Exhibit 99.1

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of financial results is dated May 6, 2021 and is to be read in conjunction with:

- the unaudited interim condensed consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three months ended March 31, 2021 and 2020 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2020 and 2019 and for the years ended December 31, 2020, 2019 and 2018; and
- our MD&A for the year ended December 31, 2020 (the "Annual MD&A").

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" at the end of the MD&A for further information. In addition, the following MD&A contains disclosure regarding certain risks and uncertainties associated with Enerplus' business. See "Risk Factors and Risk Management" in the Annual MD&A and "Risk Factors" in Enerplus' annual information form for the year ended December 31, 2020 (the "Annual Information Form").

BASIS OF PRESENTATION

The Interim Financial Statements and Notes thereto have been prepared in accordance with U.S. GAAP, including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included in the Interim Financial Statements. Certain prior period amounts have been reclassified to conform with current period presentation.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 bbl and crude oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcf. BOE and Mcfe measures are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1 or 0.167:1, as applicable, utilizing a conversion on this basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. Unless otherwise stated, all production volumes and realized product prices information is presented on a "Company interest" basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and may not be comparable to information produced by other entities.

All references to "liquids" in this MD&A include light and medium crude oil, heavy oil and tight oil (all together referred to as "crude oil") and natural gas liquids on a combined basis. All references to "natural gas" in this MD&A include conventional natural gas and shale gas.

In accordance with U.S. GAAP, crude oil and natural gas sales are presented net of royalties in our Interim Financial Statements. Under International Financial Reporting Standards, industry standard is to present crude oil and natural gas sales before deduction of royalties, and as such, this MD&A presents production, crude oil and natural gas sales, and BOE measures on this basis to remain comparable with our Canadian peers.

Unless otherwise expressly stated, information presented in this MD&A does not give effect to the acquisition (the "Hess Acquisition") by Enerplus Resources (USA) Corporation, an indirect wholly-owned subsidiary of the Company, of certain assets in the Williston Basin from Hess Bakken Investments II, LLC ("Hess"), as announced on April 8, 2021. The Hess Acquisition closed on April 30, 2021. See the material change report dated April 16, 2021 in connection with the Hess Acquisition available under Enerplus' SEDAR profile at www.sedar.com and on Enerplus' EDGAR profile under Form 6-K at www.sec.gov.

For more details on our acquisition (the "Bruin Acquisition") of Bruin E&P HoldCo, LLC ("Bruin"), see Note 4 to the Interim Financial Statements as well as the material change report dated January 29, 2021 and the business acquisition report dated April 13, 2021, each available under Enerplus' SEDAR profile at www.sedar.com and Enerplus' EDGAR profile under Form 6-K at www.sec.gov.

OVERVIEW

During the first quarter of 2021, global economies began to recover from the impacts brought on by the coronavirus ("COVID-19") pandemic. Demand for crude oil improved and prices returned to pre-COVID-19 levels, bringing some stability to our industry.

On January 25, 2021, we entered into a purchase and sale agreement to acquire all of the outstanding equity interests of Bruin a private company that holds oil and gas interests in certain properties located in the Williston Basin in North Dakota. The Bruin Acquisition was completed on March 10, 2021 and the cash purchase price of approximately US$465 million, prior to the preliminary purchase price adjustments of US$47 million, was funded by a new three-year US$400 million term loan and through a portion of the proceeds of a bought deal public offering of common shares, which was completed on February 3, 2021. Bruin's assets were producing approximately 24,000 BOE/day (72% tight oil, 14% natural gas liquids, and 14% natural gas) upon completion of the transaction.

On April 8, 2021, we announced that we had entered into a purchase and sale agreement to acquire certain assets in the Williston Basin from Hess for total cash consideration of US$312 million, subject to customary purchase price adjustments. The Hess Acquisition closed on April 30, 2021 and was funded using our existing cash balance and drawing on our bank credit facility. The Hess assets have production of approximately 6,000 BOE/day (76% tight oil, 10% natural gas liquids, and 14% natural gas). We expect the Bruin Acquisition and Hess Acquisition to contribute meaningful free cash flow and provide additional core inventory while increasing the scope and scale of our business.

Production during the first quarter of 2021 averaged 91,671 BOE/day, a 6% increase compared to production of 86,244 BOE/day in the fourth quarter of 2020. The increased production was driven by strong well performance in North Dakota and the Marcellus. Bruin's assets, which were acquired on March 10, 2021, contributed 6,300 BOE/day of production in the first quarter of 2021. This increase was offset by natural production declines in our portfolio as capital spending on our 2021 program began in February and we had limited capital spending throughout 2020. Our 2021 production volumes are expected to average 111,000 to 115,000 BOE/day including 68,500 to 71,500 bbls/day of liquids production with an eight month contribution from the Hess Acquisition in 2021.

Capital spending during the first quarter of 2021 totaled $65.5 million, compared to $52.4 million during the fourth quarter of 2020. The majority of the spending was focused on our U.S. crude oil properties, as we initiated our completion program in North Dakota resulting in a total of 5.6 net operated wells and 0.7 non-operated wells coming on-stream late in the quarter. We expect capital spending for 2021 of between $360 to $400 million.

Our realized Bakken crude oil price differential narrowed to average US$3.12/bbl below WTI during the first quarter of 2021 compared to US$4.82/bbl below WTI during the fourth quarter of 2020. Bakken differentials in North Dakota were supported by increased refinery demand, while production remained stable. We expect our annual Bakken crude oil price differential to average US$3.25/bbl below WTI for 2021, assuming the continued operation of the Dakota Access Pipeline ("DAPL").

Our realized Marcellus natural gas price differential averaged US$0.15/Mcf below NYMEX in the first quarter of 2021, compared to US$1.07/Mcf below NYMEX during the fourth quarter of 2020, as demand increased with the colder winter weather in the first quarter. We expect our annual Marcellus natural gas price differential to average US$0.55/Mcf below NYMEX.

Operating costs for the first quarter of 2021 were in line with the fourth quarter of 2020 and decreased on a per BOE basis to $64.5 million or $7.82/BOE, compared to $65.1 million or $8.20/BOE respectively, due to higher natural gas production in the Marcellus. We expect operating expenses to average $8.25/BOE, during 2021.

We reported net income of $14.7 million in the first quarter of 2021 compared to a net loss of $204.2 million in the fourth quarter of 2020. The net income recognized in the first quarter of 2021 was primarily due to higher production and commodity prices along with a significantly lower non-cash property, plant and equipment ("PP&E") impairment of $4.3 million compared to the fourth quarter of 2020, where we recorded a $311.2 million non-cash PP&E impairment.

Cash flow from operations decreased to $37.2 million in the first quarter of 2021 compared to $96.1 million in the fourth quarter of 2020 primarily due to changes in working capital. Higher accrued revenue receivables at March 31, 2021 was a result of higher commodity prices and higher production during the first quarter of 2021, compared to December 31, 2020. First quarter adjusted funds flow increased to $128.0 million from $91.9 million over the same period. The increase was primarily due to higher production and an improvement in commodity prices during the quarter.

At March 31, 2021, our total debt net of cash was $794.2 million, compromised of senior notes and term loan totaling $983.2 million, less cash on hand of $189.0 million. Our net debt to adjusted funds flow ratio was 2.1x, which does not include the trailing adjusted funds flow associated with the Bruin Acquisition. At March 31, 2021 and as of the date of this MD&A, we are in compliance with all debt covenants.

Subsequent to the quarter end, we increased and extended our senior unsecured bank credit facility to US$900 million from US$600 million with a maturity of October 31, 2025. In addition, we transitioned the facility to a sustainability linked credit facility with three sustainability-linked performance targets, which reduce or increase our borrowing costs by up to 5 bps as the targets are exceeded or missed.

On May 6, 2021, the Board of Directors approved a 10% increase to the dividend to $0.033 per share paid quarterly, from $0.01 per share paid monthly previously. The increased quarterly dividend is payable on June 15, 2021 to all shareholders of record at the close of business on May 28, 2021. Given the April and May dividends have already been paid or declared, the change to quarterly payments beginning in June represents an incremental dividend payment of $5.6 million in the second quarter of 2021. This change is consistent with our commitment to sustainably grow our return of capital to shareholders

RESULTS OF OPERATIONS

Production

Daily production for the first quarter of 2021 averaged 91,671 BOE/day, an increase of 6% compared to average production of 86,244 BOE/day in the fourth quarter of 2020. Bruin's assets, which were acquired on March 10, 2021, contributed 6,300 BOE/day of production in the first quarter of 2021. Despite the contribution from Bruin, crude oil and natural gas liquids production was consistent with the fourth quarter of 2020 due to natural production declines in our portfolio as capital spending on our 2021 program began in February and we had limited capital spending throughout 2020. Natural gas production increased 8% to 255,749 Mcf/day in the first quarter of 2021 from 237,857 Mcf/day in the fourth quarter of 2020 due to increased on-stream activity in the Marcellus.

For the three months ended March 31, 2021, total production decreased by 7% when compared to the same period in 2020. The decrease in production was primarily due to the suspension of all operated drilling and completion activity in North Dakota during the second quarter of 2020 in response to the significant decline in crude oil prices. Our Marcellus natural gas production decreased by 6% due to limited capital activity in 2020. These impacts were partially offset by an increase in natural gas liquids production over the same period in part due to an increase in natural gas liquids recoveries.

Our crude oil and natural gas liquids weighting decreased to 54% in the first quarter of 2021 from 55% in the same period of 2020.

Average daily production volumes for the three months ended March 31, 2021 and 2020 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2021**	**2020**	**% Change**
Tight oil (bbls/day)	35,275	41,208	(14)%
Heavy oil (bbls/day)	4,118	4,356	(5)%
Light and medium oil (bbls/day)	3,072	3,480	(12)%
Total crude oil (bbls/day)	42,465	49,044	(13)%
Natural gas liquids (bbls/day)	6,581	5,346	23%
Shale gas (Mcf/day)	246,191	248,263	(1)%
Conventional natural gas (Mcf/day)	9,558	14,650	(35)%
Total natural gas (Mcf/day)	255,749	262,913	(3)%
Total daily sales (BOE/day)	91,671	98,209	(7)%

We expect annual average production for 2021 of 111,000 – 115,000 BOE/day, including 68,500 – 71,500 bbls/day in crude oil and natural gas liquids production, with a ten month contribution from the Bruin Acquisition and an eight month contribution from the Hess Acquisition in 2021.

Pricing

The prices received for crude oil and natural gas production directly impact our earnings, cash flow from operations, adjusted funds flow and financial condition. The following table compares quarterly average selling prices, benchmark prices and differentials:

Pricing (average for the period)	**Q1 2021**	**Q4 2020**	**Q3 2020**	**Q2 2020**	**Q1 2020**
Benchmarks					
WTI crude oil (US$/bbl)	$ 57.84	$ 42.66	$ 40.93	$ 27.85	$ 46.17
Brent (ICE) crude oil (US$/bbl)	61.10	45.24	43.37	33.27	50.96
NYMEX natural gas – last day (US$/Mcf)	2.69	2.66	1.98	1.72	1.95
USD/CDN average exchange rate	1.27	1.30	1.33	1.39	1.34
USD/CDN period end exchange rate	1.26	1.27	1.33	1.36	1.41
Enerplus selling price[1]					
Crude oil ($/bbl)	$ 67.34	$ 47.95	$ 46.43	$ 30.55	$ 51.30
Natural gas liquids ($/bbl)	36.17	17.19	10.60	(0.96)	12.72
Natural gas ($/Mcf)	3.48	2.04	1.72	1.63	2.08
Average differentials					
Bakken DAPL – WTI (US$/bbl)	$ (2.63)	$ (3.45)	$ (3.40)	$ (5.24)	$ (5.34)
Brent (ICE) – WTI (US$/bbl)	3.26	2.58	2.44	5.42	4.79
MSW Edmonton – WTI (US$/bbl)	(5.24)	(3.91)	(3.51)	(6.14)	(7.58)
WCS Hardisty – WTI (US$/bbl)	(12.47)	(9.30)	(9.08)	(11.47)	(20.53)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.19)	(1.18)	(0.80)	(0.45)	(0.39)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	0.61	(0.85)	(0.56)	(0.37)	0.41
Enerplus realized differentials[1][2]					
Bakken crude oil – WTI (US$/bbl)	$ (3.12)	$ (4.82)	$ (5.37)	$ (4.36)	$ (5.26)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.15)	(1.07)	(0.72)	(0.49)	(0.38)
Canada crude oil – WTI (US$/bbl)	(12.89)	(10.18)	(9.74)	(14.49)	(17.77)

(1) Excluding transportation costs, royalties and the effects of commodity derivative instruments.
(2) Based on a weighted average differential for the period.

CRUDE OIL AND NATURAL GAS LIQUIDS

During the first quarter of 2021, our realized crude oil sales price averaged $67.34/bbl, an increase of 40% compared to the fourth quarter of 2020 and consistent with the increase in the benchmark WTI price over the same period. In the U.S., crude oil prices and price differentials strengthened as refinery demand increased due to improving market demand and the gradual easing of COVID-19 restrictions. Oil supply continues to be managed through ongoing extensions of the agreement made by the Organization of the Petroleum Exporting Countries Plus (“OPEC+”) nations to curtail production from the market through mid-2022.

Our realized Bakken crude oil price differential averaged US$3.12/bbl below WTI during the first quarter of 2021 compared to US$4.82/bbl below WTI during the fourth quarter of 2020. Bakken differentials in North Dakota were supported by increased refinery demand specifically in the U.S. Midwest due to a record cold weather event in February, which significantly disrupted U.S. Gulf Coast refining activity. Additionally, regional production remains lower than pre-pandemic levels.

Our Bakken crude oil sales portfolio consists of a combination of in-basin monthly spot and index sales, term physical sales with fixed differential pricing versus WTI, sales at Cushing, and sales at the U.S. Gulf Coast delivered via firm capacity on DAPL. DAPL continues to operate despite ongoing legal challenges and further environmental review. Assuming the ongoing operation of DAPL, we expect our annual Bakken realized crude oil sales price differential to average approximately US$3.25/bbl below WTI in 2021.

Our realized Canadian crude oil price differential widened by US$2.71/bbl compared to the fourth quarter of 2020, which was in line with changes to the underlying benchmark prices.

Our realized sales price for natural gas liquids averaged $36.17/bbl during the first quarter of 2021, compared to $17.19/bbl in the fourth quarter of 2020. Natural gas liquids prices benefited substantially from the cold weather event in February which was centered over key natural gas liquids pricing hubs in both the Midwest and Texas.

NATURAL GAS

Our realized natural gas sales price averaged $3.48/Mcf during the first quarter of 2021, an increase of 70% compared to the fourth quarter of 2020. NYMEX benchmark prices increased by 1% over the same period as winter weather remained fairly neutral until late February when severe cold weather caused prices to increase significantly across many areas of the U.S.

Regional pricing in the Marcellus was much stronger during the first quarter of 2021, compared to the previous quarter, due to an increase in seasonal demand with the onset of colder winter weather. As a result, our realized Marcellus sales price differential narrowed to average US$0.15/Mcf below NYMEX during the quarter compared to US$1.07/Mcf below NYMEX in the fourth quarter of 2020. This narrowing was in line with the changes in the underlying benchmark basis pricing and significant seasonality in pricing we expect in the U.S. Northeast during the winter. We expect our Marcellus differential to average US$0.55/Mcf below NYMEX for the full year.

FOREIGN EXCHANGE

Our crude oil and natural gas sales are impacted by foreign exchange fluctuations as the majority of our sales are based on U.S. dollar denominated benchmark indices. A stronger Canadian dollar decreases the amount of our realized sales as well as the amount of our U.S. denominated costs, such as capital, the interest on our U.S. denominated debt, and the value of our outstanding U.S. senior notes and term loan.

The Canadian dollar continued to strengthen during the first quarter of 2021 in response to higher commodity prices as global economies stabilized and crude oil demand continued to recover from the onset of the COVID-19 pandemic in the first quarter of 2020. The Canadian dollar ended the first quarter at 1.26 USD/CAD, compared to 1.27 USD/CAD at December 31, 2020. The average exchange rate of 1.27 USD/CAD during the first quarter of 2021 was considerably stronger than the same period in 2020 when it averaged 1.34 USD/CAD.

Price Risk Management

We have a price risk management program that considers our overall financial position, free cash flow and the economics of our capital program.

We continue to expect our hedging contracts to protect a portion of our cash flow from operating activities and adjusted funds flow. As of May 5, 2021, we have hedged 30,900 bbls/day of crude oil for the remainder of 2021 and 20,800 bbls/day during 2022. We have also hedged 100,000 Mcf/day of natural gas for the period of April 1, 2021 to October 31, 2021. Our crude oil hedges consist of swaps and three way collars. The three way collars provide us with exposure to significant upward price movement; however, the sold put effectively limits the amount of downside protection we have to the difference between the strike price of the purchased and sold puts.

The following is a summary of our financial contracts in place at May 5, 2021:

	WTI Crude Oil (1)(2) (US$/bbl)					NYMEX Natural Gas (US$/Mcf)
	Apr 1, 2021 – Jun 30, 2021	**Jul 1, 2021 – Dec 31, 2021**	**Jan 1, 2022 – Dec 31, 2022**	**Jan 1, 2023 – Oct 31, 2023**	**Nov 1, 2023 – Dec 31, 2023**	**Apr 1, 2021 – Oct 31, 2021**
Swaps						
Volume (bbls/day)	–	–	–	–	–	60,000
Sold Swaps	–	–	–	–	–	$ 2.90
Three Way Collars						
Volume (bbls/day)	20,000	23,000	17,000	–	–	40,000
Sold Puts	$ 32.00	$ 36.39	$ 40.00	–	–	$ 2.15
Purchased Puts	$ 40.90	$ 46.39	$ 50.00	–	–	$ 2.75
Sold Calls	$ 50.72	$ 56.70	$ 57.91	–	–	$ 3.25
Hedges acquired from Bruin(3)						
Swaps						
Volume (bbls/day)	9,750	8,465	3,828	250	–	–
Sold Swaps	$ 42.16	$ 42.52	$ 42.35	$ 42.10	–	–
Collars						
Volume (bbls/day)	–	–	–	2,000	2,000	–
Purchased Puts	–	–	–	$ 5.00	$ 5.00	–
Sold Calls	–	–	–	$ 75.00	$ 75.00	–

(1) The total average deferred premium spent on our outstanding hedges is US$0.67/bbl from April 1, 2021 - December 31, 2021 and US$1.22/bbl from January 1, 2022 - December 31, 2022.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Upon closing of the Bruin Acquisition, Bruin's outstanding hedges were recorded at a fair of $96.5 million value on the Condensed Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired hedges are recognized in Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the date of closing of the Bruin Acquisition. See Note 17 to the Interim Financial Statements for further details.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	Three months ended March 31,	
($ millions)	**2021**	**2020**
Cash gains/(losses):		
Crude oil	$ (20.1)	$ 33.0
Natural gas	0.7	—
Total cash gains/(losses)	$ (19.4)	$ 33.0
Non-cash gains/(losses):		
Crude oil	$ (51.7)	$ 98.3
Natural gas	1.3	—
Total non-cash gains/(losses)	$ (50.4)	$ 98.3
Total gains/(losses)	$ (69.8)	$ 131.3

	Three months ended March 31,	
(Per BOE)	**2021**	**2020**
Total cash gains/(losses)	$ (2.35)	$ 3.69
Total non-cash gains/(losses)	(6.11)	11.01
Total gains/(losses)	$ (8.46)	$ 14.70

We realized cash losses of $20.1 million on our crude oil contracts during the first quarter of 2021, compared to realized cash gains of $33.0 million for the same period in 2020. We recorded realized cash gains of $0.7 million on our natural gas contracts in the first quarter of 2021 and there were no natural gas derivative contracts outstanding during the first quarter of 2020.

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At March 31, 2021, the fair value of our crude oil and natural gas contracts was in a net liability position of $150.9 million. For the three months ended March 31, 2021, the change in the fair value of our crude oil contracts resulted in an unrealized loss of $51.7 million compared to a gain of $98.3 million during the same period in 2020. We recorded an unrealized gain of $1.3 million during the first quarter of 2021 on our natural gas contracts.

On March 10, 2021, the outstanding crude oil hedges acquired with the Bruin Acquisition were recorded at fair value, resulting in a liability of $96.5 million on the Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired hedges are recognized in Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the closing date of the Bruin Acquisition. For the three months ended March 31, 2021 we recorded a realized gain of $0.5 million on the first settlement of the Bruin hedges. We recognized an unrealized gain of $17.4 million in the Consolidated Statement of Income/(Loss) for the change in the fair value of the Bruin hedges during the first quarter of 2021. At March 31, 2021, the fair value of the Bruin hedges was a liability of $70.9 million. See Note 17 to the Interim Financial Statements for further detail.

Revenues

($ millions)	Three months ended March 31, 2021	2020
Crude oil and natural gas sales	$ 359.3	$ 285.6
Royalties	(70.5)	(57.5)
Crude oil and natural gas sales, net of royalties	$ 288.8	$ 228.1

Crude oil and natural gas sales, net of royalties, for the three months ended March 31, 2021 were $288.8 million, an increase of 27% from the same period in 2020. The increase in revenue was primarily due to higher realized prices, partially offset by lower production compared to the same period in 2020. See Note 12 to the Interim Financial Statements for further detail.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended March 31, 2021	2020
Royalties	$ 70.5	$ 57.5
Per BOE	$ 8.54	$ 6.43
Production taxes	$ 17.5	$ 15.4
Per BOE	$ 2.12	$ 1.73
Royalties and production taxes	$ 88.0	$ 72.9
Per BOE	$ 10.66	$ 8.16
Royalties and production taxes (% of crude oil and natural gas sales)	24.5%	25.5%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees and freehold mineral taxes. A large percentage of our production is from U.S. properties where royalty rates are generally higher than in Canada. Royalties and production taxes for the three months ended March 31, 2021 were $88.0 million, an increase of 21% from the same period in 2020. Total royalties increased due to higher realized prices and revenues. The decrease in royalty rate is primarily due to improved natural gas and natural gas liquids prices as these products have a lower royalty rate.

We expect annual royalties and production taxes in 2021 to average 26% of crude oil and natural gas sales before transportation.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended March 31, 2021	2020
Operating expenses	$ 64.5	$ 79.0
Per BOE	$ 7.82	$ 8.84

For the three months ended March 31, 2021, operating expenses were $64.5 million, or $7.82/BOE, a decrease of $14.5 million, or $1.02/BOE, from the same period in 2020. This decrease was primarily due to lower U.S. crude oil production which has higher per BOE operating costs and a stronger Canadian dollar when compared to the same period in 2020.

We expect operating expenses of $8.25/BOE in 2021, an increase from the first quarter of 2021 due to the expected increase in our crude oil and natural gas liquids production weighting with the Bruin and Hess acquisitions.

Transportation Costs

	Three months ended March 31,			
($ millions, except per BOE amounts)		2021		2020
Transportation costs	$	32.8	$	35.3
Per BOE	$	3.98	$	3.95

For the three months ended March 31, 2021, transportation costs were $32.8 million, or $3.98/BOE, compared to $35.3 million, or $3.95/BOE, for the same period in 2020. This represents a decrease of $2.5 million in total transportation costs and an increase of $0.03/BOE. The reduction in transportation costs was primarily due to the impact of a stronger Canadian dollar compared to the same period in 2020.

We expect transportation costs of $3.85/BOE in 2021.

Netbacks

The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A.

	Three months ended March 31, 2021					
Netbacks by Property Type		**Crude Oil**		**Natural Gas**		**Total**
Average Daily Production		55,652 BOE/day		216,115 Mcfe/day		91,671 BOE/day
Netback[(1)] $ per BOE or Mcfe		(per BOE)		(per Mcfe)		(per BOE)
Crude oil and natural gas sales	$	59.02	$	3.27	$	43.55
Royalties and production taxes		(15.09)		(0.63)		(10.66)
Operating expenses		(12.17)		(0.18)		(7.82)
Transportation costs		(3.06)		(0.90)		(3.98)
Netback before hedging	$	28.70	$	1.56	$	21.09
Cash hedging gains/(losses)		(4.02)		0.04		(2.35)
Netback after hedging	$	24.68	$	1.60	$	18.74
Netback before hedging ($ millions)	$	143.7	$	30.3	$	174.0
Netback after hedging ($ millions)	$	123.6	$	31.0	$	154.6

	Three months ended March 31, 2020					
Netbacks by Property Type		**Crude Oil**		**Natural Gas**		**Total**
Average Daily Production		59,226 BOE/day		233,898 Mcfe/day		98,209 BOE/day
Netback[(1)] $ per BOE or Mcfe		(per BOE)		(per Mcfe)		(per BOE)
Crude oil and natural gas sales	$	44.46	$	2.16	$	31.96
Royalties and production taxes		(11.94)		(0.40)		(8.16)
Operating expenses		(13.35)		(0.33)		(8.84)
Transportation costs		(2.92)		(0.92)		(3.95)
Netback before hedging	$	16.25	$	0.51	$	11.01
Cash hedging gains/(losses)		6.12		—		3.69
Netback after hedging	$	22.37	$	0.51	$	14.70
Netback before hedging ($ millions)	$	87.6	$	10.8	$	98.4
Netback after hedging ($ millions)	$	120.6	$	10.8	$	131.4

(1) See "Non-GAAP Measures" in this MD&A

Total netbacks before and after hedging for the three months ended March 31, 2021, were higher compared to the same period in 2020, primarily due to higher realized prices partially offset by lower production.

For the three months ended March 31, 2021, our crude oil properties accounted for 83% of our total netback before hedging, compared to 89% during the same period in 2020.

General and Administrative ("G&A") Expenses

Total G&A expenses include share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans"). See Note 13 and Note 16(b) to the Interim Financial Statements for further details.

	Three months ended March 31,	
($ millions)	2021	2020
Cash:		
G&A expense	$ 13.1	$ 12.2
Share-based compensation expense	2.8	(2.7)
Non-Cash:		
Share-based compensation expense	1.1	7.7
Equity swap loss/(gain)	(0.6)	1.9
G&A expense	(0.1)	0.1
Total G&A expenses	$ 16.3	$ 19.2

	Three months ended March 31,	
(Per BOE)	2021	2020
Cash:		
G&A expense	$ 1.59	$ 1.37
Share-based compensation expense	0.33	(0.31)
Non-Cash:		
Share-based compensation expense	0.14	0.86
Equity swap loss/(gain)	(0.07)	0.21
G&A expense	(0.01)	0.01
Total G&A expenses	$ 1.98	$ 2.14

Cash G&A expenses for the three months ended March 31, 2021 were $13.1 million or $1.59/BOE, compared to $12.2 million, or $1.37/BOE, for the same period in 2020. Cash G&A expenses were slightly higher compared to the same period in 2020, due to timing of expenses and increased on a per BOE basis due to lower production.

During the first quarter of 2021, we reported a cash SBC expense of $2.8 million compared to a recovery of $2.7 million for the same period in 2020. The expense was due to the increase in our share price on our outstanding Director Deferred Share Units. Non-cash SBC expense for the three months ended March 31, 2021 was $1.1 million, or $0.14/BOE, compared to an expense of $7.7 million, or $0.86/BOE, during the same period in 2020 as a result of lower performance multipliers on our outstanding Performance Share Units ("PSUs").

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. In the first quarter of 2021, we recorded a mark-to-market gain of $0.6 million on these contracts, compared to a loss of $1.9 million for the same period in 2020.

We expect cash G&A expenses of $1.25/BOE in 2021, a decrease from the first quarter of 2021 primarily due to an increase in production as a result of the Bruin and Hess acquisitions.

Interest Expense

For the three months ended March 31, 2021, we recorded total interest expense of $6.8 million, compared to $8.9 million for the same period in 2020. The decrease in interest expense was primarily due to the repayment of a portion of our 2009 and 2012 senior notes during the second quarter of 2020 and the impact of a stronger Canadian dollar on our U.S. dollar denominated interest expense. The decrease was partially offset by additional interest expense on our US$400 million term loan, which was used to fund a portion of the Bruin Acquisition.

At March 31, 2021, approximately 49% of our debt was based on fixed interest rates and 51% on floating interest rates with weighted average interest rates of 4.4% and 1.8%, respectively. See Note 9 to the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended March 31, 2021	2020
Realized foreign exchange (gain)/loss:		
Foreign exchange (gain)/loss on settlements	$ 0.3	$ (0.1)
Translation of U.S. dollar cash held in Canada (gain)/loss	(0.5)	(3.1)
Unrealized foreign exchange (gain)/loss	0.3	(2.4)
Total foreign exchange (gain)/loss	$ 0.1	$ (5.6)
USD/CDN average exchange rate	1.27	1.34
USD/CDN period end exchange rate	1.26	1.41

For the three months ended March 31, 2021, we recorded a foreign exchange loss of $0.1 million compared to a gain of $5.6 million for the same period in 2020. Realized foreign exchange gains and losses relate primarily to day-to-day transactions recorded in foreign currencies and the translation of our U.S. dollar denominated cash held in Canada, while unrealized foreign exchange gains and losses are recorded on the translation of our U.S. dollar denominated working capital held in Canada at each period end.

At March 31, 2021, US$385.4 million of senior notes outstanding and the US$400 million term loan were designated as net investment hedges. For the three months ended March 31, 2020, Other Comprehensive Income/(Loss) included an unrealized gain of $8.5 million, on our U.S. dollar denominated senior notes and term loan.

Capital Investment

($ millions)	Three months ended March 31, 2021	2020
Capital spending(1)	$ 65.5	$ 163.6
Office capital(1)	0.4	1.9
Sub-total	65.9	165.5
Property and land acquisitions	$ 3.4	$ 2.3
Bruin Acquisition(2)	625.2	—
Property divestments	(5.0)	(5.6)
Sub-total	623.6	(3.3)
Total	$ 689.5	$ 162.2

(1) Excludes changes in non-cash investing working capital. See Note 18(c) to the Interim Financial Statements for further details.
(2) Excludes asset retirement obligations assumed with the Bruin Acquisition.

Capital spending for the three months ended March 31, 2021 totaled $65.5 million compared to $163.6 million for the same period in 2020. During the first quarter of 2021, we spent $55.8 million on our U.S. crude oil properties, $5.0 million on our Marcellus natural gas assets and $2.9 million on our Canadian waterflood properties.

During the first quarter of 2021, we completed the Bruin Acquisition for total cash consideration of $528.6 million with $625.2 million allocated to PP&E, excluding the assumed asset retirement obligation. Additionally, we completed $3.4 million in property and land acquisitions compared to $2.3 million during the same period in 2020. Property divestments for the three months ended March 31, 2021 were $5.0 million compared to $5.6 million for the same period in 2020.

Subsequent to the quarter, we entered into a purchase and sale agreement to acquire certain assets in the Williston Basin from Hess for total cash consideration of US$312.0 million, subject to certain customary purchase price adjustments. The Hess Acquisition closed on April 30, 2021.

Our capital spending guidance range for 2021 is $360 to $400 million.

Depletion, Depreciation and Accretion ("DD&A")

($ millions, except per BOE amounts)	Three months ended March 31, 2021	2020
DD&A expense	$ 46.5	$ 95.2
Per BOE	$ 5.47	$ 10.65

DD&A of PP&E is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2021, DD&A expense decreased compared to the same period in 2020 mainly due to the impact of previous PP&E impairments.

Impairment

PP&E

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves using SEC constant prices ("Standardized Measure"). SEC prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. The Standardized Measure is not related to Enerplus' investment criteria and is not a fair value based measurement, but rather a prescribed accounting calculation. Impairments are non-cash and are not reversed in future periods under U.S. GAAP. See Note 7(b) to the Interim Financial Statements for trailing twelve month prices.

Trailing twelve month average crude oil and natural gas prices declined throughout 2020 and improved in the first quarter of 2021. For the three months ended March 31, 2021, we recorded a non-cash PP&E impairment of $4.3 million related to our Canadian assets. There was no impairment recorded for the same period in 2020. We requested and received a temporary exemption from the SEC to exclude the properties acquired in the Bruin Acquisition in the U.S. full cost ceiling test, for the first, second, third and fourth quarters of 2021.

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. For the remainder of 2021, the primary factors include future first-day-of-the-month commodity prices, reserves revisions, capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. See "Risk Factors and Risk Management - Risk of Impairment of Oil and Gas Properties, and Deferred Tax Assets" in the Annual MD&A.

Asset Retirement Obligation

In connection with our operations, we incur abandonment, reclamation and remediation costs related to assets, such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on the Condensed Consolidated Balance Sheet are based on management's estimate of our net ownership interest, costs to abandon, reclaim and remediate and the timing of the costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation, using a weighted average credit-adjusted risk-free rate of 5.33%, to be $156.7 million at March 31, 2021, compared to $130.2 million at December 31, 2020, using a weighted average credit-adjusted risk-free rate of 5.35%. The increase in the net present value of our asset retirement obligation is largely due to $27.8 million of additional liability assumed in connection with the Bruin Acquisition. For the three months ended March 31, 2021, asset retirement obligation settlements were $7.1 million, compared to $10.8 million during the same period in 2020.

For the three months ended March 31, 2021, Enerplus benefited from $1.7 million in provincial government grants to support the cleanup of inactive or abandoned crude oil and natural gas wells in Canada. These programs provide funding directly to oil field service contractors engaged by Enerplus to perform abandonment, remediation, and reclamation work. See Note 3 and10 to the Interim Financial Statements for further details.

Leases

Enerplus recognizes right-of-use ("ROU") assets and lease liabilities on the Condensed Consolidated Balance Sheet for qualifying leases with a term greater than 12 months. We incur lease payments related to office space, drilling rig commitments, vehicles, and other equipment. Total lease liabilities are based on the present value of lease payments over the lease term. Total ROU assets represent our right to use an underlying asset for the lease term. At March 31, 2021, our total lease liability was $36.0 million (December 31, 2020 - $36.8 million). In addition, ROU assets of $32.2 million were recorded, which equate to our lease liabilities less lease incentives (December 31, 2020 - $32.9 million). See Note 11 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended March 31,	
($ millions)	2021	2020
Current tax expense/(recovery)	$ —	$ —
Deferred tax expense/(recovery)	11.0	109.4
Total tax expense/(recovery)	$ 11.0	$ 109.4

We recorded a total tax expense of $11.0 million for the period ended March 31, 2021 compared to $109.4 million for the same period in 2020. The expense in 2021 was primarily due to income reported in the U.S. compared to the same period in 2020 where we recorded a valuation allowance against a portion of our Canadian deferred income tax assets.

We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not all or a portion of our deferred income tax assets will not be realized. We have considered available positive and negative evidence including future taxable income and reversing existing temporary differences in making this assessment. This assessment is primarily the result of projecting future taxable income using total proved and probable forecast average prices and costs. There is risk of a valuation allowance in future periods if commodity prices weaken or other evidence indicates that some of our deferred income tax assets will not be realized. See "Risk Factors and Risk Management – Risk of Impairment of Oil and Gas Properties and Deferred Tax Assets" in the Annual MD&A. A full valuation allowance has been recorded against our deferred income tax assets related to capital items. Our overall net deferred income tax asset is $593.3 million as at March 31, 2021 (December 31, 2020 - $607 million).

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess liquidity and leverage, including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging, share repurchases and dividend levels. We also assess our leverage relative to our most restrictive debt covenant under our bank facility, term loan and senior notes, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At March 31, 2021, our senior debt to adjusted EBITDA ratio was 1.8x and our net debt to adjusted funds flow ratio was 2.1x, which does not include the trailing adjusted funds flow associated with the Bruin Acquisition. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate liquidity. Refer to the definitions and footnotes below.

Total debt net of cash at March 31, 2021 increased to $794.2 million, compared to $376.0 million at December 31, 2020. Total debt was comprised of $983.2 million in senior notes and the term loan less $189.0 million in cash. The increase was due to funding a portion of the Bruin Acquisition using a US$400 million term loan entered into on March 10, 2021. Our next scheduled senior note repayments of US$59.6 million and US$22.0 million are due in May and June 2021, respectively, with remaining maturities extending to 2026. At March 31, 2021, we were undrawn on our bank facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 57% for the three months ended March 31, 2021, compared to 152% for the same period in 2020.

Subsequent to the quarter, the Board of Directors approved a 10% increase to the dividend to $0.033 per share paid quarterly, from $0.01 per share paid monthly previously. We expect to fund the increase though the incremental free cash flow generated by the business.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, decreased to $195.0 million at March 31, 2021 from $257.8 million at December 31, 2020. Our working capital varies due to the timing of the cash realization of our current assets and current liabilities, and the current level of business activity, including our capital spending program, along with commodity price volatility. At March 31, 2021 our accrued revenue receivable increased by $64.2 million as a result of higher commodity prices and production compared to December 31, 2020. We expect to finance our working capital deficit and ongoing working capital requirements through cash, adjusted funds flow and our bank facility. We have sufficient liquidity to meet our financial commitments for the near term.

During the first quarter of 2021, Enerplus acquired all the outstanding equity interests of Bruin for total cash consideration of approximately US$418 million, subject to final purchase price adjustments. Enerplus did not assume any debt of Bruin as a part of the Bruin Acquisition.

A portion of the purchase price of the Bruin Acquisition was funded with a new three-year, senior unsecured US$400 million term loan. The term loan includes financial and other covenants and pricing consistent with Enerplus' bank facility. Following the announcement of the Bruin Acquisition, Enerplus completed a bought deal equity financing, issuing 33.1 million common shares at a price of $4.00 per share for gross proceeds of $132.3 million ($127.2 million, net of issuance costs less tax). A portion of the net proceeds were used to fund the remainder of the Bruin Acquisition.

On April 8, 2021, Enerplus announced that it has entered into an agreement to acquire certain assets from Hess for total consideration of US$312 million, subject to customary purchase price adjustments. The Hess Acquisition closed on April 30, 2021 and was funded using cash and by drawing on our bank facility.

Subsequent to the quarter, we increased and extended our senior, unsecured, covenant-based bank credit facility to US$900 million from US$600 million with a maturity of October 31, 2025. As part of the extension, the company transitioned the facility to a sustainability-linked credit facility incorporating environmental, social and governance ("ESG")-linked incentive pricing terms which reduce or increase the borrowing costs by up to 5 basis points as Enerplus' sustainability performance targets ("SPT") are exceeded or missed. The SPTs are based on the following ESG goals of the company:

- **GHG Emissions:** continuous progress toward Enerplus' stated goal of a 50% reduction in corporate Scope 1 and 2 greenhouse gas emissions intensity by 2030, using 2019 as a baseline and measurement based on Enerplus' annual internal targets

- **Water Management:** achieve a 50% reduction in freshwater usage in corporate well completions by 2025 or earlier compared to 2019, with progress to be measured on an annual basis over the life of the credit facility

- **Health & Safety:** achieve and maintain a 25% reduction in the Company's Lost Time Injury Frequency, based on a trailing 3-year average, relative to a 2019 baseline

At March 31, 2021, we were in compliance with all covenants under our bank facility, the term loan and outstanding senior notes. If we exceed or anticipate exceeding our covenants, we may be required to repay, refinance or renegotiate the terms of the debt. See "Risk Factors – Debt covenants of the Corporation may be exceeded with no ability to negotiate covenant relief" in the Annual Information Form. Our bank facility, term loan and senior note purchase agreements have been filed under our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at March 31, 2021:

Covenant Description		March 31, 2021
Bank Credit Facility/Term Loan:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	1.8x
Total debt to adjusted EBITDA (1)	4.0x	1.8x
Total debt to capitalization	55%	36%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	1.8x
Senior debt to consolidated present value of total proved reserves(3)	60%	42%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	21.5x

Definitions
"Senior debt" is calculated as the sum of drawn amounts on our bank credit facility, term loan, outstanding letters of credit and the principal amount of senior notes.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended March 31, 2021 was $157.3 million and $565.7 million, respectively.
"Total debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.
"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes
(1) See "Non-GAAP Measures" in this MD&A for a reconciliation of adjusted EBITDA to net income.
(2) Senior debt to adjusted EBITDA for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.
(3) Senior debt to consolidated present value of total proved reserves is calculated annually on December 31 based on before tax reserves at forecast prices discounted at 10%.Total proved reserves at December 31, 2020 has been updated for reserves acquired through the Bruin Acquisition.

Dividends

	Three months ended March 31,	
($ millions, except per share amounts)	2021	2020
Dividends to shareholders(1)	$ 7.4	$ 6.7
Per weighted average share (Basic)	$ 0.03	$ 0.03

(1) Excludes changes in non-cash financing working capital. See Note 18(b) to the Interim Financial Statements for further details.

During the three months ended March 31, 2021, we declared total dividends of $7.4 million or $0.03 per share, compared to $6.7 million or $0.03 per share for the same period in 2020. The aggregate amount of dividends paid to shareholders have increased compared to the same period in 2020 due to an increase in common shares outstanding as a result of the bought deal equity financing completed in the first quarter of 2021.

Subsequent to the quarter, our Board of Directors approved a 10% increase to the dividend to $0.033 per share paid quarterly, from $0.01 per share paid monthly previously. The increased quarterly dividend is payable on June 15, 2021 to all shareholders of record at the close of business on May 28, 2021. The ex-dividend date for this payment is May 27, 2021. Given the April and May dividends have already been paid or declared, the change to quarterly payments beginning in June represents an incremental dividend payment of $5.6 million in the second quarter of 2021.

The dividend is part of our current strategy to return capital to shareholders. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Three months ended March 31, 2021	2020
Share capital ($ millions)	$ 3,236.1	$ 3,097.2
Common shares outstanding (thousands)	256,751	222,564
Weighted average shares outstanding – basic (thousands)	244,066	222,357
Weighted average shares outstanding – diluted (thousands)	246,898	223,300

For the three months ended March 31, 2021, a total of 2,014,193 units vested pursuant to our treasury settled LTI plans, including the impact of performance multipliers (2020 – 2,044,718). In total, 1,140,000 shares were issued from treasury and $11.9 million was transferred from paid-in capital to share capital (2020 – 1,160,000; $13.8 million). We elected to cash settle the remaining units related to the required tax withholdings (2021 – $4.5 million, 2020 – $7.2 million).

During the three months ended March 31, 2021, we issued 33,062,500 common shares at a price of $4.00 per common share for gross proceeds of $132.3 million ($127.2 million net of issue costs less tax) pursuant to a bought deal offering under our base shelf prospectus.

As of May 5, 2021, we had 256,750,100 common shares outstanding. In addition, an aggregate of 10,883,962 common shares may be issued to settle outstanding grants under the PSUs and Restricted Share Unit plans assuming the maximum performance multiplier of 2.0 times for the PSUs.

For further details, see Note 16 to the Interim Financial Statements.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended March 31, 2021			Three months ended March 31, 2020		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	7,190	35,275	42,465	7,836	41,208	49,044
Natural gas liquids (bbls/day)	500	6,081	6,581	710	4,636	5,346
Natural gas (Mcf/day)	10,066	245,683	255,749	14,913	248,000	262,913
Total average daily production (BOE/day)	9,368	82,303	91,671	11,032	87,177	98,209
Pricing(2)						
Crude oil (per bbl)	$ 56.36	$ 69.57	$ 67.34	$ 38.78	$ 53.68	$ 51.30
Natural gas liquids (per bbl)	40.78	35.79	36.17	23.90	11.01	12.72
Natural gas (per Mcf)	3.94	3.47	3.48	2.18	2.07	2.08
Capital Expenditures						
Capital spending	$ 4.7	$ 60.8	$ 65.5	$ 11.8	$ 151.8	$ 163.6
Acquisitions	1.1	627.5	628.6	1.1	1.2	2.3
Divestments	(5.0)	—	(5.0)	—	(5.6)	(5.6)
Netback(3) **Before Hedging**						
Crude oil and natural gas sales	$ 42.2	$ 317.1	$ 359.3	$ 32.8	$ 252.8	$ 285.6
Royalties	(7.6)	(62.9)	(70.5)	(5.7)	(51.8)	(57.5)
Production taxes	(0.5)	(17.0)	(17.5)	(0.3)	(15.1)	(15.4)
Operating expenses	(11.8)	(52.7)	(64.5)	(17.5)	(61.5)	(79.0)
Transportation costs	(2.1)	(30.7)	(32.8)	(2.1)	(33.2)	(35.3)
Netback before hedging	$ 20.2	$ 153.8	$ 174.0	$ 7.2	$ 91.2	$ 98.4
Other Expenses						
Asset impairment	$ 4.3	$ —	$ 4.3	$ —	$ —	$ —
Commodity derivative instruments loss/(gain)	69.8	—	69.8	(131.3)	—	(131.3)
Total G&A (including SBC)	6.7	9.6	16.3	(0.3)	19.5	19.2

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See "Non-GAAP Measures" section in this MD&A.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Crude Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2021				
First Quarter	$ 288.8	$ 14.7	$ 0.06	$ 0.06
Total 2021	$ 288.8	$ 14.7	$ 0.06	$ 0.06
2020				
Fourth Quarter	$ 195.1	$ (204.2)	$ (0.92)	$ (0.92)
Third Quarter	191.9	(112.8)	(0.51)	(0.51)
Second Quarter	122.1	(609.3)	(2.74)	(2.74)
First Quarter	228.1	2.9	0.01	0.01
Total 2020	$ 737.2	$ (923.4)	$ (4.15)	$ (4.15)
2019				
Fourth Quarter	$ 327.0	$ (429.1)	$ (1.93)	$ (1.93)
Third Quarter	318.9	65.1	0.28	0.28
Second Quarter	321.4	85.1	0.36	0.36
First Quarter	287.5	19.2	0.08	0.08
Total 2019	$ 1,254.8	$ (259.7)	$ (1.12)	$ (1.12)

Crude oil and natural gas sales, net of royalties, increased to $288.8 million during the first quarter of 2021 compared to $195.1 million in the fourth quarter of 2020. The increase in crude oil and natural gas sales, net of royalties, was a result of improved realized pricing in the first quarter of 2021 and increased production, when compared to the fourth quarter of 2020. We reported net income of $14.7 million during the first quarter of 2021 compared to a net loss of $204.2 million during the fourth quarter of 2020. The net loss in the fourth quarter of 2020 was due to non-cash PP&E impairments of $311.2 million, compared to impairment of $4.3 million during the first quarter of 2021.

Crude oil and natural gas sales, net of royalties, decreased in 2020 compared to 2019 due to lower commodity prices, and decreased production. We reported a net loss in 2020 due to a $994.8 million non-cash PP&E impairment and a $202.8 million non-cash goodwill impairment.

RECENT ACCOUNTING STANDARDS

We have not early adopted any accounting standard, interpretation or amendment that has been issued but is not yet effective. Our significant accounting policies remain unchanged from December 31, 2020, other than as described in Note 3 to the Interim Financial Statements, "Accounting Policy Changes".

2021 GUIDANCE

The following table summarizes our 2021 guidance and includes an eight month contribution from the Hess Acquisition, which closed April 30, 2021.

Summary of 2021 Annual Expectations(1)(2)	Target Annual Results
Capital spending	$360 - $400 million
Average annual production	111,000 - 115,000 BOE/day
Average annual crude oil and natural gas liquids production	68,500 - 71,500 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	26%
Operating expenses	$8.25/BOE
Transportation costs	$3.85/BOE
Cash G&A expenses	$1.25/BOE

Summary of 2021 Annual Expectations(1)(2)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.25)/bbl
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.55)/Mcf

(1) Guidance is based on the continued operation of DAPL.
(2) Excluding transportation costs.

NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities:

"Netback" is used by Enerplus and is useful to investors and securities analysts in evaluating operating performance of crude oil and natural gas assets. Netback is calculated as crude oil and natural gas sales less royalties, production taxes, operating expenses and transportation costs.

Calculation of Netback	**Three months ended March 31,**	
($ millions)	**2021**	**2020**
Crude oil and natural gas sales	$ 359.3	$ 285.6
Less:		
Royalties	(70.5)	(57.5)
Production taxes	(17.5)	(15.4)
Operating expenses	(64.5)	(79.0)
Transportation costs	(32.8)	(35.3)
Netback before hedging	$ 174.0	$ 98.4
Cash gains/(losses) on derivative instruments	(19.4)	33.0
Netback after hedging	$ 154.6	$ 131.4

"Adjusted funds flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating and financial performance, leverage and liquidity. Adjusted funds flow is calculated as cash flow from operating activities before asset retirement obligation expenditures and changes in non-cash operating working capital.

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	**Three months ended March 31,**	
($ millions)	**2021**	**2020**
Cash flow from operating activities	$ 37.2	$ 122.7
Asset retirement obligation expenditures	7.1	10.8
Changes in non-cash operating working capital	83.7	(20.3)
Adjusted funds flow	$ 128.0	$ 113.2

"Free cash flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating and financial performance, leverage and liquidity. Free cash flow is calculated as adjusted funds flow minus capital spending.

Calculation of Free Cash Flow	**Three months ended March 31,**	
($ millions)	**2021**	**2020**
Adjusted funds flow	$ 128.0	$ 113.2
Capital spending	(65.5)	(163.6)
Free cash flow	$ 62.5	$ (50.4)

"Adjusted net income/(loss)" is used by Enerplus and is useful to investors and securities analysts in evaluating the financial performance of the Company by understanding the impact of certain non-cash items and other items that the Company considers appropriate to adjust given the irregular nature and relevance to comparable companies. Adjusted net income/(loss) is calculated as net income/(loss) adjusted for unrealized derivative instrument gain/loss, asset impairment, unrealized foreign exchange gain/loss, the tax effect of these items, and the valuation allowance on our deferred income tax assets. No income tax rate adjustment on deferred taxes or goodwill impairment were recorded for the three months ended March 31, 2021 and 2020.

Calculation of Adjusted Net Income	**Three months ended March 31,**	
($ millions)	**2021**	**2020**
Net income/(loss)	$ 14.7	$ 2.9
Unrealized derivative instrument (gain)/loss	49.8	(96.4)
Asset impairment	4.3	—
Unrealized foreign exchange (gain)/loss	0.3	(2.4)
Tax effect on above items	(12.8)	23.4
Valuation allowance on deferred taxes	—	93.6
Adjusted net income/(loss)	$ 56.3	$ 21.1

"Total debt net of cash" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. Total debt net of cash is calculated as senior notes plus term loan plus any outstanding bank credit facility balance, minus cash and cash equivalents.

"**Net debt to adjusted funds flow ratio**" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The net debt to adjusted funds flow ratio is calculated as total debt net of cash divided by trailing twelve months of adjusted funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") and is not a debt covenant.

"**Adjusted payout ratio**" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. We calculate adjusted payout ratio as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	**Three months ended March 31,**	
($ millions)	**2021**	**2020**
Dividends	$ 7.4	$ 6.7
Capital and office expenditures	65.9	165.5
Sub-total	$ 73.3	$ 172.2
Adjusted funds flow	$ 128.0	$ 113.2
Adjusted payout ratio (%)	57%	152%

"**Adjusted EBITDA**" is used by Enerplus and its lenders to determine compliance with financial covenants under its bank credit facility and outstanding senior notes. Adjusted EBITDA is calculated on the trailing four quarters.

Reconciliation of Net Income to Adjusted EBITDA(1)	
($ millions)	**March 31, 2021**
Net income/(loss)	$ (911.5)
Add:	
Interest	26.3
Current and deferred tax expense/(recovery)	(359.2)
DD&A and asset impairment	1,446.3
Other non-cash charges(2)	180.4
Sub-total	$ 382.3
Adjustment for material acquisitions and divestments(3)	183.4
Adjusted EBITDA	$ 565.7

(1) Balances above at March 31, 2021 include the three months ended March 31, 2021 and the second, third and fourth quarter of 2020.
(2) Includes the change in fair value of commodity derivatives and equity swaps, non-cash SBC expense, non-cash G&A expense, non-cash amortization of debt issuance costs and unrealized foreign exchange gains/losses.
(3) EBITDA is adjusted for material acquisitions or divestments during the period with net proceeds greater than US$37.5 million as if that acquisition or disposition has been made at the beginning of the period.

In addition, the Company uses certain financial measures within the "Liquidity and Capital Resources" section of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "senior debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "senior debt to consolidated present value of total proved reserves" and "adjusted EBITDA to interest" and are used to determine the Company's compliance with financial covenants under its bank credit facility, term loan and outstanding senior notes. Calculation of such terms is described under the "Liquidity and Capital Resources" section of this MD&A.

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a - 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at March 31, 2021, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on January 1, 2021 and ended March 31, 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", “guidance”, "ongoing", "may", "will", "project", "plans", “budget”, "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected benefits of the Hess Acquisition and Bruin Acquisition; expected impact of the Hess Acquisition and Bruin Acquisition on Enerplus' operations and financial results; anticipated impact of the Hess Acquisition and Bruin Acquisition on Enerplus' future costs and expenses; expectations regarding the duration and overall impact of COVID-19, expected capital spending levels in 2021 and impact thereof on our production levels and land holdings; expected production volumes and 2021 production guidance; expected operating strategy in 2021, including the effect of Enerplus’ production curtailment on its properties, operations and financial position; 2021 average production volumes, timing thereof and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the expected effectiveness of such hedges in protecting our adjusted funds flow; anticipated production volumes subject to curtailment; the results from our drilling program and the timing of related production and ultimate well recoveries; oil and natural gas prices and differentials, our commodity risk management program in 2021 and expected hedging gains; expectations regarding our realized oil and natural gas prices; expected operating, transportation, cash G&A costs and share-based compensation and financing expenses; potential future non-cash PP&E impairments, as well as relevant factors that may affect such impairment; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending, and working capital requirements; expectations regarding payment of increased dividends; expectations regarding our ability to comply with debt covenants under our bank credit facility, term loan and outstanding senior notes; expectations regarding repayment of our outstanding senior notes, including sources of funds therefor; Enerplus' costs reduction initiatives and the expected cost savings therefrom in 2021; the amount of future cash dividends that we may pay to our shareholders; and our ESG initiatives, including GHG emissions and water reduction targets for 2021.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: the benefits of the Hess Acquisition and the Bruin Acquisition; that Enerplus will realize the expected impact of the Hess Acquisition and Bruin Acquisition on Enerplus' operations and financial results and on Enerplus' future costs and expenses will be as expected and as discussed in this MD&A; that we will conduct our operations and achieve results of operations as anticipated; the continued ability to operate DAPL and lack of court order restricting its operation, that our development plans will achieve the expected results; that lack of adequate infrastructure and/or low commodity price environment will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions, including expectations regarding the duration and overall impact of COVID-19; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to comply with our debt covenants; the availability of third party services; the extent of our liabilities; the rates used to calculate the amount of our future abandonment and reclamation costs and asset retirement obligations; and the availability of technology and process to achieve environmental targets. In addition, our expected 2021 capital expenditures, operating strategy and 2021 guidance described in this MD&A is based on the rest of the year prices and exchange rate of: a WTI price of between US$50.00 and US$55.00/bbl, a NYMEX price of US$3.00/Mcf, a Bakken crude oil price differential of US$3.25/bbls below WTI and a USD/CDN exchange rate of 1.27. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. Current conditions, economic and otherwise, render assumptions, although reasonable when made, subject to greater uncertainty.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: failure by Enerplus to realize anticipated benefits of the Hess Acquisition or the Bruin Acquisition; continued instability, or further deterioration, in global economic and market environment, including from COVID-19; continued low commodity prices environment or further decline and/or volatility in commodity prices; changes in realized prices of Enerplus’ products from those currently anticipated; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; the legal proceedings in connection with DAPL; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; changes in law or government programs or policies in Canada or the United States; and certain *other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in this MD&A, our Annual Information Form, our Annual MD&A and Form 40-F as at December 31, 2020).*

The forward-looking information contained in this MD&A speaks only as of the date of this MD&A. Enerplus does not undertake any obligation to publicly update or revise any forward-looking information contained herein, except as required by applicable laws.