q3 2018 has increased 49% from $25.02 per bbl in Q3 2017.
- The AECO monthly index quarterly average price of $1.35 per mcf in Q3 2018 has decreased 34% from $2.05 per mcf in Q3 2017.
- Average total realized price of $33.11 per BOE in Q3 2018 has increased 36% from $24.36 per BOE in Q3 2017.

Revenues improved through the first half of 2017 as a result of increases in commodity pricing and increases to production from acquisitions and incremental drilling on PrairieSky lands. Q1 and Q2 2017 royalty production volumes were also positively impacted by additional compliance recoveries. Also contributing to the higher revenues in Q2 2017 was $29.5 million in bonus consideration, an increase from $3.0 million in Q1 2017. Revenues in Q3 2017 decreased as a result of a decline in bonus consideration to $15.5 million as well as reductions in royalty production and realized pricing compared to Q2 2017. Revenues and funds from operations in Q4 2017 increased compared to Q3 2017 due to recoveries in commodity pricing and an increase in bonus consideration to $19.0 million. Both revenues and funds from operations declined in Q1 2018 as a result of a decrease in royalty production volumes and bonus consideration compared to Q4 2017; however, both of these metrics improved in Q2 2018 and further in Q3 2018 due to stronger benchmark pricing for crude oil and increased liquids volumes, partially offset by lower natural gas pricing.

Q4 2016 through Q2 2017, net earnings increased due to higher royalty revenues as a result of improved commodity prices and royalty production volumes as discussed above. Higher bonus consideration in Q2 2017 also positively impacted net earnings. Q3 2017 was affected by a reduction in bonus consideration, production volumes and realized pricing compared to Q2 2017. During Q4 2017, commodity pricing recovered and depletion was reduced due to additional reserves realized through acquisitions and 2017 incremental drilling. Q1 2018 net earnings and comprehensive income was affected by a reduction in royalty volumes as a result of natural declines and decreased bonus consideration compared to Q4 2017, before a recovery in Q2 2018 and Q3 2018 driven by recovering liquids pricing and increased liquids volumes.

Dividends declared in Q1 2017 increased as a result of the issuance of 9.2 million common shares under a bought deal prospectus offering in January 2017 which resulted in a higher total dividend. The monthly declared dividend was increased to $0.0625 per common share for the March 2017 record date. In February 2018, the dividend was further increased to $0.065 per common share for the March 2018 record date, thus increasing the dividend declared in Q2 2018 and Q3 2018.

In Q1 2017, a bought deal offering of 9.2 million common shares was completed for net cash proceeds of $276.9 million which was used primarily to fund the Lindbergh Acquisition for $250 million. Working capital continued to increase in Q2 2017 as a result of funds from operations exceeding the dividend and NCIB purchases. Working capital decreased in Q4 2017 and Q1 2018 as a result of cash acquisitions completed in the periods for $78.2 million and $21.2 million, respectively. Additional working capital was built in Q2 2018 as a result of excess cash flow generated from operations during Q2 2018. During Q3 2018, $19.5 million was spent on producing and non-producing royalties, seismic and undeveloped land, reducing the working capital balance at the end of Q3 2018 to $10.6 million.

NON-GAAP MEASURES

Certain measures in this MD&A do not have any standardized meaning as prescribed by IFRS and therefore, are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures are commonly used in the oil and gas industry and by the Company to provide potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Non-GAAP measures include Operating Netback, Operating Netback per BOE and Funds from Operations per Share – basic and diluted. Management's use of these measures is discussed further below.

"Operating Netback" represents the cash margin for products sold. Operating Netback is calculated as royalty revenues less production and mineral taxes and administrative expenses. Operating Netback provides a consistent measure of the cash generating performance of the Royalty Properties to assess the comparability of the underlying performance between years.

"Operating Netback per BOE" represents the cash margin for products sold on a BOE basis. Operating Netback per BOE is calculated by dividing the Operating Netback by the production volumes for the period. Operating Netback per BOE is used to assess the cash generating performance per unit of product sold. Operating Netback per BOE measures are commonly used in the oil and gas industry to assess performance comparability. Refer to the Operating Results table in this MD&A document for a summary of this reporting period's Operating Netback calculations.

"Funds from Operations per Share" are calculated on a weighted average basis using basic and diluted common shares outstanding during the period. This measure, together with other measures, are used by the investment community to assess the source, sustainability and cash available for dividends and share repurchases.

ADVISORY

FORWARD-LOOKING STATEMENTS

This MD&A includes certain statements regarding PrairieSky's future plans and operations as at October 29, 2018, and contains forward-looking statements that we believe allow readers to better understand our business and prospects. Forward-looking statements contained in this MD&A include our expectations with respect to the following:

- commodity prices including supply and demand factors relating to crude oil, natural gas and NGL;
- expected future commitments and payments related thereto;
- PrairieSky's business and growth strategy and anticipated sources of future income;
- PrairieSky's dividend policy and its intention to distribute the majority of cash flow as dividends to shareholders over time, which intention could change with little or no notice;
- PrairieSky's normal course issuer bid and specifically the volume and value of future repurchases under the normal course issuer bid;
- the manner in which PrairieSky manages collection and credit risk and its belief that the diversity of payors and products mitigate this risk;
- possible revisions to accrued estimates based on receipt of actual results;
- impact of compliance activities and recoveries, which vary quarterly;
- impact of bonus consideration, which varies quarterly;
- impact of PrairieSky's share price on administrative expenses;
- expected impacts of accounting standards, including those announced but not yet adopted;
- the expectation that there will be no operating costs, capital costs, environmental liabilities, or abandonment and reclamation obligations associated with development of the Royalty Properties;
- changes to the legislative and regulatory frameworks in the jurisdictions in which the Company carries on a business;

- the ability to mitigate the risks of fluctuations in commodity prices and production volumes, including but not limited to impacts from a slowdown in both natural gas drilling and workover activity and ethane curtailments; and
- average production and contribution from the Royalty Properties including the impact of declines.

By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, lack of pipeline capacity, currency fluctuations, imprecision of reserve estimates, royalties, environmental risks, taxation, regulation, changes in tax or other legislation, political and geopolitical instability, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, and our ability to access sufficient capital from internal and external sources. In addition, PrairieSky is subject to numerous risks and uncertainties in relation to acquisitions. These risks and uncertainties include risks relating to title to the assets acquired and the potential for disputes to arise with third parties, and limited ability to recover indemnification from such third parties under certain agreements. The foregoing and other risks are described in more detail in PrairieSky's Annual Information Form and in this MD&A under the heading "Risk Management".

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things, the ability of the lessees and working interest owners on the Royalty Properties to maintain or increase production and reserves from these properties; the ability and willingness of the lessees and working interest owners on the Royalty Properties to comply with, and PrairieSky to enforce, lease terms and contractual provisions, as applicable, in order to receive payments; the ability of the lessees or working interest owners on the Royalty Properties to operate in a safe, efficient and effective manner; the timely receipt of any required regulatory approvals by lessees or working interest owners on the Royalty Properties; the willingness and financial capability of the lessees and working interest owners to continue to develop and invest additional capital in the Royalty Properties; the ability of the lessees and working interest owners on the Royalty Properties to obtain financing on acceptable terms to fund capital expenditures; field production rates, decline rates and the well performance and characteristics of the Royalty Properties; the ability to replace and increase crude oil, natural gas and NGL reserves and production associated with the Royalty Properties through third-party development and complementary acquisitions; the timing, cost and ability of third parties to access, maintain or expand necessary facilities and/or secure adequate product transportation and storage; the ability of the operators of the properties in which PrairieSky has a royalty interest in, to successfully market their respective petroleum and natural gas products or, for royalty payments taken-in-kind by PrairieSky, the ability of PrairieSky or a third-party marketer to successfully market PrairieSky's in-kind petroleum and natural gas products; surface rights access being granted to third parties on PrairieSky's properties; the benefits of the seismic data anticipated to be used by PrairieSky and sub-licensed to lessees on the PrairieSky's properties; the level of costs and expenses to be incurred by PrairieSky, including with respect to interest, administrative expenses and income taxes; the ability of PrairieSky to obtain and retain qualified staff and services in a timely and cost efficient manner; the absence of any material litigation or claims against or involving PrairieSky; the general stability of the economic and political environment and the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which PrairieSky has an interest in crude oil and natural gas properties; future crude oil, natural gas and NGL prices and currency, exchange and interest rates; and PrairieSky's ability execute the volume and/or value of purchases as described under the normal course issuer bid.

Readers are cautioned that the assumptions used in the preparation of such forward-looking information and statements, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive.

Any forward-looking statement is made only as of the date of this MD&A, and PrairieSky undertakes no obligation to update or revise any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws. New factors emerge from time to time, and it is not possible for PrairieSky to predict all of these factors or to assess in advance the impact of each such factor on PrairieSky's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement.

You are further cautioned that the preparation of consolidated financial statements in accordance with IFRS requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. These estimates may change, having either a positive or negative effect on net earnings, as further information becomes available and as the economic environment changes.

CONVERSIONS OF NATURAL GAS TO BOE

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (BOE). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 BOE ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the BOE ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio, based on the current price of crude oil to natural gas, is significantly different from the 6:1 energy equivalency ratio, using a 6:1 conversion ratio may be misleading as an indication of value.

CURRENCY AND REFERENCES TO PRAIRIESKY

All information included in this MD&A, and the interim condensed consolidated financial statements is shown on a Canadian dollar basis.

For convenience, references in this document to the "Company", "we", "us", "our", and "its" may, where applicable, refer only to PrairieSky.

ADDITIONAL INFORMATION

Additional information about PrairieSky, including the 2017 audited annual consolidated financial statements and notes thereto, and PrairieSky's Annual Information Form, is available on SEDAR at www.sedar.com or PrairieSky's website at www.prairiesky.com.