Exhibit 99.1

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

The following discussion and analysis of financial results is dated May 5, 2022 and is to be read in conjunction with:

- the unaudited interim condensed consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") at and for the three months ended March 31, 2022 and 2021 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus at December 31, 2021 and 2020 and for the years ended December 31, 2021, 2020 and 2019; and
- the MD&A for the year ended December 31, 2021 (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, 2021 (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 prior period amounts have been restated to reflect the U.S. dollar as the reporting currency. 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. In accordance with U.S. GAAP, crude oil and natural gas sales are presented net of royalties in the Financial Statements. Unless otherwise stated, all production volumes and realized product prices information is presented on a "net" basis (after deduction of royalty obligations plus the Company's royalty interests) consistent with U.S. oil and gas reporting standards and thus, 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.

OVERVIEW

Production during the first quarter of 2022 averaged 92,196 BOE/day, a decrease of 10% compared to average production of 102,823 BOE/day in the fourth quarter of 2021, with crude oil and natural gas liquids production decreasing by 14% over the same period. Production decreased in North Dakota as expected, mainly due to production declines as completions activity resumed in March with the first wells coming on-stream at the end of the month. Due to strong operational execution and the continued optimization of our development plan and despite the impacts of the severe winter weather during the second quarter of 2022, we are increasing our annual average production guidance range for 2022 to 96,000 to 101,000 BOE/day, including 58,500 to 62,500 bbls/day in crude oil and natural gas liquids from 95,500 to 100,500 BOE/day, and 58,000 to 62,000 bbls/day in crude oil and natural gas liquids.

Capital spending during the first quarter of 2022 totaled $99.0 million, compared to $81.1 million during the fourth quarter of 2021, with the majority of the spending focused on our U.S. crude oil properties. We are revising our annual capital spending guidance for 2022 to between $400 to $440 million from $370 to $430 million primarily as a result of inflationary pressures due to the high commodity price environment and supply chain tightness, along with increased non-operated activity.

Our realized Bakken crude oil price differential narrowed to average $0.35/bbl below WTI during the first quarter of 2022 compared to $0.88/bbl below WTI during the fourth quarter of 2021. Bakken differentials in North Dakota continued to narrow due to continued improvement in demand, excess pipeline capacity in the region and strong prices for crude oil delivered to the U.S. Gulf Coast. Given the constructive outlook for Bakken crude oil prices and strong realizations year-to-date, we expect our 2022 realized Bakken oil price to be at par with WTI from a crude oil price differential of $0.50/bbl below WTI, previously.

Our realized Marcellus natural gas price differential narrowed to average $0.01/Mcf above NYMEX in the first quarter of 2022, compared to $1.70/Mcf below NYMEX during the fourth quarter of 2021, due to stronger spot prices in the region along with increased seasonal demand. We are maintaining our annual Marcellus natural gas price differential guidance to average $0.75/Mcf below NYMEX for 2022.

Operating expenses for the first quarter of 2022 increased to $83.2 million or $10.03/BOE, compared to $80.0 million or $8.46/BOE during the fourth quarter of 2021. The increase was primarily due to contracts with price escalators linked to WTI crude oil prices and the Consumer Price Index, and increased well service activity. Due to additional costs incurred to restore production following weather-related downtime during the second quarter of 2022, we are increasing the lower end of our operating expenses guidance to $9.75/BOE, from $9.50/BOE previously.

We reported net income of $33.2 million in the first quarter of 2022 compared to net income of $176.9 million in the fourth quarter of 2021. The decrease in net income recognized in the first quarter of 2022 was primarily due to a $133.0 million unrealized commodity derivative loss compared to an unrealized gain of $68.5 million in the fourth quarter of 2021. The commodity derivative loss is the result of higher commodity prices during the quarter due to the Ukraine/Russia conflict as well as tight global supply.

In the first quarter of 2022 cash flow from operating activities decreased to $196.0 million from $283.5 million in the fourth quarter of 2021. Adjusted funds flow[1] increased to $261.9 million compared to $258.5 million in the fourth quarter of 2021, primarily due to higher realized prices, offset by lower production.

At March 31, 2022, net debt was $572.3 million, comprised of senior notes, the outstanding balance on our sustainability-linked lending bank credit facility ("SLL Bank Credit Facility") and the revolving bank credit facility totaling $595.0 million, less cash on hand of $22.7 million. Our net debt to adjusted funds flow ratio[1] decreased to 0.7x from 0.9x in the fourth quarter of 2021.

During the first quarter of 2022, a total of $45.1 million was returned to shareholders through share repurchases and dividends.

Subsequent to the quarter, the Board of Directors approved an increase to our 2022 return of capital plan to a minimum of $350 million or 50% of annual free cash flow[1], whichever is greater, through dividends and share repurchases. In connection with this plan, the Board of Directors approved a 30% increase to the quarterly dividend to $0.043 per share, beginning June 2022. The increased dividend is equal to approximately $40 million on an annualized basis. The remaining $310 million or greater of shareholder returns are expected to be delivered through share repurchases, based on current market conditions. We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

RESULTS OF OPERATIONS

Production

Daily production for the first quarter of 2022 averaged 92,196 BOE/day, a decrease of 10% compared to average daily production of 102,823 BOE/day in the fourth quarter of 2021. The decrease is primarily the result of natural production declines as completions activity resumed in March with the first wells coming on-stream in late March. Production in the first quarter of 2022 was also impacted by the sale of our interests in the Sleeping Giant field in Montana and Russian Creek area in North Dakota in the Williston Basin (the "Sleeping Giant/Russian Creek Divestment"), which closed during the fourth quarter of 2021 and was producing approximately 2,400 BOE/day.

For the three months ended March 31, 2022, total production increased by 25% when compared to the same period in 2021, with crude oil and natural gas liquids production increasing by 42% over the same period. The increase in production was primarily due to our acquisition of Bruin E&P HoldCo, LLC ("Bruin" and the "Bruin Acquisition") and our acquisition of certain assets in the Williston Basin from Hess Bakken Investments II, LLC (the "Dunn County Acquisition"), each of which closed in the first half of 2021, slightly offset by the Sleeping Giant/Russian Creek Divestment in November 2021.

Our crude oil and natural gas liquids weighting for the three months ended March 31, 2022 increased to 61%, from 53% over the same period in 2021.

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[1] This financial measure is a non-GAAP financial measure. See "Non-GAAP and Other Financial Measures" section in this MD&A.

Average daily production volumes for the three months ended March 31, 2022 and 2021 are outlined below:

Average Daily Production Volumes	Three months ended March 31, 2022	2021	% Change
Light and medium oil (bbls/day)	2,172	2,341	(7%)
Heavy oil (bbls/day)	3,034	3,384	(10%)
Tight oil (bbls/day)	42,428	28,387	49%
Total crude oil (bbls/day)	47,634	34,112	40%
Natural gas liquids (bbls/day)	8,377	5,270	59%
Conventional natural gas (Mcf/day)	7,193	8,733	(18%)
Shale gas (Mcf/day)	209,918	197,216	6%
Total natural gas (Mcf/day)	217,111	205,949	5%
Total daily sales (BOE/day)	92,196	73,707	25%

Despite the impacts of the severe winter weather during the second quarter of 2022, we are increasing our average annual production guidance for 2022 to 96,000 to 101,000 BOE/day, including 58,500 to 62,500 bbls/day in crude oil and natural gas liquids from 95,500 to 100,500 BOE/day, and 58,000 to 62,000 bbls/day in crude oil and natural gas liquids.

Pricing

The prices received for crude oil and natural gas production directly impact our earnings, cash flow from operating activities, adjusted funds flow[1] and financial condition. The following table compares quarterly average benchmark prices, selling prices and differentials:

Pricing (average for the period)	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021
Benchmarks					
WTI crude oil ($/bbl)	$ 94.29	$ 77.19	$ 70.56	$ 66.07	$ 57.84
Brent (ICE) crude oil ($/bbl)	97.38	79.80	73.23	69.02	61.10
NYMEX natural gas – last day ($/Mcf)	4.95	5.83	4.01	2.83	2.69
CDN/US average exchange rate	0.79	0.79	0.79	0.81	0.79
CDN/US period end exchange rate	0.80	0.79	0.79	0.81	0.79
Enerplus selling price(1)					
Crude oil ($/bbl)	$ 91.95	$ 75.21	$ 67.22	$ 62.50	$ 53.24
Natural gas liquids ($/bbl)	37.78	38.77	29.91	18.47	28.55
Natural gas ($/Mcf)	4.62	3.92	3.00	1.96	2.76
Average differentials					
Bakken DAPL – WTI ($/bbl)	$ 0.71	$ 0.53	$ (0.68)	$ (0.40)	$ (2.63)
Brent (ICE) – WTI ($/bbl)	3.09	2.61	2.67	2.95	3.26
MSW Edmonton – WTI ($/bbl)	(2.96)	(3.10)	(4.07)	(3.11)	(5.24)
WCS Hardisty – WTI ($/bbl)	(14.53)	(14.64)	(13.58)	(11.49)	(12.47)
Transco Leidy monthly – NYMEX ($/Mcf)	(0.71)	(0.92)	(1.11)	(1.17)	(0.58)
Transco Z6 Non-New York monthly – NYMEX ($/Mcf)	1.42	(0.16)	(0.73)	(0.72)	0.17
Enerplus realized differentials(1)(2)					
Bakken crude oil – WTI ($/bbl)	$ (0.35)	$ (0.88)	$ (2.26)	$ (2.81)	$ (3.19)
Marcellus natural gas – NYMEX ($/Mcf)	0.01	(1.70)	(0.45)	(0.89)	(0.15)
Canada crude oil – WTI ($/bbl)	(16.31)	(13.82)	(12.87)	(11.65)	(12.88)

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

[1] This financial measure is a non-GAAP financial measure. See "Non-GAAP and Other Financial Measures" section in this MD&A.

CRUDE OIL AND NATURAL GAS LIQUIDS

During the first quarter of 2022, our realized crude oil sales price averaged $91.95/bbl, an increase of 22% compared to the fourth quarter of 2021 and consistent with the increase in benchmark WTI over the same period. Crude oil prices were impacted by the Ukraine/Russia conflict, the imposition of economic sanctions on Russia and the potential disruption of Russian crude oil production. Both the continued recovery of global crude oil demand due to increasing mobility post-coronavirus pandemic ("COVID-19") and uncertainty over the Organization of the Petroleum Exporting Countries Plus ("OPEC+") nations' ability to materially increase production provided support to global crude oil prices during the quarter.

Bakken crude oil price differentials continued to narrow due to an improvement in the supply and demand balance, excess pipeline capacity in the region, and strong prices for crude oil delivered to the U.S. Gulf Coast. Our realized Bakken crude oil price differential averaged $0.35/bbl below WTI during the first quarter of 2022, compared to $0.88/bbl below WTI during the fourth quarter of 2021. Given stronger year-to-date realizations, we expect our 2022 realized Bakken oil price to be at par with WTI from a crude oil price differential of $0.50/bbl below WTI, previously.

Our realized sales price for natural gas liquids averaged $37.78/bbl during the first quarter of 2022, a decrease of 3% compared to the fourth quarter of 2021.

NATURAL GAS

Our realized natural gas sales price averaged $4.62/Mcf during the first quarter of 2022, an increase of 18% compared to the fourth quarter of 2021, while the NYMEX benchmark price decreased by 15% over the same period. The difference in price realization versus the benchmark was due to the majority of our natural gas sales during the quarter being made in the daily spot markets, which outperformed the benchmark NYMEX last day pricing.

Our realized Marcellus sales price differential narrowed considerably compared to the previous quarter, as expected, due to seasonal demand and stronger spot prices in the region. Our differential in the quarter averaged $0.01/Mcf above NYMEX compared to $1.70/Mcf below NYMEX in the fourth quarter of 2021. A significant portion of our production receives prices reflecting market conditions south of New York at Transco Zone 6 Non-New York, which averaged $1.42/Mcf over NYMEX in the first quarter of 2022. We expect Marcellus differentials to widen for the remainder of 2022, due to the seasonal impact on natural gas prices in the region. Based on this, we are maintaining our Marcellus natural gas sales price differential guidance of $0.75/Mcf below NYMEX for 2022.

FOREIGN EXCHANGE

Fluctuations in the U.S. dollar will impact the amount of our Canadian dollar denominated amounts such as Canadian netbacks, capital spending, general and administrative ("G&A") expenses, and dividends paid to Canadian residents. The U.S. dollar ended slightly weaker in the first quarter of 2022 at 0.80 CDN/US, compared to 0.79 CDN/US at December 31, 2021. The average exchange rate during the first quarter of 2022 was consistent compared to the same period in 2021, averaging 0.79 CDN/US. U.S. dollar denominated working capital that is held in the Canadian parent entity will continue to result in unrealized foreign exchange gains and losses based on changes in the period end exchange rates. See Note 13 to the Financial Statements for further detail.

Price Risk Management

We have a price risk management program that considers our overall financial position and the economics of our capital expenditures.

At May 4, 2022, we have commodity derivative contracts in place for approximately 21,100 bbls/day of our expected crude oil production for the remainder of 2022 and 7,000 bbls/day during 2023. Our crude oil contracts are predominately three way collars. The three way collars provide us with exposure to 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. For natural gas, we have contracts in place for 100,000 Mcf/day of natural gas for the period of April 1, 2022 to October 31, 2022.

The following is a summary of our financial contracts in place at May 4, 2022:

	WTI Crude Oil ($/bbl) (1)(2)(3)				NYMEX Natural Gas ($/Mcf)(2)
	Apr 1, 2022 – June 30, 2022	**Apr 1, 2022 – Dec 31, 2022**	**Jan 1, 2023 – June 30, 2023**	**Jan 1, 2023 – Dec 31, 2023**	**Apr 1, 2022 – Oct 31, 2022**
Swaps					
Volume (Mcf/day)	–	–	–	–	40,000
Sold Puts	–	–	–	–	$ 3.40
Collars					
Volume (Mcf/day)	–	–	–	–	60,000
Volume (bbls/day)	12,500	17,000	10,000	2,000	–
Sold Puts	$ 58.00	$ 40.00	$ 60.00	–	–
Purchased Puts	$ 75.00	$ 50.00	$ 76.50	$ 5.00	$ 3.77
Sold Calls	$ 87.63	$ 57.91	$ 107.38	$ 75.00	$ 4.50

(1) The total average deferred premium spent on our outstanding crude oil contracts is $1.50/bbl from April 1, 2022 - December 31, 2022 and $1.25/bbl from January 1, 2023 - June 30, 2023.

(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 crude oil contracts were recorded at a fair value liability of $76.4 million. At March 31, 2022, the remaining liability was $16.3 million on the Condensed Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired contracts are recognized in Condensed Consolidated Statement of Income/(Loss) and the Condensed Consolidated Balance Sheets to reflect changes in crude oil prices from the date of closing of the Bruin Acquisition. See Note 16 to the Interim Financial Statements for further details.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	**Three months ended March 31,**	
($ millions)	**2022**	**2021**
Realized gains/(losses):		
Crude oil	$ (72.7)	$ (16.0)
Natural gas	(0.4)	0.6
Total realized gains/(losses)	$ (73.1)	$ (15.4)
Unrealized gains/(losses):		
Crude oil	$ (95.7)	$ (41.9)
Natural gas	(38.0)	1.0
Total unrealized gains/(losses)	$ (133.7)	$ (40.9)
Total gains/(losses)	$ (206.8)	$ (56.3)

	Three months ended March 31,	
(Per BOE)	**2022**	**2021**
Total realized gains/(losses)	$ (8.81)	$ (2.32)
Total unrealized gains/(losses)	(16.11)	(6.16)
Total commodity derivative instruments gains/(losses)	$ (24.92)	$ (8.48)

During the three months ended March 31, 2022, Enerplus realized losses of $72.7 million on our crude oil contracts compared to $16.0 million for the same period in 2021. In the three months ended March 31, 2022, realized losses of $0.4 million were recorded on our natural gas contracts compared to a realized gain of $0.6 million for the same period in 2021. Cash losses recorded during the three months ended March 31, 2022 were due to commodity prices exceeding the swap and sold call values on our commodity derivative contracts.

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 recorded as either an unrealized charge or gain to earnings. At March 31, 2022, the fair value of our crude oil and natural gas contracts was in a net liability position of $270.3 million (December 31, 2021 – $143.7 million). For the three months ended March 31, 2022, the change in the fair value of our crude oil contracts resulted in an unrealized loss of $95.7 million, compared to an unrealized loss of $41.9 million during the same period in 2021. For the three months ended March 31, 2022, we recorded an unrealized loss on our natural gas contracts of $38.0 million, compared to an unrealized gain of $1.0 million during the same period in 2021.

Crude Oil and Natural Gas Sales

($ millions, except per BOE amounts)	Three months ended March 31, 2022	2021
Crude oil and natural gas sales	$ 513.2	$ 228.4
Per BOE	$ 61.84	$ 34.43

Crude oil and natural gas sales for the three months ended March 31, 2022 were $513.2 million or $61.84/BOE, an increase from $228.4 million or $34.43/BOE for the same period in 2021. The increase in revenue was primarily due to additional production from the Bruin and Dunn County acquisitions completed during the first half of 2021 as well as higher commodity prices. See Note 11 to the Interim Financial Statements for further details.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended March 31, 2022	2021
Operating expenses	$ 83.2	$ 51.2
Per BOE	$ 10.03	$ 7.71

For the three months ended March 31, 2022, operating expenses were $83.2 million or $10.03/BOE, compared to $51.2 million or $7.71/BOE for the same period in 2021. The increase was primarily due to higher U.S. crude oil weighting in our production mix as a result of the Bruin and Dunn County acquisitions and increased liquids weighting to 61% compared to 53% for the same period in 2021 with higher associated operating costs. In addition, operating expenses increased due to contracts with price escalators linked to WTI crude oil prices and the Consumer Price Index, and increased well service activity.

Due to additional costs incurred to restore production following weather-related downtime during the second quarter of 2022, we are revising our expected operating expenses guidance for 2022 to average between $9.75/BOE to $10.50/BOE from $9.50/BOE to $10.50/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended March 31, 2022	2021
Transportation costs	$ 35.8	$ 25.9
Per BOE	$ 4.32	$ 3.91

For the three months ended March 31, 2022, transportation costs were $35.8 million or $4.32/BOE, compared to $25.9 million or $3.91/BOE for the same period in 2021. The increase in transportation costs was primarily a result of increased U.S. production with higher associated transportation costs and additional firm transportation commitments on the Dakota Access Pipeline (“DAPL”), compared to the same period in 2021 as a result of the Bruin Acquisition and participation in the DAPL expansion in August 2021.

We continue to expect transportation costs of $4.15/BOE in 2022.

Production Taxes

($ millions, except per BOE amounts)	Three months ended March 31, 2022	2021
Production taxes	$ 35.4	$ 13.8
Per BOE	$ 4.26	$ 2.09
Production taxes (% of crude oil and natural gas sales)	6.9%	6.1%

Production taxes include state production taxes, Pennsylvania impact fees and Canadian freehold mineral taxes and production surcharges.

Production taxes for the three months ended March 31, 2022 were $35.4 million, compared to $13.8 million for the same period in 2021. The increase was due to higher realized prices, compared to the same period in 2021.

We continue to expect production taxes to average 7% in 2022.

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, 2022		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	64,036 BOE/day	168,959 Mcfe/day	92,196 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 76.05	$ 4.92	$ 61.84
Operating expenses	(13.78)	(0.25)	(10.03)
Transportation costs	(3.86)	(0.89)	(4.32)
Production taxes	(6.01)	(0.05)	(4.26)
Netback before impact of commodity derivative contracts	$ 52.40	$ 3.73	$ 43.23
Realized hedging gains/(losses)	(12.61)	(0.03)	(8.81)
Netback after impact of commodity derivative contracts	$ 39.79	$ 3.70	$ 34.42
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 302.0	$ 56.8	$ 358.8
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 229.3	$ 56.4	$ 285.7

	Three months ended March 31, 2021		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	44,858 BOE/day	173,090 Mcfe/day	73,707 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 46.41	$ 2.63	$ 34.43
Operating expenses	(12.02)	(0.17)	(7.71)
Transportation costs	(3.00)	(0.89)	(3.91)
Production taxes	(3.34)	(0.02)	(2.09)
Netback before impact of commodity derivative contracts	$ 28.05	$ 1.55	$ 20.72
Realized hedging gains/(losses)	(3.96)	0.04	(2.32)
Netback after impact of commodity derivative contracts	$ 24.09	$ 1.59	$ 18.40
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 113.2	$ 24.3	$ 137.5
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 97.3	$ 24.8	$ 122.1

(1) This financial measure is a non-GAAP financial measure. See "Non-GAAP and Other Financial Measures" section in this MD&A.

Total netbacks before and after hedging for the three months ended March 31, 2022 were higher compared to the same period in 2021, primarily due to higher production and higher realized prices.

For the three months ended March 31, 2022, crude oil properties accounted for 84% of total netback before hedging, compared to 82% during the same period in 2021.

G&A Expenses

Total G&A expenses include cash G&A expenses and share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans"). See Note 12 and Note 15 to the Interim Financial Statements for further details.

($ millions)	Three months ended March 31, 2022	2021
Cash:		
G&A expense	$ 11.2	$ 10.4
Share-based compensation expense	2.1	2.2
Non-Cash:		
Share-based compensation expense	4.8	0.8
Equity swap gain	(0.4)	(0.5)
G&A recovery	(0.1)	(0.1)
Total G&A expenses	$ 17.6	$ 12.8

(Per BOE)	Three months ended March 31, 2022	2021
Cash:		
G&A expense	$ 1.35	$ 1.57
Share-based compensation expense	0.25	0.32
Non-Cash:		
Share-based compensation expense	0.58	0.13
Equity swap gain	(0.05)	(0.07)
G&A recovery	(0.01)	(0.01)
Total G&A expenses	$ 2.12	$ 1.94

Cash G&A expenses for the three months ended March 31, 2022 were $11.2 million or $1.35/BOE, compared to $10.4 million or $1.57/BOE for the same period in 2021. Total cash G&A expenses increased slightly on a total dollar basis, however, were lower on a per BOE basis compared to the same period in 2021 due to higher production.

SBC can be equity settled or cash-settled, depending on the underlying plan to which it relates. SBC that is cash-settled was $2.1 million, or $0.25/BOE, for the first three months ended March 31, 2022, compared to $2.2 million, or $0.32/BOE, for the same period in 2021. The increase was due to the impact of the higher share price during 2022. Equity settled non-cash SBC was $4.8 million, or $0.58/BOE, for the three months ended March 31, 2022, compared to $0.8 million, or $0.13/BOE, for the same period in 2021. Performance Share Units ("PSUs"), as one of the equity settled LTI plans, are impacted by performance multipliers. For the three months ended March 31, 2022, the multipliers were higher, resulting in an increase in expense compared to the same period in 2021.

Enerplus has hedged a portion of the outstanding cash settled units under our LTI plans. In the first quarter of 2022, we recorded a market-to-market gain of $0.4 million on these contracts, compared to a gain of $0.5 million for the same period in 2021, as a result of the higher share price.

We continue to expect cash G&A expenses of $1.25/BOE for 2022.

Interest Expense

For the three months ended March 31, 2022, we recorded a total interest expense of $6.1 million, compared to $5.6 million for the same period in 2021. The increase was primarily due to higher debt levels incurred to fund the Buin and Dunn County acquisitions, partially offset by the final repayment of our 2009 senior notes and scheduled repayment of our 2012 senior notes, which carry higher interest rates than our SLL Bank Credit Facility and revolving bank credit facility (together referred to as the "Bank Credit Facilities").

At March 31, 2022, approximately 51% of Enerplus' debt was based on fixed interest rates and 49% on floating interest rates (December 31, 2021 – 43% fixed and 57% floating), with weighted average interest rates of 4.2% and 1.9%, respectively. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended March 31, 2022	2021
Realized:		
Foreign exchange (gain)/loss	$ (0.3)	$ (0.5)
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company	—	0.4
Unrealized:		
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company	1.2	0.1
Total foreign exchange (gain)/loss	$ 0.9	$ —
CDN/US average exchange rate	0.79	0.79
CDN/US period end exchange rate	0.80	0.79

For the three months ended March 31, 2022, Enerplus recorded a foreign exchange loss of $0.9 million, compared to no gain or loss recorded for the same period in 2021. Realized foreign exchange gains and losses relate primarily to day-to-day transactions recorded in foreign currencies as well as 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, 2022, $303.8 million of senior notes outstanding and $293.0 million drawn on the Bank Credit Facilities were designated as net investment hedges against the investment in our U.S. subsidiary. As a result, unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt are included in Other Comprehensive Income/(Loss). For the three months ended March 31, 2022, Other Comprehensive Income/(Loss) included an unrealized gain of $5.4 million on our U.S. dollar denominated senior notes and Bank Credit Facilities (2021 – $5.7 million gain).

Property, Plant and Equipment ("PP&E")

($ millions)	Three months ended March 31, 2022	2021
Capital spending(1)	$ 99.0	$ 51.8
Office capital	0.3	1.3
Sub-total	99.3	53.1
Bruin Acquisition	$ —	$ 494.7
Property and land acquisitions	1.9	2.4
Property divestments	(6.6)	(4.0)
Sub-total	(4.7)	493.1
Total	$ 94.6	$ 546.2

(1) Excludes changes in non-cash investing working capital. See Note 17 to the Interim Financial Statements for further details.

Capital spending for the three months ended March 31, 2022 totaled $99.0 million, compared to $51.8 million for the same period in 2021. The increase is mainly due to increased capital activity on our North Dakota properties. Capital spending during the first quarter of 2022 included $82.1 million on our U.S. crude oil properties and $14.5 million on our Marcellus natural gas assets.

During the first quarter of 2021, we completed the Bruin Acquisition for total cash consideration of $465.0 million or $420.2 million after purchase price adjustments with $494.7 million allocated to PP&E, excluding the assumed asset retirement obligation. Property divestments for the three months ended March 31, 2022 were $6.6 million compared to $4.0 million for the same period in 2021.

We are increasing our annual capital spending guidance for 2022 to between $400 to $440 million from $370 to $430 million primarily as a result of inflationary pressures due to the high commodity price environment and supply chain tightness, along with increased non-operated activity and associated costs.

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

($ millions, except per BOE amounts)	Three months ended March 31, 2022	2021
DD&A expense	$ 66.7	$ 36.7
Per BOE	$ 8.04	$ 5.53

DD&A related to PP&E is recognized using the unit of production method based on proved reserves. For the three months ended March 31, 2022, Enerplus recorded DD&A expense of $66.7 million, compared to $36.7 million for the same period in 2021. DD&A expense increased as a result of higher overall production volumes and the net impact of acquisitions, divestments and previous PP&E impairments.

Impairment

PP&E

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country cost centre basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves ("Standardized Measure"), using constant prices as defined by the SEC guidelines. 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.

Trailing twelve month average crude oil and natural gas prices improved throughout 2021, and into the first quarter of 2022. There were no impairments for the three months ended March 31, 2022. For the three months ended March 31, 2021, we recorded a PP&E impairment of $3.4 million related to our Canadian assets.

Many factors influence the allowed ceiling value compared to 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 2022, 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 (“ARO”)

In connection with our operations, we incur abandonment, reclamation and remediation costs related to assets, such as surface leases, wells, facilities and pipelines. Total ARO included on the Condensed Consolidated Balance Sheet is based on management’s estimate of our net ownership interest, costs to abandon, reclaim and remediate, the timing of the costs to be incurred in future periods and estimates for inflation. We have estimated the net present value of our asset retirement obligation, to be $144.6 million at March 31, 2022, compared to $132.8 million at December 31, 2021.

For the three months ended March 31, 2022, ARO settlements were $8.8 million, compared to $5.6 million during the same period in 2021.

Enerplus benefited from provincial government assistance to support the cleanup of inactive or abandoned crude oil and natural gas wells. These programs provide direct funding to oil field service contractors engaged by Enerplus to perform abandonment, remediation, and reclamation work. The funding received by the contractor is reflected as a reduction to ARO. For the three months ended March 31, 2022, Enerplus benefitted from $0.4 million in government assistance (2021 – $1.3 million). See Note 9 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, including lease payments relating 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, 2022, our total lease liability was $27.2 million (December 31, 2021 - $28.9 million). In addition, ROU assets of $24.5 million were recorded, which relate to our lease liabilities less lease incentives (December 31, 2021 - $26.1 million). See Note 10 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended March 31,	
($ millions)	2022	2021
Current tax expense/(recovery)	$ 5.0	$ —
Deferred tax expense/(recovery)	9.8	8.7
Total tax expense/(recovery)	$ 14.8	$ 8.7

For the three months ended March 31, 2022, we recorded a current tax expense of $5.0 million compared to nil tax expense recorded for the same period in 2021. Current tax consists of U.S. federal and state tax as a result of higher net income in 2022 as we could potentially utilize the full amount of our net operating loss carryforwards in 2022. Many factors influence taxable income including future commodity prices, production levels, development activities, capital spending, and overall profitability. As a result of the higher commodity prices, we are updating our current tax guidance from $10.0 million to $20.0 million – $30.0 million (2% – 3% of adjusted funds flow before tax) for 2022 assuming WTI of $85.00/bbl and NYMEX of $5.00/Mcf.

For the three months ended March 31, 2022, we recorded a deferred income tax expense of $9.8 million, compared to an expense of $8.7 million for the same period in 2021.

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. For the three months ended March 31, 2022, no valuation allowance was recorded against our U.S. and Canadian income related deferred tax assets, however, 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 $374.2 million at March 31, 2022 (December 31, 2021 - $380.9 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, commodity derivative contracts, share repurchases and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, 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, 2022, our senior debt to adjusted EBITDA ratio was 0.7x and our net debt to adjusted funds flow ratio[1] was 0.7x. Although a non-GAAP measure that 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.

Net debt at March 31, 2022 decreased to $572.3 million, compared to $640.4 million at December 31, 2021. Total debt was comprised of our senior notes, and Bank Credit Facilities, totaling $595.0 million, less cash on hand of $22.7 million. During the quarter, we converted our senior unsecured, covenant-based $400 million term loan maturing on March 9, 2024 into a revolving bank credit facility with no other amendments.

At March 31, 2022 through our Bank Credit Facilities, we had total credit capacity of $1.3 billion, of which $293.0 million was drawn. We expect to finance our working capital requirements and upcoming senior note repayments through cash, adjusted funds flow and our credit capacity. We have sufficient liquidity to meet our financial commitments for the near term.

Our reinvestment rate[1] was 38% for the three months ended March 31, 2022 compared to 51% for the same period in 2021. We are committed to free cash flow generation and are targeting a long-term capital spending reinvestment rate[1] of less than 75% of annual adjusted funds flow[1].

During the first quarter of 2022, a total of $45.1 million was returned to shareholders through share repurchases and dividends, compared to $5.6 million for the same period in 2021. A total of 3,134,700 common shares were repurchased and cancelled under the Normal Course Issuer Bid (“NCIB”) at an average price of $11.87 per share, for total consideration of $37.2 million. We did not have a NCIB in place during the three months ended March 31, 2021. Subsequent to March 31, 2022 and up to and including May 4, 2022, we repurchased 1,494,996 common shares under the NCIB at an average price of $12.61 per share, for total consideration of $18.9 million.

[1] This financial measure is a non-GAAP financial measure. See “Non-GAAP and Other Financial Measures” section in this MD&A.

Subsequent to the quarter, the Board of Directors approved an increase to our 2022 return of capital plan to a minimum of $350 million or 50% of annual free cash flow[1], whichever is greater, through dividends and share repurchases. In connection with this plan, the Board of Directors approved a 30% increase to the quarterly dividend to $0.043 per share, beginning June 2022. The increased dividend is equal to approximately $40 million on an annualized basis. The remaining $310 million or greater of shareholder returns are expected to be delivered through share repurchases. We plan to repurchase the remaining 8.0 million shares under the NCIB by the end of July and renew the NCIB in August for an additional 10% of the public float (within meaning under the Toronto Stock Exchange ("TSX") rules). We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

At March 31, 2022, we were in compliance with all covenants under the Bank Credit Facilities 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. Agreements relating to our Bank Credit Facilities and the senior note purchase agreements have been filed under our SEDAR profile at www.sedar.com.

The following table lists our financial covenants at March 31, 2022:

Covenant Description		March 31, 2022
Bank Credit Facilities:	**Maximum Ratio**	
Senior debt to adjusted EBITDA	3.5x	0.7x
Total debt to adjusted EBITDA	4.0x	0.7x
Total debt to capitalization	55%	31%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.0x - 3.5x	0.7x
Senior debt to consolidated present value of total proved reserves(2)	60%	15%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	32.3x

Definitions

"Senior debt" is calculated as the sum of drawn amounts on our bank credit facilities, outstanding letters of credit and the principal amount of senior notes.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, accretion, 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, 2022 was $272.6 million and $899.8 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 $823.7 million adjustment related to our adoption of U.S. GAAP.

Footnotes

(1) 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.
(2) 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%.

Dividends

	Three months ended March 31,	
($ millions, except per share amounts)	2022	2021
Dividends(1)	$ 7.9	$ 5.6
Per weighted average share (Basic)	$ 0.033	$ 0.024

(1) Excludes changes in non-cash financing working capital. See Note 17 of the Interim Financial Statements for additional information.

During the three months ended March 31, 2022, we declared total dividends of $7.9 million or $0.033 per share, compared to $5.6 million or $0.024 per share for the same period in 2021. The aggregate amount of dividends paid to shareholders has increased compared to the same period in 2021 due to an overall 37% increase of our quarterly dividend since the first quarter of 2021, as well as an increase in common shares outstanding resulting from the Bruin equity financing in the first quarter of 2021.

Subsequent to the quarter, the Board of Directors approved a 30% increase to the quarterly dividend to $0.043 per share to be paid beginning in June 2022. We expect to fund the dividend through the free cash flow[1] generated by the business. The dividend is a part of our 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, 2022	2021
Share capital ($ millions)	$ 3,070.7	$ 3,222.8
Common shares outstanding (thousands)	241,957	256,751
Weighted average shares outstanding – basic (thousands)	242,787	244,066
Weighted average shares outstanding – diluted (thousands)	249,337	246,898

For the three months ended March 31, 2022, a total of 2,192,538 units vested pursuant to our treasury settled LTI plans, including the impact of performance multipliers (2021 – 2,014,193). In total, 1,240,000 shares were issued from treasury and $8.0 million was transferred from paid-in capital to share capital (2021 – 1,140,000; $9.4 million). We elected to cash settle the remaining units related to the required tax withholdings for the amount of $11.6 million (2021 – $3.6 million).

On August 12, 2021, we received approval from the TSX to commence a NCIB to purchase up to 10% of the public float (within the meaning under TSX rules) during a 12-month period. During the three months ended March 31, 2022, 3,134,700 common shares were repurchased and cancelled under the NCIB at an average price of $11.87 per share, for total consideration of $37.2 million. Of the amount paid, $31.3 million was charged to share capital and $5.9 million was credited to accumulated deficit. We did not have an NCIB in place during the three months ended March 31, 2021. At March 31, 2022, 9,533,390 common shares were available for repurchase under the current NCIB.

Subsequent to March 31, 2022, and up to and including May 4, 2022, we repurchased 1,494,996 common shares under the NCIB at an average price of $12.61 per common share, for total consideration of $18.9 million.

At May 4, 2022, we had 240,462,683 common shares outstanding. In addition, an aggregate of 10,278,694 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 15 to the Interim Financial Statements.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended March 31, 2022			Three months ended March 31, 2021		
($ millions, except per unit amounts)	U.S.	Canada	Total	U.S.	Canada	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	42,428	5,206	47,634	28,387	5,725	34,112
Natural gas liquids (bbls/day)	8,080	297	8,377	4,885	385	5,270
Natural gas (Mcf/day)	209,696	7,415	217,111	196,732	9,217	205,949
Total average daily production (BOE/day)	85,457	6,739	92,196	66,061	7,646	73,707
Pricing(1)						
Crude oil (per bbl)	$ 93.66	$ 75.99	$ 91.95	$ 54.91	$ 44.52	$ 53.24
Natural gas liquids (per bbl)	37.25	51.48	37.78	28.42	31.06	28.55
Natural gas (per Mcf)	4.64	3.80	4.62	2.72	3.13	2.76
Property, Plant and Equipment						
Capital and office expenditures	$ 96.6	$ 2.7	$ 99.3	$ 49.3	$ 3.8	$ 53.1
Acquisitions, including property and land	1.3	0.6	1.9	496.3	0.8	497.1
Property divestments	(6.6)	—	(6.6)	—	(4.0)	(4.0)
Netback Before Impact of Commodity Derivative Contracts(2)						
Crude oil and natural gas sales	$ 472.3	$ 40.9	$ 513.2	$ 200.9	$ 27.5	$ 228.4
Operating expenses	(71.6)	(11.6)	(83.2)	(41.7)	(9.5)	(51.2)
Transportation cost	(34.6)	(1.2)	(35.8)	(24.3)	(1.6)	(25.9)
Production taxes	(34.8)	(0.6)	(35.4)	(13.4)	(0.4)	(13.8)
Netback before impact of commodity derivative contracts	$ 331.3	$ 27.5	$ 358.8	$ 121.5	$ 16.0	$ 137.5
Other Expenses						
Commodity derivative instruments loss	$ —	$ 206.8	$ 206.8	$ —	$ 56.3	$ 56.3
Asset impairment	—	—	—	3.4	—	3.4
General and administrative expense(3)	7.6	10.0	17.6	7.6	5.2	12.8
Current income tax expense	5.0	—	5.0	—	—	—

(1) Before transportation costs and the effects of commodity derivative instruments.
(2) This financial measure is a non-GAAP financial measure. See "Non-GAAP and Other Financial Measures" section in this MD&A.
(3) Includes share-based compensation.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Crude Oil and Natural Gas Sales	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2022				
First Quarter	$ 513.2	$ 33.2	$ 0.14	$ 0.13
Total 2022	$ 513.2	$ 33.2	$ 0.14	$ 0.13
2021				
Fourth Quarter	$ 499.7	$ 176.9	$ 0.71	$ 0.68
Third Quarter	421.1	98.1	0.38	0.38
Second Quarter	333.4	(50.9)	(0.20)	(0.20)
First Quarter	228.4	10.3	0.04	0.04
Total 2021	$ 1,482.6	$ 234.4	$ 0.93	$ 0.90
2020				
Fourth Quarter	$ 150.2	$ (161.6)	$ (0.73)	$ (0.73)
Third Quarter	144.2	(84.4)	(0.38)	(0.38)
Second Quarter	88.9	(444.6)	(2.00)	(2.00)
First Quarter	170.4	(2.8)	(0.01)	(0.01)
Total 2020	$ 553.7	$ (693.4)	$ (3.12)	$ (3.12)

Crude oil and natural gas sales increased to $513.2 million during the first quarter of 2022, compared to $499.7 million during the fourth quarter of 2021. The increase in crude oil and natural gas sales was a result of improved realized pricing during the first quarter of 2022, when compared to the fourth quarter of 2021. We reported net income of $33.2 million during the first quarter of 2022 compared to net income of $176.9 million during the fourth quarter of 2021. The decrease was primarily due to a $206.8 million loss recorded on commodity derivative instruments as a result of higher commodity prices.

Crude oil and natural gas sales increased in 2021 compared to 2020 due to higher production from the Bruin and Dunn County acquisitions and higher realized prices. We reported a net loss in 2020 due to PP&E impairments totaling $751.7 million and a goodwill impairment of $149.2 million on our U.S. reporting unit recorded in the twelve months ended December 31, 2020.

RISK FACTORS AND RISK MANAGEMENT

Risks relating to the Impact of the Ukraine and Russia conflict

The current conflict between Ukraine and Russia and the international response has, and may continue to have, potential wide-ranging consequences for global market volatility and economic conditions, including oil and gas prices. Certain countries including Canada, the United States, Australia and certain European countries have imposed strict financial and trade sanctions against Russia, which may have continued far-reaching effects on the global economy, energy and commodity prices and food security and crop nutrient supply and prices. The short-, medium- and long-term implications of the conflict in Ukraine are difficult to predict with any degree of certainty at this time. Depending on the extent, duration, and severity of the conflict, it may have the effect of heightening many of the other risks described in our Annual MD&A and our Annual Information Form for the year ended December 31, 2021, including, without limitation, risks relating to global market volatility and economic conditions; cybersecurity threats; oil and gas prices; inflationary pressures, interest rates and costs of capital; and supply chains and cost-effective and timely transportation.

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, 2021.

2022 GUIDANCE[(1)]

We are revising our annual capital spending guidance for 2022 to between $400 to $440 million, from a range of $370 to $430 million.

We are revising our average annual production guidance for 2022 to 96,000 to 101,000 BOE/day, including 58,500 to 62,500 bbls/day in crude oil and natural gas liquids from 95,500 to 100,500 BOE/day including 58,000 to 62,000 bbls/day in crude oil and natural gas liquids.

We are revising our expected operating expenses guidance for 2022 to average between $9.75/BOE to $10.50/BOE from $9.50/BOE to $10.50/BOE.

In 2022, we expect our realized Bakken oil price to be at par with WTI, compared to $0.50/bbl below WTI, previously.

As a result of the higher commodity price environment, we are increasing our current tax guidance from $10 million to $20 – $30 million (2% – 3% of adjusted funds flow before tax) for 2022 assuming WTI of $85.00/bbl and NYMEX of $5.00/Mcf.

Summary of 2022 Annual Expectations	Target Annual Results
Capital spending ($ millions)	$400 - $440 (from $370 - $430)
Average annual production (BOE/day)	96,000 - 101,000 (from 95,500 - 100,500)
Average annual crude oil and natural gas liquids production (bbls/day)	58,500 - 62,500 (from 58,000 - 62,000)
Average production tax rate (% of net sales, before transportation)	7%
Operating expenses (per BOE)	$9.75 - $10.50 (from $9.50 - $10.50)
Transportation costs (per BOE)	$4.15
Cash G&A expenses (per BOE)	$1.25
Current tax expense	$20 - $30 million (2% - 3% of adjusted funds flow before tax) (from $10 million)

Differential/Basis Outlook[(2)]	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	$0/bbl (from $(0.50)/bbl)
Average Marcellus natural gas differential (compared to NYMEX natural gas)	$(0.75)/Mcf

(1) Guidance is based on the continued operation of DAPL and has not been adjusted to reflect the potential divestment of our Canadian assets as announced on February 2, 2022.
(2) Excludes transportation costs.

NON-GAAP MEASURES

This MD&A includes references to certain non-GAAP financial measures and non-GAAP ratios used by the Company to evaluate its financial performance, financial position or cash flow. Non-GAAP financial measures are financial measures disclosed by a company that (a) depict historical or expected future financial performance, financial position or cash flow of a company, (b) with respect to their composition, exclude amounts that are included in, or include amounts that are excluded from, the composition of the most directly comparable financial measure disclosed in the primary financial statements of the company, (c) are not disclosed in the financial statements of the company and (d) are not a ratio, fraction, percentage or similar representation. Non-GAAP ratios are financial measures disclosed by a company that are in the form of a ratio, fraction, percentage or similar representation that has a non-GAAP financial measure as one or more of its components, and that are not disclosed in the financial statements of the company.

These non-GAAP financial measures and non-GAAP ratios do not have standardized meanings or definitions as prescribed by U.S. GAAP and may not be comparable with the calculation of similar financial measures by other entities. For each measure, we have indicated the composition of the measure, identified the GAAP equivalency to the extent one exists, provided comparative detail where appropriate, indicated the reconciliation of the measure to the mostly directly comparable GAAP financial measure and provided details on the usefulness of the measure for the reader. These non-GAAP financial measures and non-GAAP ratios should not be considered as a substitute for, or superior to, measures of financial performance prepared in accordance with GAAP.

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

	Three months ended March 31,	
($ millions)	2022	2021
Cash flow from/(used in) operating activities	**$ 196.0**	**$ 28.7**
Asset retirement obligation settlements	8.8	5.6
Changes in non-cash operating working capital	57.1	66.6
Adjusted funds flow	**$ 261.9**	**$ 100.9**

"Adjusted net income" is used by Enerplus and is useful to investors and securities analysts in evaluating the financial performance of the company by adjusting for certain unrealized items and other items that the company considers appropriate to adjust given their irregular nature. The most directly comparable GAAP measure is net income/(loss). No income tax rate adjustment on deferred taxes or goodwill impairment, or valuation allowance on deferred taxes were recorded for the three months ended March 31, 2022 and 2021. The calculation follows:

	Three months ended March 31,	
($ millions)	2022	2021
Net income/(loss)	**$ 33.2**	**$ 10.3**
Unrealized non-cash derivative instrument (gain)/loss	133.3	40.4
Asset impairment	—	3.4
Other expense related to investing activities	13.1	—
Unrealized non-cash foreign exchange (gain)/loss	1.2	0.2
Tax effect on above items	(35.0)	(10.4)
Adjusted net income/(loss)	**$ 145.8**	**$ 43.9**

"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. There is no directly comparable related GAAP equivalent for this measure. Adjusted funds flow is reconciled above.

	Three months ended March 31,	
($ millions)	2022	2021
Adjusted funds flow	$ 261.9	$ 100.9
Capital spending	(99.0)	(51.8)
Free cash flow	**$ 162.9**	**$ 49.1**

“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 net debt divided by a trailing twelve months of adjusted funds flow. There is no directly comparable GAAP equivalent for this measure, and it is not equivalent to any of our debt covenants. The calculation follows:

	Three months ended March 31,	
($ millions)	**2022**	**2021**
Net debt	$ 572.3	$ 632.2
Trailing adjusted funds flow	873.5	282.5
Net debt to adjusted funds flow ratio	**0.7x**	**2.2x**

“Netback before impact of commodity derivative contracts” and **“Netback after impact of commodity derivative contracts”** is used by Enerplus and is useful to investors and securities analysts, in evaluating operating performance of our crude oil and natural gas assets, both before and after consideration of our realized gain/(loss) on commodity derivative instruments. A direct GAAP equivalent does not exist for these measures, although a reconciliation is provided as follows:

	Three months ended March 31,	
($ millions)	**2022**	**2021**
Crude oil and natural gas sales	$ 513.2	$ 228.4
Less:		
Operating expenses	(83.2)	(51.2)
Transportation costs	(35.8)	(25.9)
Production taxes	(35.4)	(13.8)
Netback before impact of commodity derivative contracts	**$ 358.8**	**$ 137.5**
Net realized gain/(loss) on derivative instruments	(73.1)	(15.4)
Netback after impact of commodity derivative contracts	**$ 285.7**	**$ 122.1**

“Reinvestment rate” is used by Enerplus and is useful to investors and securities analysts in analyzing the reinvestment of capital spending by comparing the amount of our capitals spending as compared to adjusted funds flow (as a percentage). There is no directly comparable GAAP measure. The calculation follows:

	Three months ended March 31,	
($ millions)	**2022**	**2021**
Capital spending	$ 99.0	$ 51.8
Adjusted funds flow	261.9	100.9
Reinvestment rate (%)	**38%**	**51%**

Other Financial Measures

CAPITAL MANAGEMENT MEASURES

Capital management measures are financial measures disclosed by a company that (a) are intended to enable an individual to evaluate a company’s objectives, policies and processes for managing the company's capital, (b) are not a component of a line item disclosed in the primary financial statements of the company, (c) are disclosed in the notes to the financial statements of the company, and (d) are not disclosed in the primary financial statements of the company. The following section provides an explanation of the composition of those capital management measures if not previously provided:

“Net Debt” is calculated as current and long-term debt associated with senior notes plus any outstanding Bank Credit Facilities balances, less cash and cash equivalents. “Net debt” is useful to investors and securities analysts in analyzing financial liquidity and Enerplus considers net debt to be a key measure of capital management. For further details, see Note 8 to the Interim Financial Statements.

SUPPLEMENTARY FINANCIAL MEASURES

Supplementary financial measures are financial measures disclosed by a company that (a) are, or are intended to be, disclosed on a periodic basis to depict the historical or expected future financial performance, financial position or cash flow of a company, (b) are not disclosed in the financial statements of the company, (c) are not non-GAAP financial measures, and (d) are not non-GAAP ratios. The following section provides an explanation of the composition of those supplementary financial measures if not previously provided:

“Capital spending” Capital and office expenditures, excluding other capital assets/office capital and property and land acquisitions and divestments.

“Cash general and administrative expenses” or **“Cash G&A expenses”** General and administrative expenses that are settled through cash payout, as opposed to expenses that relate to accretion or other non-cash allocations that are recorded as part of general and administrative expenses.

“Cash share-based compensation” or **“Cash SBC expenses”** Share-based compensation that is settled by way of cash payout, as opposed to equity settled.

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, at March 31, 2022, 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, 2022 and ended March 31, 2022 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 production volumes in 2022 and 2022 production guidance; 2022 capital spending guidance and expected capital spending levels in 2022; expectations regarding payment of dividends and Enerplus' share repurchase program, including timing and amounts thereof and funding dividends and the share repurchase program from free cash flow; expectations regarding free cash flow generation and long-term capital spending reinvestment rates; expected operating strategy in 2022; 2022 average production volumes and the anticipated production mix; the proportion of our anticipated crude oil and natural gas liquids production that is hedged and the expected effectiveness of such hedges in protecting our cash flow from operating activities and adjusted funds flow; oil and natural gas prices and differentials and expectations regarding the market environment and our commodity risk management program in 2022; updated and existing 2022 Bakken and Marcellus differential guidance; expectations regarding realized oil and natural gas prices; expected operating, transportation and cash G&A expenses and production taxes and 2022 guidance with respect thereto; 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; deferred income taxes, tax pools and the time at which cash taxes may be paid; 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, working capital requirements and deficits and senior note repayments; expectations regarding payment of increased dividends; expectations regarding our ability to comply with or renegotiate debt covenants under the Bank Credit Facilities and outstanding senior notes; our future acquisitions and dispositions, including the divestment process for our Canadian assets in 2022 and the completion and timing thereof; and expectations regarding renewal of our NCIB, including timing and size thereof.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; the continued operation of DAPL; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current and anticipated commodity prices, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions, the impact of inflation, weather conditions, storage fundamentals and 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 ability to fund increased dividend payments and the share purchase program from free cash flow as expected and discussed in this MD&A; our ability to comply with our debt covenants; the availability of third party services; expected transportation costs; the extent of our liabilities; the rates used to calculate the amount of our future abandonment and reclamation costs and asset retirement obligations; factors used to assess the realizability of our deferred income tax assets; and the availability of technology and *process to achieve environmental targets. In addition, our 2022 guidance described in this MD&A is based on: a WTI price of $85.00/bbl, a NYMEX price of $5.00/Mcf, a Bakken crude oil price at par with WTI, a Marcellus natural gas price differential of $0.75/Mcf below NYMEX and a CDN/USD exchange rate of 0.79. 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: continued instability, or further deterioration, in global economic and market environment, including from COVID-19, inflation and/or the Ukraine/Russia conflict and heightened geopolitical risks; decreases in commodity prices 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; legal proceedings or other events inhibiting or preventing operation of 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; risks associated with the realization of our deferred income tax assets; 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 Facilities and/or 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 at December 31, 2021).

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.