MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED
DECEMBER 31, 2020

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PRAIRIESKY ROYALTY LTD

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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 audited annual consolidated financial statements as at and for the years ended December 31, 2020 and 2019 ("financial statements"). This MD&A has been prepared as of February 8, 2021.

The 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, Operating Margin, Cash Administrative Expenses, and Cash Administrative Expenses per BOE. 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, crude 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 December 31 2020	Three months ended December 31 2019	Year ended December 31 2020	Year ended December 31 2019
FINANCIAL				
Revenues	**$ 47.0**	$ 67.1	**$ 171.4**	$ 268.4
Funds from Operations	**41.1**	55.8	**146.8**	220.4
Per Share - basic and diluted(1)	**0.18**	0.24	**0.64**	0.94
Net Earnings	**14.1**	24.3	**31.7**	111.4
Per Share - basic and diluted(1)	**0.06**	0.10	**0.14**	0.48
Dividends declared(2)	**13.4**	45.4	**86.1**	182.1
Per Share	**0.0600**	0.1950	**0.3750**	0.7800
Common share repurchases	**-**	2.8	**90.9**	19.0
Acquisitions, including non-cash consideration	**2.7**	3.4	**9.4**	11.2
Working Capital (Deficiency) at period end	**(42.0)**	(3.1)	**(42.0)**	(3.1)
Shares outstanding				
Shares outstanding at period end	**223.3**	233.1	**223.3**	233.1
Weighted average - basic	**223.3**	233.2	**229.6**	233.6
Weighted average - diluted	**223.8**	233.6	**230.1**	234.0
OPERATIONAL				
Royalty Production Volumes				
Crude Oil (bbls/d)	**7,313**	8,884	**7,124**	8,633
NGL (bbls/d)	**2,285**	2,819	**2,571**	2,607
Natural Gas (MMcf/d)	**58.1**	63.0	**60.1**	63.1
Royalty Production (BOE/d)(3)	**19,281**	22,203	**19,712**	21,757
Realized Pricing				
Crude Oil ($/bbl)	**41.59**	57.29	**38.05**	59.88
NGL ($/bbl)	**26.44**	25.92	**22.93**	28.02
Natural Gas ($/Mcf)	**1.87**	1.70	**1.61**	1.28
Total ($/BOE)(3)	**24.58**	31.04	**21.65**	30.84
Operating Netback per BOE(4)	**$ 22.10**	$ 28.39	**$ 18.81**	$ 27.58
Funds from Operations per BOE	**$ 23.17**	$ 27.32	**$ 20.35**	$ 27.75
Oil Price Benchmarks				
West Texas Intermediate (WTI) (US$/bbl)	**42.66**	56.96	**39.40**	57.03
Edmonton Light Sweet ($/bbl)	**50.24**	68.10	**45.34**	69.22
Western Canadian Select (WCS) crude oil differential to WTI (US$/bbl)	**(9.30)**	(15.84)	**(12.60)**	(12.76)
Natural Gas Price Benchmark				
AECO monthly index ($/Mcf)	**2.76**	2.31	**2.24**	1.62
AECO daily index ($/Mcf)	**2.64**	2.47	**2.23**	1.76
Foreign Exchange Rate (US$/CAD$)	**0.7694**	0.7575	**0.7468**	0.7537

(1) Net Earnings and Funds from Operations per Share are calculated using the weighted average number of basic and diluted common shares outstanding.
(2) A dividend of $0.06 per common share was declared on December 7, 2020. The dividend was paid on January 15, 2021 to shareholders of record as at December 31, 2020.
(3) See "Conversions of Natural Gas to BOE".
(4) Operating Netback per BOE is defined under the Non-GAAP Measures section in this MD&A.

Results Overview

HIGHLIGHTS

Highlights of PrairieSky's financial results for the three months ended December 31, 2020 ("Q4 2020") include:

- Revenues totaled $47.0 million, consisting of $43.6 million of royalty production revenue, $1.8 million of lease rental income, $0.9 million of bonus consideration and $0.7 million of other income.
- Funds from operations totaled $41.1 million ($0.18 per share basic and diluted).
- Royalty production averaged 19,281 BOE per day (50% liquids) consisting of average crude oil royalty production volumes of 7,313 bbls per day, average NGL royalty production volumes of 2,285 bbls per day and average natural gas royalty production volumes of 58.1 MMcf per day.
- Dividends declared of $13.4 million ($0.06 per share).

Highlights of PrairieSky's financial results for the year ended December 31, 2020 ("YE 2020") include:

- Revenues totaled $171.4 million, consisting of $156.2 million of royalty production revenue, $5.9 million of lease rental income, $5.8 million of bonus consideration and $3.5 million of other income.
- Funds from operations totaled $146.8 million ($0.64 per share basic and diluted).
- Royalty production averaged 19,712 BOE per day (49% liquids) consisting of average crude oil royalty production volumes of 7,124 bbls per day, average NGL royalty production volumes of 2,571 bbls per day and average natural gas royalty production volumes of 60.1 MMcf per day.
- Dividends declared of $86.1 million ($0.3750 per share).
- Purchased for cancellation 9,770,691 common shares at a weighted average price of $9.30 per common share for total consideration of $90.9 million under the normal course issuer bid ("NCIB").

PRAIRIESKY'S 2021 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 novel coronavirus (COVID-19) pandemic significantly impacted the global economy in 2020, as large-scale restrictions put in place to prevent its spread, created market volatility and a dramatic decrease in global oil demand. This decrease combined with instability for crude oil pricing initiated in March 2020 by global participants impacted both cash flows in the energy industry and access to capital. Canadian oil and gas operators responded by shutting in production in the second quarter and reducing their capital budgets and spending. During the second half of 2020, the majority of shut-in production gradually resumed, and crude oil pricing improved. Natural gas pricing has remained relatively stable, which has been positive for PrairieSky and third-party natural gas producers.

The path towards a full economic recovery is challenging to forecast, with the overall outlook on crude oil demand largely dependent on the status of COVID-19 and the spread of variants, vaccine rollouts, changes to social restrictions and businesses resuming regular operations. Benchmark crude oil pricing has positively responded to global participants maintaining, and in certain cases increasing, production cuts but overall uncertainty remains. Management continues to monitor current commodity prices, currency exchange rates, industry activity levels and third-party anticipated capital expenditures for 2021 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 Strategy

The Company's objective is to generate significant cash flow and returns for shareholders through indirect crude oil and natural 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.

PrairieSky remains confident in its strategy and business model which provides robust operating margins in all commodity cycles. 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 has consistently maintained a strong balance sheet and employs a conservative capital structure. On February 8, 2021, the Company announced that the Board has increased the dividend by 8% to $0.26 per common share on an annualized basis ($0.065 per common share on a quarterly basis).

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 and approximately 7.7 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 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) crude oil and natural gas overriding royalty interests, gross overriding royalty interests, net profit interests and production payments on lands ("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 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, NGL or natural gas; rather, third-party development of the Royalty Properties provides the Company with royalty production revenues as petroleum, NGL and natural gas are produced from such properties. PrairieSky's operations include royalty income earned through crude oil, NGL and natural gas produced on the Royalty Properties. The Company's royalty production 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.

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/or 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 field operations, 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.

PrairieSky receives royalty production revenue from approximately 37,000 wells and receives payments from approximately 310 different industry payors. The Company receives approximately 75% of its monthly revenue from 30 payors. Royalties are calculated on a fixed percentage, step or sliding scale formula. Some royalty agreements allow for the deduction of certain handling, processing, and transportation costs.

As a royalty owner, PrairieSky does not bear the operational risks typically associated with the upstream petroleum 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.

Royalty Production

Royalty Production Volumes

	Three months ended December 31		Year ended December 31	
(Average daily)	**2020**	**2019**	**2020**	**2019**
Crude Oil (bbls/d)	**7,313**	8,884	**7,124**	8,633
NGL (bbls/d)	**2,285**	2,819	**2,571**	2,607
Natural Gas (MMcf/d)	**58.1**	63.0	**60.1**	63.1
Total Royalty Production (BOE/d)	**19,281**	22,203	**19,712**	21,757

PrairieSky's average daily royalty production volumes for Q4 2020 were 38% crude oil, 12% NGL and 50% natural gas as compared to the three months ended December 31, 2019 ("Q4 2019") when the royalty production volume split was 40% crude oil, 13% NGL and 47% natural gas. The average daily royalty production volume split for YE 2020 was 36% oil, 13% NGL and 51% natural gas as compared to the year ended December 31, 2019 ("YE 2019") when the average daily royalty production volume split was 40% crude oil, 12% NGL and 48% natural gas. There is a natural delay between the timing of production and when PrairieSky receives its royalty interest production volumes 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. PrairieSky's compliance department continually reviews leasing agreements and royalty calculations and collections related to compliance recoveries result in adjustments to royalty production volumes and royalty revenue related to prior periods. Compliance adjustments are not recorded in the financial statements until collection is received.

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 production 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.

For the three months ended December 31, 2020

Crude oil royalty production volumes for Q4 2020 of 7,313 bbls per day have decreased 18% from 8,884 bbls per day reported in Q4 2019. Royalty production decreased primarily as a result of lower exploration and development activity from third-party operators across Western Canada due to lower average WTI pricing, COVID-19 related government restrictions in place in Western Canada during parts of 2020, and the decrease in global oil demand as a result of the global pandemic. In addition, lower WTI benchmark pricing negatively impacted sliding scale royalty volumes compared to Q4 2019.

NGL royalty production volumes for Q4 2020 of 2,285 bbls per day have decreased 19% from 2,819 bbls per day reported in Q4 2019. Q4 2019 royalty production volumes included prior period adjustments that increased production that were not repeated in Q4 2020. In addition, natural declines more than offset new incremental production during Q4 2020.

Natural gas royalty production volumes for Q4 2020 of 58.1 MMcf per day were 8% lower than the 63.0 MMcf per day reported in Q4 2019 as natural declines and lower solution gas volumes from oil wells offset incremental production from new wells.

For the year ended December 31, 2020

Crude oil royalty production volumes for YE 2020 of 7,124 bbls per day decreased 17% from 8,633 bbls per day reported in YE 2019 primarily due to production shut-ins across Western Canada initiated in the second quarter, with the majority of production volumes gradually resuming through the second half of the year. In addition, the significant decrease in WTI benchmark pricing resulted in lower sliding scale royalty volumes, and more importantly, lower overall exploration and development activity across Western Canada which led to an aggregate natural decline in oil royalty production.

NGL royalty production volumes for YE 2020 of 2,571 bbls per day were in line with the 2,607 bbls per day reported in YE 2019 as royalty production volumes from new drilling on the Royalty Properties mostly offset natural declines.

Natural gas royalty production volumes for YE 2020 of 60.1 MMcf per day decreased 5% from 63.1 MMcf per day reported in YE 2019 as royalty production volumes from new drilling on the Royalty Properties were outweighed by natural declines and the impact of lower solution gas volumes from shut-in oil production.

Financial Results

Operating Results

	Three months ended December 31, 2020		**Three months ended December 31, 2019**	
	($ millions)	**($/BOE)[2]**	**($ millions)**	**($/BOE)[2]**
Royalty Production Revenue	**$ 43.6**	**$ 24.58**	$ 63.4	$ 31.04
Production and Mineral Taxes	**(0.9)**	**(0.51)**	(1.3)	(0.64)
Cash Administrative Expenses[1]	**(3.5)**	**(1.97)**	(4.1)	(2.01)
Operating Netback[1]	**39.2**	**22.10**	58.0	28.39
Operating Margin[1]	**90%**	**90%**	91%	91%

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

	Year ended December 31, 2020		**Year ended December 31, 2019**	
	($ millions)	**($/BOE)[2]**	**($ millions)**	**($/BOE)[2]**
Royalty Production Revenue	**$ 156.2**	**$ 21.65**	$ 244.9	$ 30.84
Production and Mineral Taxes	**(2.5)**	**(0.35)**	(4.6)	(0.58)
Cash Administrative Expenses[1]	**(18.0)**	**(2.49)**	(21.3)	(2.68)
Operating Netback[1]	**135.7**	**18.81**	219.0	27.58
Operating Margin[1]	**87%**	**87%**	89%	89%

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

The Q4 2020 operating netback of $39.2 million ($22.10 per BOE) decreased 32% from $58.0 million ($28.39 per BOE) in Q4 2019 primarily as a result of lower royalty production revenue and specifically lower benchmark pricing and production volumes for crude oil.

The YE 2020 operating netback of $135.7 million ($18.81 per BOE) decreased 38% from $219.0 million ($27.58 per BOE) in YE 2019 primarily as a result of lower royalty production revenue and specifically lower benchmark pricing and production volumes for crude oil, which was partially offset by increased benchmark pricing for natural gas.

Revenues

($ millions)	Three months ended December 31		Year ended December 31	
Royalty Production Revenue by Product	**2020**	**2019**	**2020**	**2019**
Crude Oil	**$ 28.0**	$ 46.9	**$ 99.2**	$ 188.7
NGL	**5.6**	6.7	**21.6**	26.7
Natural Gas	**10.0**	9.8	**35.4**	29.5
	43.6	63.4	**156.2**	244.9
Other Revenue				
Lease Rental Income	**$ 1.8**	$ 2.2	**$ 5.9**	$ 7.2
Bonus Consideration	**0.9**	1.4	**5.8**	12.1
Other Income	**0.7**	0.1	**3.5**	4.2
	3.4	3.7	**15.2**	$ 23.5
Total Revenues	**$ 47.0**	$ 67.1	**$ 171.4**	$ 268.4

($ millions)	Three months ended December 31		Year ended December 31	
Revenues by Classification	**2020**	**2019**	**2020**	**2019**
Lessor Interests on Fee Lands	**$ 28.0**	$ 42.0	**$ 98.5**	$ 162.0
GORR Interests	**15.6**	21.4	**57.7**	82.9
Royalty Production Revenue	**43.6**	63.4	**156.2**	244.9
Other Revenue	**3.4**	3.7	**15.2**	23.5
Total Revenues	**$ 47.0**	$ 67.1	**$ 171.4**	$ 268.4

	Three months ended December 31		Year ended December 31	
Pricing	**2020**	**2019**	**2020**	**2019**
Benchmark				
WTI (US$/bbl)	**42.66**	56.96	**39.40**	57.03
Edmonton Light Sweet ($/bbl)	**50.24**	68.10	**45.34**	69.22
WCS Differential to WTI (US$/bbl)	**(9.30)**	(15.84)	**(12.60)**	(12.76)
AECO Monthly Index ($/Mcf)	**2.76**	2.31	**2.24**	1.62
AECO Daily Index ($/Mcf)	**2.64**	2.47	**2.23**	1.76
Foreign Exchange Rate (US$/CAD$)	**0.7694**	0.7575	**0.7468**	0.7537

	Three months ended December 31		Year ended December 31	
Realized Pricing	**2020**	**2019**	**2020**	**2019**
Crude Oil ($/bbl)	**41.59**	57.29	**38.05**	59.88
NGL ($/bbl)	**26.44**	25.92	**22.93**	28.02
Natural Gas ($/Mcf)	**1.87**	1.70	**1.61**	1.28
Total ($/BOE)	**24.58**	31.04	**21.65**	30.84

The Company's average royalty rate for all producing wells on the Royalty Properties in Q4 2020 and Q4 2019 was approximately 6.0%. During Q4 2020, royalty production revenue was $43.6 million compared to $63.4 million for the same period in 2019, a decrease of 31%. The decrease in royalty production revenue was primarily due to the 25% decrease in WTI benchmark pricing between the two quarters. The significant decrease in pricing also resulted in third-party operators shutting in production and reducing exploration and development activity which lowered the Company's royalty production volumes.

During Q4 2020, revenue from Lessor Interests on Fee Lands was $28.0 million or 64% of total royalty production revenue. Revenue from GORR Interests was $15.6 million or 36% of total royalty production revenue for the same period. In the comparative period, $42.0 million or 66% of royalty production revenue was generated from Lessor Interests on Fee Lands and $21.4 million or 34% from GORR Interests. In addition to royalty revenue from Lessor Interests, all lease rental income and bonus consideration are generated from Fee Lands.

During YE 2020, royalty production revenue was $156.2 million, a 36% decrease compared to $244.9 million for the same period in 2019. The decrease in royalty production revenue was primarily due to the 31% decrease in WTI benchmark oil pricing and lower oil royalty production volumes due to shut-in production and reduced third-party exploration and development activity.

During YE 2020, revenue from the Lessor Interests was $98.5 million or 63% of total royalty production revenue. Revenue from GORR Interests was $57.7 million or 37% of total royalty production revenue for the same period. In the comparative period, $162.0 million or 66% and $82.9 million or 34% of royalty production revenue was generated from Lessor Interests and GORR Interests, respectively. 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 Interests acquired over multiple years, and increased activity on GORR Lands.

During Q4 2020, the Company averaged realized crude oil pricing of $41.59 per bbl, NGL pricing of $26.44 per bbl and natural gas pricing of $1.87 per Mcf. Average realized pricing for crude oil decreased from Q4 2019 when the Company averaged realized crude oil pricing of $57.29 per bbl. Average realized pricing for crude oil was negatively impacted by a 25% decrease in benchmark WTI pricing as a result of global supply and demand disruptions. This decrease was partially offset by narrower Canadian light and heavy oil differentials. Average realized NGL pricing in Q4 2020 was relatively flat at $26.44 per bbl as compared to $25.92 for Q4 2019 as higher benchmark pricing for propane and improved propane and butane differentials under the current NGL contract year offset the impact of lower WTI benchmark pricing. Average realized natural gas pricing increased to $1.87 per Mcf in Q4 2020 from $1.70 per Mcf in Q4 2019 due to stronger AECO and Station 2 benchmark pricing.

For YE 2020, the Company averaged realized crude oil pricing of $38.05 per bbl and NGL pricing of $22.93 per bbl. Realized pricing for liquids production decreased compared to YE 2019 when the Company averaged realized crude oil pricing of $59.88 per bbl and NGL pricing of $28.02 per bbl primarily as a result of the 31% decline in the average benchmark WTI price due to global supply and demand disruptions. Average NGL realized pricing, as a percentage of benchmark pricing, was positively impacted by improved propane and butane differentials under the current NGL contract year. Higher average AECO and Station 2 benchmark pricing, primarily due to improved egress in Alberta and the ability to access storage, resulted in improved average realized natural gas pricing for YE 2020 of $1.61 per Mcf, a 26% increase from $1.28 per Mcf in YE 2019.

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 of outstanding amounts is received. For Q4 2020 and YE 2020, the Company collected $0.8 million (Q4 2019 - $1.6 million) and $5.8 million (YE 2019 - $7.2 million), respectively, in compliance recoveries. Compliance recoveries are included in royalty production revenue in the period in which they are received.

Other revenue consisted primarily of lease rental income and lease bonus consideration from new leasing arrangements as well as leases currently issued in respect of certain Fee Lands. Lease rental income for Q4 2020 and YE 2020 was $1.8 million (Q4 2019 - $2.2 million) and $5.9 million (YE 2019 - $7.2 million), respectively. Bonus consideration revenue for Q4 2020 and YE 2020 was $0.9 million (Q4 2019 - $1.4 million) and $5.8 million (YE 2019 - $12.1 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. Other income was $0.7 million for Q4 2020 (Q4 2019 - $0.1 million) and $3.5 million for YE 2020 (YE 2019 - $4.2 million) and primarily related to the collection of non-performance fees for YE 2020.

Administrative Expenses

($ millions)	Three months ended December 31 2020	2019	Year ended December 31 2020	2019
Salaries and Benefits	**$ 2.3**	$ 3.0	**$ 10.5**	$ 12.9
Share-Based Compensation	**1.4**	(1.0)	**2.3**	4.6
Office Expense	**0.6**	0.6	**2.4**	2.6
Public Company Expense	**0.1**	0.2	**1.4**	1.5
Information Technology and Other	**0.5**	0.3	**2.0**	2.1
Total Administrative Expenses	**$ 4.9**	$ 3.1	**$ 18.6**	$ 23.7
Administrative Expenses per BOE[(1)]	**$ 2.76**	$ 1.52	**$ 2.58**	$ 2.98
Cash Administrative Expenses[(2)]	**$ 3.5**	$ 4.1	**$ 18.0**	$ 21.3
Cash Administrative Expenses per BOE[(1)(2)]	**$ 1.97**	$ 2.01	**$ 2.49**	$ 2.68

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

PrairieSky is committed to controlling costs, finding efficiencies and optimizing technology across the business. Administrative expenses for Q4 2020 and YE 2020 were $2.76 per BOE (Q4 2019 - $1.52 per BOE) and $2.58 per BOE (YE 2019 - $2.98 per BOE), respectively. Administrative expenses include both cash and non-cash charges which relate to share-based compensation plans. Administrative expenses related to restricted share units ("RSUs"), preferred share units ("PSUs"), officer deferred share units ("ODSUs"), and deferred share units for Directors ("DSUs") are impacted by the closing share price at period end and as such, are subject to variability.

Cash administrative expenses of $3.5 million ($1.97 per BOE) for Q4 2020 were down 15% from Q4 2019 cash administrative expenses of $4.1 million ($2.01 per BOE) primarily as a result of reduced officer and employee compensation and the receipt of the Canadian Emergency Wage Subsidy ("CEWS") which was put in place to support businesses as a result of COVID-19. Cash administrative expenses for YE 2020 were $18.0 million ($2.49 per BOE), a 15% decrease from YE 2019 cash administrative expenses of $21.3 million ($2.68 per BOE) primarily as a result of the effect of a decreased share price on the settlement of share-based compensation plans that occurs in the first quarter of each year and receipt of the CEWS as discussed above.

The Company has chosen to no longer participate in the CEWS program effective January 1, 2021 and does not anticipate receiving any CEWS amounts in respect to the 2021 fiscal period.

Company payouts related to share-based compensation for the entire organization, including executives, during Q4 2020 were $nil (Q4 2019 - $nil) and $1.7 million during YE 2020 (YE 2019 - $2.2 million). When cash share-based payments are made, there is an increase in cash administrative expenses in the period. Cash payments decreased in YE 2020 as compared to YE 2019 due to lower pricing used in the calculation of the payout under the RSU and PSU plans in the current year, as well as a lower performance factor related to the PSUs.

($ millions) Share-Based Compensation	Three months ended December 31 2020	2019	Year ended December 31 2020	2019
Stock Option Expense	**$ 0.3**	$ 0.4	**$ 1.1**	$ 1.8
PSU Expense (Recovery)	**0.2**	(1.1)	**0.6**	1.1
RSU Expense	**0.3**	0.1	**0.5**	1.0
ODSU Expense	**0.1**	-	**0.2**	-
DSU Expense (Recovery)	**0.5**	(0.4)	**(0.1)**	0.7
Total Share-Based Compensation Expense (Recovery)	**$ 1.4**	$ (1.0)	**$ 2.3**	$ 4.6

Share-based compensation expense is impacted by the closing share price at period end. The expense recorded in Q4 2020 was higher than in Q4 2019 due to changes in the share price and fluctuations in the performance factor related to PSUs.

Share-based compensation expense for YE 2020 is lower than YE 2019 as the decrease in the share price from December 31, 2019 to December 31, 2020 resulted in a recovery of a portion of expense previously incurred, which partially offset the expense related to new grants. Total outstanding units and options from all employee, officer, and director incentive plans is less than 1.0% of total common shares outstanding at December 31, 2020.

Production and Mineral Taxes

	Three months ended December 31		Year ended December 31	
($ millions, except per BOE amounts)	**2020**	**2019**	**2020**	**2019**
Production and Mineral Taxes	**$ 0.9**	$ 1.3	**$ 2.5**	$ 4.6
$/BOE(1)	**$ 0.51**	$ 0.64	**$ 0.35**	$ 0.58

(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 the amount of acreage from non-Crown lands. For Q4 2020 and Q4 2019, production and mineral taxes, which includes Alberta Freehold Mineral Tax and Saskatchewan acreage tax, was 2.1% of royalty production revenue. YE 2020, production and mineral taxes totaled 1.6% of royalty production revenue compared to 1.9% in YE 2019. Saskatchewan acreage tax does not vary with commodity pricing while Alberta Freehold Mineral Tax is impacted by both production and commodity 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 December 31		Year ended December 31	
($ millions, except per BOE amounts)	**2020**	**2019**	**2020**	**2019**
Depletion, Depreciation and Amortization	**$ 23.2**	$ 30.8	**$ 104.5**	$ 123.2
$/BOE(1)	**$ 13.08**	$ 15.08	**$ 14.48**	$ 15.51

(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, including the right-of-use asset associated with the office lease, are depreciated on a straight-line basis. DD&A per BOE was lower in Q4 2020 and YE 2020 than the prior year comparative periods due to a lower depletable base and reserve additions. DD&A per BOE will fluctuate depending on the royalty assets acquired, if any, transfers to royalty assets from exploration and evaluation ("E&E") assets, the amount of reserves added, and production volumes in the period.

Exploration and Evaluation Expense

	Three months ended December 31		Year ended December 31	
($ millions, except per BOE amounts)	**2020**	**2019**	**2020**	**2019**
Exploration and Evaluation Expense	**$ 1.6**	$ 1.4	**$ 6.5**	$ 6.1
$/BOE(1)	**$ 0.90**	$ 0.69	**$ 0.90**	$ 0.77

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

During Q4 2020 and YE 2020, $1.6 million (Q4 2019 - $1.4 million) and $6.5 million (YE 2019 - $6.1 million), respectively, of costs associated with expired Crown mineral leases and GORR Interests were recognized as an expense. The expense will vary period to period as a result of the timing of lease expiries, if any.

Finance

Finance expense of $0.5 million in Q4 2020 has increased from $0.4 million in Q4 2019, as the increased bank debt balance offset the reduction in corporate interest rates. For YE 2020, finance expense decreased to $1.5 million from $1.6 million reported during YE 2019, as a result of the decrease in corporate interest rates during 2020 and the timing of the draw downs on the credit facility throughout the year.

Income Tax

($ millions)	Three months ended December 31 2020	2019	Year ended December 31 2020	2019
Current Tax Expense	**$ 1.0**	$ 5.5	**$ 2.7**	$ 19.4
Deferred Tax Expense (Recovery)	**0.8**	0.3	**3.4**	(21.6)
Income Tax Expense (Recovery)	**$ 1.8**	$ 5.8	**$ 6.1**	$ (2.2)

During Q4 2020, the Company recorded a $1.0 million (Q4 2019 - $5.5 million) current tax expense and a deferred tax expense of $0.8 million (Q4 2019 - $0.3 million). During YE 2020, the Company recorded a $2.7 million (YE 2019 - $19.4 million) current tax expense and a deferred tax expense of $3.4 million (YE 2019 - recovery of $21.6 million). The Company's effective tax rate differs from PrairieSky's combined Provincial and Federal statutory tax rate of 24.3% 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.

For the year ended December 31, 2020, the combined current and deferred tax rate expense includes $1.2 million attributable to the Alberta government's acceleration of the corporate income tax rate reduction to 8% as of July 1, 2020. Deferred tax for the year ended December 31, 2019, included a $25.5 million recovery as a result of the initial provincial income tax rate reduction that was to occur from 2020 to 2022.

The approximate tax pools balances available at year end are:

(millions)	Year ended December 31, 2020	Year ended December 31, 2019
Canadian oil and gas property expense ("COGPE")	**$ 1,165.8**	$ 1,292.2
Canadian development expense ("CDE")	**0.1**	0.1
Undepreciated capital cost ("UCC")	**0.4**	0.5
Share issue costs	**2.4**	4.8
	$ 1,168.7	$ 1,297.6

Net Earnings

The Company generated net earnings of $14.1 million ($0.06 per share, basic and diluted) for Q4 2020 and $31.7 million ($0.14 per share, basic and diluted) for YE 2020. Net earnings in the prior year were $24.3 million for Q4 2019 ($0.10 per share, basic and diluted) and $111.4 million for YE 2019 ($0.48 per share, basic and diluted). Net earnings for both periods in 2020 were lower than in 2019 primarily as a result of the decrease in royalty revenues as previously discussed, which were partially offset by lower DD&A expenses. YE 2019 also benefited from a $25.5 million deferred income tax recovery due to the reduction in Provincial income tax rates as noted above.

Acquisitions

During Q4 2020, the Company completed acquisitions totaling $2.7 million (Q4 2019 - $3.4 million) comprised of $2.5 million in royalty assets (Q4 2019 - $0.1 million), consisting of producing GORR Interests, and $0.2 million (Q4 2019 - $3.3 million) of E&E assets, consisting of royalty interests on non-producing properties and undeveloped land.

YE 2020, the Company completed acquisitions totaling $9.4 million (YE 2019 - $11.2 million) comprised of royalty assets of $7.2 million (YE 2019 - $0.2 million), which were primarily acquisitions of producing Fee Lands and GORR Interests, and E&E assets of $2.2 million (YE 2019 - $11.0 million) consisting of royalty interests on non-producing properties and undeveloped land.

Liquidity and Capital Resources

	Three months ended December 31		Year ended December 31	
($ millions)	**2020**	**2019**	**2020**	**2019**
Net Cash From (Used In)				
Operating Activities	**$ 39.5**	$ 52.0	**$ 152.3**	$ 209.7
Investing Activities	**(1.9)**	(5.9)	**(8.6)**	(10.0)
Financing Activities	**(37.6)**	(46.1)	**(143.7)**	(199.7)
Change in Cash and Cash Equivalents	**$ -**	$ -	**$ -**	$ -
Cash and Cash Equivalents, Beginning of Period	**$ -**	$ -	**$ -**	$ -
Cash and Cash Equivalents, End of Period	**$ -**	$ -	**$ -**	$ -

Operating Activities

Net cash from operating activities for Q4 2020 and YE 2020 was $39.5 million and $152.3 million, respectively, as compared to $52.0 million and $209.7 million for the comparable periods in 2019. Net cash from operating activities is generated from funds from operations and the net change in non-cash working capital. Funds from operations is utilized by management to evaluate the ability of the Company to generate cash from its 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 Q4 2020 and YE 2020 were $41.1 million and $146.8 million, respectively, a decrease of 26% from $55.8 million in Q4 2019 and a decrease of 33% from $220.4 million in YE 2019 primarily due to the significant decline in WTI benchmark pricing combined with lower oil production volumes due to lower overall exploration and development activity across Western Canada and shut-in production in response to the impacts of COVID-19 on global oil demand. This was partially offset by increased natural gas royalty revenue due to stronger AECO and Station 2 benchmark pricing.

	Three months ended December 31		Year ended December 31	
($ millions)	**2020**	**2019**	**2020**	**2019**
Funds from Operations	**$ 41.1**	$ 55.8	**$ 146.8**	$ 220.4
Funds from Operations as a % of Revenues	**87%**	83%	**86%**	82%

Investing Activities.

For Q4 2020 and YE 2020, cash used in investing activities was $1.9 million (Q4 2019 - $5.9 million) and $8.6 million (YE 2019 - $10.0 million), respectively, related primarily to royalty and E&E asset acquisitions as outlined in the "Acquisitions" section of this MD&A.

Financing Activities

For Q4 2020 and YE 2020, cash used in financing activities totaled $37.6 million (Q4 2019 - $46.1 million) and $143.7 million (YE 2019 - $199.7 million), respectively. Dividends paid in Q4 2020 were $13.4 million (Q4 2019 - $45.5 million) and $87.8 million for YE 2020 (YE 2019 - $182.2 million). No purchases were made under the NCIB in Q4 2020 (Q4 2019 - $2.8 million). During the year ended December 31, 2020, $90.9 million of NCIB purchases were made (YE 2019 - $19.0 million) as further described below. The share repurchases were funded with funds from operations in excess of the quarterly dividend, and by drawing down on the Company's available credit facility.

Since the initial public offering in May 2014 (the "IPO"), PrairieSky has declared $1,118.1 million in dividends to shareholders. Since inception of the NCIB in 2016, PrairieSky has purchased for cancellation 15.0 million common shares at an average cost of $14.90 per share for total consideration of $223.7 million.

Changes in Working Capital

The Company had a working capital deficiency of $42.0 million at December 31, 2020. The working capital deficiency has increased from $3.1 million at December 31, 2019 as the Company increased purchases under its NCIB by acquiring and cancelling $90.9 million in common shares during YE 2020. The share repurchases were funded with funds from operations in excess of the quarterly dividend, and by drawing down on the Company's available credit facility. At December 31, 2020, accounts receivable and accrued royalty revenue consisted primarily of accrued revenue related to royalty payments. In the crude oil and natural 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 share-based compensation and salary-related accruals. At December 31, 2020, income taxes payable totaled $1.5 million (December 31, 2019 - $4.7 million). The working capital deficiency included $2.6 million (December 31, 2019 - $2.7 million) related to the liability for vested cash-settled DSUs for Board members which may or may not be paid in the next twelve months as amounts only become payable when a director is no longer a member of the Board.

Bank Debt

At December 31, 2020, the Company had a $200 million extendible revolving credit facility (the "Revolving Facility"), with a permitted increase to $250 million, subject to lender consent, and a $25 million extendible operating credit facility (the "Operating Facility", and together with the Revolving Facility, the "Credit Facility"), with a syndicate of Canadian banks. As at December 31, 2020, the Company had $42.9 million in bank debt outstanding on the Credit Facility (December 31, 2019 - $7.3 million). The increase in bank debt was due to the Company's share repurchases under the NCIB which is further discussed below. The effective interest rate for Q4 2020 was 2.0% (Q4 2019 - 4.3%) and for YE 2020 was 2.2% (YE 2019 - 4.4%).

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 Credit Facility has three financial covenants, whereby the Company's ratio of adjusted consolidated senior debt to EBITDA for the 12 trailing months will not exceed 3.5:1.0, adjusted consolidated total debt to EBITDA for the 12 trailing months will not exceed 4.0:1.0, and the adjusted consolidated total debt to capitalization ratio will not exceed 55%. EBITDA used in the covenant calculation is net earnings adjusted for non-cash items, interest expense and income taxes. All covenants are calculated as at and for the 12 months ending December 31, 2020. As at December 31, 2020, the Company was compliant with all covenants provided for in the lending agreement.

The following table provides a listing of the key financial covenants as at December 31, 2020:

Covenant Description[1]	Ratio	December 31, 2020
Adjusted Consolidated Senior Debt to EBITDA	Maximum 3.5:1	0.3
Adjusted Consolidated Total Debt to EBITDA	Maximum 4.0:1	0.3
Adjusted Consolidated Total Debt to Capitalization	Maximum 55%	1.9%

(1) Capitalized terms are as defined in the Credit Facility agreement.

The covenants noted above are subject to specific definitions in the Credit Facility agreement.

On January 29, 2021, the Company renewed the Credit Facility, voluntarily reducing the Revolving Facility to $150 million, with a permitted increase to $200 million, subject to lender consent, while maintaining the Operating Facility at $25 million. The Revolving Facility and the Operating Facility are each for two-year terms maturing on January 30, 2023 and, subject to certain requirements, may be extendible annually. All financial covenants remain unchanged under the new Credit Facility.

Dividends and Dividend Policy

PrairieSky currently pays a quarterly dividend to shareholders at the discretion of the Board. Dividends declared were $13.4 million or $0.06 per share for Q4 2020 and $86.1 million or $0.3750 per share for YE 2020.

Due to the unprecedented global market volatility, on March 16, 2020, the Company announced the move to a quarterly dividend which commenced in Q2 2020 with the first quarterly dividend paid to holders of record on July 15, 2020. The dividend was adjusted to $0.24 per common share annually ($0.06 per common share quarterly) for the balance of 2020. On February 8, 2021, the Company announced that the Board has increased the dividend by 8% to $0.26 per common share on an annualized basis ($0.065 per common share on a quarterly basis).

The Board of Directors determines the dividend rate after considering expected commodity prices, foreign exchange rates, production volumes, economic conditions, 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, including commodity price volatility, over several months. It also recognizes the intention of maintaining a strong financial position to take advantage of business opportunities, including share repurchases and cancellations under the NCIB and acquisitions.

Outstanding Share Data

As at December 31, 2020, PrairieSky had 223.3 million common shares outstanding (December 31, 2019 - 233.1 million) and 1.6 million outstanding stock options (December 31, 2019 - 1.6 million) which have a weighted average exercise price of $22.62, well in excess of the current share price. Total outstanding units and options from all employee, officer, and director incentive plans is less than 1.0% of total common shares outstanding at December 31, 2020. As at February 8, 2021, there were 223.3 million common shares outstanding.

Capital Management

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 crude oil and natural gas development, which differentiates its cost structure from producers and 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 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 production 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; however, the preparation of financial forecasts is challenging in light of volatility in commodity prices and uncertainty regarding the timing for recovery in global crude oil demand. As a result, there may be adverse changes in cash flows, working capital or debt levels that are currently unforeseen.

On May 13, 2020 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 11,600,000 common shares over a twelve-month period which commenced on May 19, 2020 and expires no later than May 18, 2021. The actual number of common shares that may be purchased will be determined by the Company based on current and forecast funds from operations. 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. At December 31, 2020, 2.5 million common shares remained available for purchase and cancellation under the current NCIB.

During Q4 2020, the Company did not purchase shares under the NCIB (Q4 2019 - 200,000 common shares at a weighted average price of $14.03 per common share, including commissions, for total consideration of $2.8 million). In Q4 2019, 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 $0.1 million was charged to the deficit.

During YE 2020, the Company purchased for cancellation 9,770,691 common shares (YE 2019 - 1,083,920 common shares) at a weighted average price of $9.30 per common share (YE 2019 - $17.58 per common share), including commissions, for total consideration of $90.9 million (YE 2019 - $19.0 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 $0.2 million (YE 2019 - $3.8 million) was charged to the deficit.

Commitments

The Company has in place three royalty acquisition agreements with unrelated parties, all of which expire on or before December 31, 2021. At December 31, 2020, the total remaining commitment under these agreements was $8.3 million.

Subsequent Event

On February 5, 2021, the Company entered into a definitive agreement to acquire a royalty portfolio for cash consideration of $45.0 million, before adjustments, consisting of fee mineral title and royalty interest lands in Western Canada, and ownership of a seismic database complementary to the Company's existing Royalty Properties as well as the acquired assets.

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 its future royalty revenue 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. As a result of the COVID-19 global health crisis, crude oil demand has dropped sharply and the Company remains subject to increased commodity price risk. The Company does not hedge its commodity price risk.

Interest Rate Risk

The Company is exposed to interest rate risk on its credit facility. 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. Bank debt bears interest at a floating market rate with applicable variable margins.

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. During these unprecedented market challenges as a result of COVID-19, and the resulting decrease in global crude oil demand, collection of accounts receivable from third-party lessees remains a priority for the Company.

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 royalty contracts and other agreements with crude oil and natural 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, and has letters of credit in place with certain producers.

As at December 31, 2020, there were no counterparties 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 royalty revenue is the total carrying value.

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 these obligations. At December 31, 2020, the Company had a working capital deficiency of $42.0 million, an increase from $3.1 million at December 31, 2019. This increase is a result of the Company's decision to repurchase and cancel 9.8 million common shares for $90.9 million under the NCIB during YE 2020. The Company also has access to funding alternatives through its Credit Facility, which was renewed in January 2021 for a two-year term.

The Company’s royalty production volumes and resultant revenues with high operating netbacks provide significant liquidity. The primary uses of funds are administrative expenses, production and mineral taxes, finance expenses, income taxes, dividends, the repurchase and cancellation of PrairieSky's common shares, and acquisitions. The Company’s dividend, common share repurchases and capital acquisitions are discretionary. In light of the current volatility in commodity prices, along with the effect of COVID-19 on global crude oil demand, the preparation of financial forecasts is challenging. As a result, there may be adverse changes in cash flows, working capital or debt levels that are currently unforeseen.

The timing of expected cash outflows relating to bank debt of $42.9 million, accounts payable and accrued liabilities of $11.9 million, income taxes payable of $1.5 million, and the dividend payable of $13.4 million is less than one year. Included in accounts payable and accrued liabilities is $2.6 million related to vested cash-settled DSUs held by Board members which may or may not be paid in the next year as the amount only becomes payable when a director is no longer a member of the Board.

Operational and Business risks

PrairieSky has identified key operational and business risks that may impact financial results. The most significant of these risks are as follows:

- Volatility in commodity prices and quality differentials as a result of global and North American market forces and/or shifts in the balance between supply and demand for crude oil, NGL, and natural gas, including the impacts of COVID-19 on crude oil demand;
- The spread of the COVID-19 pandemic, including but not limited to the realized effects on the broader economy but also the potential, unrealized and unforeseeable impacts which are highly variable and cannot be predicted with a high degree of certainty;
- Access to transportation, including pipelines or other methods, for bringing crude oil and natural gas to market;
- Dependence on lessees and/or third-party operators to develop the Royalty Properties and the risks associated with exploration, development and production of crude oil and natural gas, including environmental risks and climate change, as further discussed below;
- Ability of participants in the crude oil and natural gas industry in Western Canada to access capital to develop the Royalty Properties and the industry as a whole;
- Third-party operator activity levels on the Royalty Properties and competition for land, goods and services, qualified personnel and capital funding;
- Variations in currency exchange rates;
- Imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves. The Company's reserves will deplete over time through continued production and our industry partners and royalty payors may not be able to replace the reserves on the Royalty Properties on an economic basis;
- Stock market volatility and the ability to access sufficient capital from internal and external sources;
- Third-party operational risks, including facility restrictions and weather, and/or marketing risks, including take-in-kind production volumes, resulting in delivery interruptions, delays, lower realized pricing and/or unanticipated production declines;
- Changes in government regulations, including mandated production curtailments, taxation, environmental and Crown royalty rates;
- Potential breakdown, invasion, virus, cyber-attack, security breach or destruction of information technology systems; and
- Variability of dividends based on PrairieSky’s financial performance and/or market conditions.

The Company employs the following strategies to mitigate these risks:

- Our Royalty Properties are diversified which limits the exposure to any one royalty payor, commodity, area, region or operator;
- We are a royalty interest holder and have no direct exposure to environmental claims and regulation or the associated costs;

- We are focused on controlling direct costs in order to maximize our funds from operations;
- Our royalty interest agreements and contracts provide mechanisms to ensure that our interests are protected;
- Systems and compliance processes are in place to identify and pursue any unpaid or incorrect revenues;
- Measures and processes, which include a recovery plan, are in place to reduce the risk of cyber-attacks to protect our information systems from being breached;
- We maintain a strong capital structure; and
- We maintain levels of liability insurance that meet or exceed industry standards.

Environmental Risks

The Canadian petroleum and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. These regulations are some of the most stringent and progressive in the world. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, including the abandonment and reclamation of well, facility and pipeline sites and the protection of water resources. Compliance with such regulations can require significant expenditures by the businesses operating on the Royalty Properties and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties. In addition, compliance with such regulations is required for a third-party to keep a lease on the Fee Lands in good standing. Failure to adhere to applicable regulations and contractual requirements can lead to a default and subsequent termination of a Fee Lands lease by PrairieSky. Further to these specific, known requirements, future changes to environmental legislation, including legislation for air pollution and greenhouse gas emissions, may impose further requirements on operators and other companies in the crude oil and natural gas industry. PrairieSky works with applicable federal, provincial and municipal regulators to ensure compliance.

Third-party operations and activities associated with the Royalty Properties emit greenhouse gases which may require parties leasing and/or operating the Royalty Properties to comply with federal and/or provincial greenhouse gas emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate measures that are ultimately put in place. Lessees and third-party operators of the Royalty Properties are responsible for the costs associated with environmental regulation and adherence to regulation. PrairieSky may be directly impacted by reduced industry activity or the inability to collect royalty payments. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on the Company's operations and financial condition. Additional specific risk factors related to the environment and climate change are included in PrairieSky's Annual Information Form and readers are encouraged to review such material, as well as PrairieSky's Responsibility Report which is located on our website at www.prairiesky.com.

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 8, 2021, 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

Management is required to make judgments, estimates, and assumptions through the application of the Company's accounting policies and practices, which have a significant impact on the financial results. A summary of PrairieSky's significant accounting policies can be found in Note 3 to the audited annual consolidated financial statements.

During the first quarter of 2020, the World Health Organization declared the novel coronavirus (COVID-19) outbreak a global pandemic prompting many countries around the world to close international borders, place restrictions on travel and force closures for certain types of public places and businesses that were deemed non-essential. These measures caused significant disruption to global economies, including reduced demand for commodities and volatile pricing. Although crude oil pricing has recovered from its lows in the second quarter of 2020, the potential direct and indirect impacts of the economic downturn and continued economic uncertainty have been considered in management's estimates, and assumptions at year end. The following discussion outlines the accounting policies and practices involving the use of judgments and estimates that are critical to determining PrairieSky's financial results.

Critical judgments are those judgments made by Management in the process of applying the Company's accounting policies and that have the most significant impact on the amounts recognized in the audited annual consolidated financial statements.

Significant estimates primarily relate to fair value estimates and unsettled transactions and events as at the date of the financial statements and accordingly, actual results could differ from these estimates.

Identification of CGUs

The identification of cash generating units ("CGUs") requires judgement. CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires judgment and interpretation. Factors considered in the classification include how management monitors the entity's operations, how management makes decisions about continuing or disposing of assets and operations, and the nature of the assets.

Business Combinations and Fair Value Measurements

Management's judgement is required to determine whether a transaction constitutes a business combination or asset acquisition based on the criteria in IFRS 3, "Business Combinations". Business combinations are accounted for using the acquisition method of accounting and are differentiated from an asset acquisition when business processes are associated with the assets.

The fair value of royalty assets and E&E assets recognized in a business combination and as determined for fair value less costs of disposal for impairment are based on market values. The market value of royalty assets is the estimated amount for which royalty assets could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and with compulsion. The market value of royalty assets are estimated with reference to the cash flow multiples from production of the same or similar assets, or are based on estimates of the discounted future cash flows from proved and probable reserves. The market value of E&E assets are estimated with reference to the market values of current arm's length transactions in comparable locations, or are based on estimates of the discounted future cash flows from undeveloped properties. The assumptions and estimates with respect to determining the fair value of royalty and E&E assets generally include estimates of discounted future cash flows from proved and probable crude oil and natural gas reserves, future benchmark commodity prices, and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net earnings can be affected by changes in future DD&A, asset impairment or goodwill impairment.

Reserve Estimates, Depletion and Impairments

Reserves estimates are not recorded in the Company's financial statements, but they do affect net earnings and assets and liabilities through their impact on depreciation, depletion and amortization ("DD&A"), amounts used for impairment calculations, deferred taxes and amounts used to determine fair values of assets acquired through acquisitions and business combinations. By their nature, proved and probable crude oil and natural gas reserves and the future cash flows derived from them are significant estimates, which are subject to measurement uncertainty, and include significant assumptions related to future royalty production from proved and probable crude oil and natural gas reserves and future realized commodity prices. Accordingly, the impact to amounts reported in the financial statements for future periods could be material. Reserves have been evaluated at December 31, 2020 by the Company's external independent qualified reserves evaluators.

Judgment is required to assess when impairment indicators, or reversal indicators, exist and impairment testing is required with respect to the carrying value of royalty assets and E&E assets. Estimation is required in determining internally developed cash flow estimates for undeveloped properties, including the timing of third-party development, as well as determining the discount rate.

The application of the Company's accounting policy to transfer assets from E&E assets to royalty assets or to expense capitalized E&E assets requires management to make certain judgments based on the estimated proved and probable crude oil and natural gas reserves, if any, used in the determination of an area's technical feasibility and commercial viability.

Goodwill

Upon acquisition, goodwill is attributed to the applicable CGU that is expected to benefit from the business combination's synergies. This represents the lowest level that goodwill is monitored for internal management purposes. Subsequent measurement of goodwill is at cost less any accumulated impairments.

Goodwill is assessed for impairment at least annually. Judgement is required to assess when indicators exist, and impairment testing is required more frequently. If the carrying amount for the CGU exceeds the recoverable amount of the CGU, the associated goodwill is written down with an impairment recognized in net earnings. The recoverable amounts are determined annually based on the greater of fair value less costs of disposal or value in use. Goodwill impairments are not reversed.

Crude Oil and Natural Gas Revenue Accruals

The Company follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of royalty revenue and related expenses, which are based on significant assumptions related to royalty production and realized commodity pricing, for the period reported, for which actual results have not yet been received. The Company has no operational control over the Royalty Properties and as a result, the Company uses both historical production information and publicly available production data adjusted pursuant to the terms of the Company's royalty agreements to determine royalty production. Realized commodity prices are based on publicly available benchmark commodity prices, adjusted for quality, location, allowable deductions, or other factors pursuant to the terms of the royalty agreements. These royalty revenue accrual estimates are revised based on actual royalty production volumes and realized commodity prices received in subsequent periods.

Share-Based Compensation

The calculation of share-based compensation includes both judgments and estimates. Judgments include which valuation model is most appropriate to estimate the fair value of awards granted under the Company's Stock Option Plan, as well as the determination of the peer group used to calculate the total shareholder return under the PSU Plan. An estimate is made for certain PSU grants that are subject to a multiple performance criteria methodology at the discretion of the Board of Directors. Based on this assessment, a range of zero to two times the original PSU grant may be eligible to vest in respect of the three-year trailing period being measured.

Under the Stock Option Plan, the Company uses the Black-Scholes option pricing model which requires that management make estimates for the expected life of the option, the anticipated volatility of the share price over the life of the option, the dividend yield, the risk-free interest rate for the life of the option, and the number of options that will ultimately vest. Estimates of forfeiture rates are made through the vesting period for the Company’s various long-term incentive plans. Estimates are based on past forfeitures and future expectations and are adjusted for actual forfeitures when stock options or share unit awards are exercised and/or vested. Estimates and assumptions are then used in the valuation model to determine the fair value, including the number of share unit awards that will ultimately vest under the Share Unit Award Incentive Plan for PSUs and RSUs and under the ODSU Plan. Fluctuations in share-based compensation may occur due to changes in the underlying share price, forfeitures or revised management estimates of relevant performance factors for PSUs. Estimates of the total shareholder return for PSUs are made at each period end.

Income Taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in the period of change and future periods. In periods of rate change, the Company estimates the timing of anticipated reversal of the associated deferred income tax liability to determine the appropriate tax rate to apply to temporary differences. Deferred income tax assets are recognized to the extent future recovery is probable in management’s judgment. Deferred income tax assets are reduced to the extent that it is no longer probable that sufficient taxable earnings will be available to allow all or part of the asset to be recovered.

Accounting Policy Changes

IFRS 3

On January 1, 2020, the Company adopted the amendments to the definition of a business in IFRS 3 Business Combinations. The amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. IFRS 3 continues to adopt a market participant’s perspective to determine whether an acquired set of activities and assets is a business. The amendments clarify the minimum requirements for a business, remove the assessment of whether market participants are capable of replacing any missing elements, add guidance to help entities assess whether an acquired process is substantive, narrow the definitions of a business and of outputs, and introduce an optional fair value concentration test. No business combinations were completed during the year ended December 31, 2020.

Control Environment

The Board, through its Audit Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit Committee meets at least quarterly with the Company’s external auditors to review accounting, internal control, financial reporting, and audit matters.

Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P"), as defined by National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings ("NI 52-109"), are designed to provide reasonable assurance that information required to be disclosed in the Company’s annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and the Chief Financial Officer evaluated the design and operating effectiveness of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's DC&P were designed and operating effectively as at December 31, 2020.

Internal Controls over Financial Reporting

Internal controls over financial reporting ("ICFR") is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. Because of its inherent limitations, ICFR can only provide reasonable, not absolute, assurance that the objective of the control system is met. There were no changes to PrairieSky's ICFR during the period beginning on October 1, 2020 to December 31, 2020 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR. PrairieSky conducted an evaluation of the design and operating effectiveness of the Company's ICFR as at December 31, 2020 based on the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that as of December 31, 2020, PrairieSky maintained effective ICFR as defined in Canada by NI 52-109.

Selected Annual Information

(millions, except per share)	**2020**	2019	2018
Revenues	**$ 171.4**	$ 268.4	$ 273.8
Net Earnings and Comprehensive Income	**31.7**	111.4	79.4
Per Share – basic and diluted	**0.14**	0.48	0.34
Total Assets	**2,607.7**	2,719.5	2,816.9
Long-term Liabilities	**196.5**	192.8	212.3
Dividends Declared	**86.1**	182.1	182.1
Per Share	**0.3750**	0.7800	0.7750

In the past three years, PrairieSky has operated its business by leasing lands to third-parties for crude oil and natural gas development and third-party operations, managing controllable costs and completing accretive acquisitions which are complementary to PrairieSky's business. Over the three years, fluctuations in realized commodity prices due to changing benchmark prices and widening/narrowing differentials have impacted the crude oil and natural gas industry and the Company's royalty production revenue. During 2020, the impacts of COVID-19 and the reduction in global oil demand resulted in significantly lower benchmark and realized crude oil pricing. Net earnings have fluctuated primarily due to the changes in revenues as discussed above, as well as the $25.5 million deferred income tax recovery in 2019 due to the corporate income tax rate reductions enacted by the Alberta provincial government. Long-term liabilities include deferred income tax of $193.0 million in 2020 (2019 - $189.6 million, 2018 - $211.2 million). Dividends per share are reviewed and set on an annual basis by the Board. The annual dividend was adjusted to $0.24 per common share, with $0.06 per common share approved and paid on a quarterly basis, commencing in Q2 2020.

Summary of Quarterly Results and Trends

($ millions, unless otherwise noted)	Q1 2019	Q2 2019	Q3 2019	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
FINANCIAL								
Crude Oil	$ 46.3	$ 52.1	$ 43.4	$ 46.9	$ 33.0	$ 13.4	$ 24.8	**$ 28.0**
NGL	9.1	6.5	4.4	6.7	7.0	4.1	4.9	**5.6**
Natural Gas	11.1	4.5	4.1	9.8	9.1	7.6	8.7	**10.0**
Royalty Production Revenue	$ 66.5	$ 63.1	$ 51.9	$ 63.4	$ 49.1	$ 25.1	$ 38.4	**$ 43.6**
Other Revenue	6.7	6.2	6.9	3.7	3.6	3.1	5.1	**3.4**
Total Revenue	73.2	69.3	58.8	67.1	52.7	28.2	43.5	**47.0**
Funds from Operations	57.8	58.0	48.8	55.8	46.5	21.3	37.9	**41.1**
Per Share - basic(1)	0.25	0.25	0.21	0.24	0.20	0.09	0.16	**0.18**
Per Share - diluted(1)	0.25	0.24	0.21	0.24	0.20	0.09	0.16	**0.18**
Net Earnings (Loss)	26.4	44.0	16.7	24.3	8.6	(0.4)	9.4	**14.1**
Per Share - basic and diluted(1)	0.11	0.19	0.07	0.10	0.04	(0.00)	0.04	**0.06**
Dividends Declared(2)	45.6	45.6	45.5	45.4	45.4	13.9	13.4	**13.4**
Per Share	0.1950	0.1950	0.1950	0.1950	0.1950	0.0600	0.0600	**0.0600**
Working Capital (Deficiency)	(6.2)	(2.1)	(7.4)	(3.1)	(5.2)	(8.7)	(66.2)	**(42.0)**
OPERATIONAL								
Production Volumes								
Crude Oil (bbls/d)	8,904	8,740	8,011	8,884	8,582	6,035	6,572	**7,313**
NGL (bbls/d)	2,586	2,690	2,334	2,819	2,945	2,586	2,473	**2,285**
Natural Gas (MMcf/d)	63.1	65.2	61.0	63.0	63.8	60.3	58.2	**58.1**
Total (BOE/d)(3)	22,007	22,297	20,512	22,203	22,160	18,671	18,745	**19,281**

(1) Net Earnings and Funds from Operations per Share are calculated using the weighted average number of basic and diluted common shares outstanding.
(2) A dividend of $0.06 per common share was declared on December 7, 2020. The dividend was paid on January 15, 2021 to shareholders of record on December 31, 2020.
(3) See "Conversions of Natural Gas to BOE".

- Quarterly variances in revenues, funds from operations and net earnings are primarily due to fluctuations in realized commodity prices, royalty production volumes, and bonus consideration.

- Crude oil prices are generally determined by global and North American market forces, including supply and demand factors. Changes in the USD-CAD currency exchange rate impact the Company's oil price realization relative to benchmark WTI, which is referenced in US dollars. In Q1 2020, realized commodity prices were negatively impacted by wider differentials for Canadian light and heavy crude oil to WTI due to global crude oil demand and supply imbalances primarily as a result of COVID-19. Differentials narrowed subsequent to Q1 2020 but did not offset the significant decline in WTI benchmark pricing.

- Natural gas prices are influenced by many variables including weather conditions, industrial demand, and North American natural gas inventories. In Western Canada, transportation constraints further impact natural gas prices.

- Royalty 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, the expertise and financial resources of third-party lessees, acquisitions of producing properties and natural declines.

- Other revenue is largely affected by the timing of bonus consideration received when new leases are negotiated, which can vary with the individual terms of each agreement.

- Net earnings are affected by revenues, as noted above, as well as depletion, administrative expenses and income taxes. Administrative expenses can vary in a period due to the effect of the change in share price on the Company's share-based compensation plans. The Alberta corporate income tax rate was reduced for the periods from July 1, 2019 to 2022, bringing the provincial income tax rate from 12% to 11% effective July 1, 2019 and further reducing the rate by 1% effective January 1, 2020 with additional 1% reductions commencing January 1, 2021, and 2022. The initial deferred tax recovery related to the tax rate reductions was recorded in Q2 2019. In October 2020, the Alberta government accelerated the corporate income tax rate reduction to 8% effective July 1, 2020.

- Dividends decline marginally as the number of shares outstanding in the quarter is reduced by share repurchases and cancellations under the NCIB. The dividend is set by the Board of Directors by considering forecasted funds from operations for the next year. Due to global market volatility as a result of COVID-19, the dividend was adjusted to a quarterly dividend commencing in Q2 2020 of $0.06 per common share.

- The Company has declared $268.2 million in dividends to shareholders and has repurchased 10.9 million common shares for $109.9 million over the past eight quarters.

- The working capital deficiency increased in Q3 2020 as a result of the significant increase in the number of shares repurchased and cancelled under the NCIB. In prior quarters, the working capital deficiency fluctuated primarily as a result of changes in commodity prices affecting the accrued royalty revenue receivable recorded.

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 crude oil and natural 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, operating margin, cash administrative expenses and cash administrative expenses per BOE. 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 revenue less production and mineral taxes and cash administrative expenses. Operating netback provides a consistent measure of the cash generating and operating 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 average daily production volumes for the period. Operating netback per BOE is used to assess the cash generating and operating performance per unit of product sold. Operating netback per BOE measures are commonly used in the crude oil and natural 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.

"Operating Margin" represents operating netback as a percentage of royalty revenue. Management uses this measure to demonstrate the comparability between the Company and production and exploration companies in the crude oil and natural gas industry as it shows net revenue generation from operations.

"Cash Administrative Expenses" represents administrative expenses excluding the volatility and fluctuations in share-based compensation expense for RSUs, PSUs, ODSUs and DSUs and stock options that were not settled in cash in the current period. Cash administrative expenses are calculated as total administrative expenses, adjusting for share-based compensation expense (recovery) in the period, plus any actual cash payments made under the Share Unit Award Incentive Plan, ODSU Plan or DSU Plan. Management believes cash administrative expense is a common benchmark used by investors when comparing companies to evaluate operating performance.

"Cash Administrative Expenses per BOE" represents cash administrative expenses on a BOE basis. Cash administrative expenses per BOE is calculated by dividing cash administrative expenses by the average daily production volumes for the period. Cash administrative expenses per BOE assists management and investors in evaluating operating performance on a comparable basis between periods.

Cash Administrative Expenses

The following table presents the computation of Cash Administrative Expenses:

($ millions)	Three months ended December 31 2020	Three months ended December 31 2019	Year ended December 31 2020	Year ended December 31 2019
Total Administrative Expenses	**$ 4.9**	$ 3.1	**$ 18.6**	$ 23.7
Share-Based Compensation Recovery (Expense)	**(1.4)**	1.0	**(2.3)**	(4.6)
Cash Payments Made - Share Unit Award Incentive Plan	**-**	-	**1.7**	2.2
Cash Administrative Expenses	**$ 3.5**	$ 4.1	**$ 18.0**	$ 21.3

Advisory

FORWARD-LOOKING STATEMENTS

This MD&A includes certain statements regarding PrairieSky's future plans and operations as at February 8, 2021 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, and specifically the effect of the COVID-19 pandemic on future royalty production volumes, revenues and cash flow;
- The potential magnitude of impacts from the COVID-19 pandemic, including the fact that many potential factors are unforeseeable and cannot be predicted or quantified with any degree of certainty;
- 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 and share repurchases and cancellations over time, which intention could change with little or no notice;
- PrairieSky's NCIB and specifically the volume and value of future repurchases under the NCIB based on current and forecast funds from operations;
- 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;
- the Company's estimates of production shut-in across the Royalty Properties, and the impacts thereof, as well as the timing for third-party operators to bring these volumes back on production;
- the estimated impact of shut-in oil volumes on associated solution gas, and the possibility of these gas volumes returning;

- the Company's estimate regarding third-party operators' approach to budgets and capital spending;
- the ability to mitigate the risks of fluctuations in commodity prices and production volumes, including but not limited to impacts from a slowdown in exploration and development activity; and
- average production contributions from the Royalty Properties including the impact of declines;
- impact of PrairieSky's share price on administrative expenses;
- the expectation that there will be no operating costs, capital costs, environmental liabilities, or abandonment and reclamation obligations associated with the development of the Royalty Properties;
- expected future commitments and payments related thereto; and
- changes to the legislative and regulatory frameworks, including changes to environmental legislation, in the jurisdictions in which the Company carries on a business.

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, the trajectory of the global COVID-19 pandemic, volatility of commodity prices, lack of pipeline capacity, currency fluctuations, imprecision of reserve estimates, royalties, environmental risks, 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 third-party operators on the Royalty Properties 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 Royalty Properties; the level of costs and expenses to be incurred by PrairieSky, including with respect to interest, production and mineral taxes, 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; the effects of COVID-19 on global crude oil demand and pricing as well as local and global social and economic conditions; and PrairieSky's ability to execute the volume and/or value of purchases as described under the NCIB or future NCIBs.

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 audited annual 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 2020 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.