enerPLUS

third quarter report

nine months ended September 30, 2022

SELECTED FINANCIAL RESULTS	Three months ended September 30,		Nine months ended September 30,	
	2022	2021	2022	2021
Financial (US$, thousands, except ratios)				
Net Income/(Loss)	$ 305,945	$ 98,112	$ 583,594	$ 57,528
Adjusted Net Income[1]	207,913	87,467	525,992	186,004
Cash Flow from Operating Activities	409,946	182,177	856,798	321,305
Adjusted Funds Flow	355,622	203,131	914,910	453,956
Dividends to Shareholders - Declared	11,516	7,929	29,374	22,651
Net Debt	391,059	826,282	391,059	826,282
Capital Spending	114,459	63,613	346,357	221,289
Property and Land Acquisitions	16,252	3,079	19,662	832,404
Property Divestments	4,214	(216)	19,386	3,782
Net Debt to Adjusted Funds Flow Ratio	0.3x	1.6x	0.3x	1.6x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ 1.32	$ 0.38	$ 2.47	$ 0.22
Net Income/(Loss) - Diluted	1.28	0.38	2.40	0.22
Weighted Average Number of Shares Outstanding (000's) - Basic	231,565	256,345	237,835	252,432
Weighted Average Number of Shares Outstanding (000's) - Diluted	239,136	260,831	245,403	256,900
Selected Financial Results per BOE[2][3]				
Crude Oil & Natural Gas Sales[4]	$ 66.90	$ 46.10	$ 67.38	$ 40.61
Commodity Derivative Instruments	(8.92)	(5.39)	(11.19)	(3.95)
Operating Expenses	(10.47)	(9.76)	(10.10)	(8.78)
Transportation Costs	(4.16)	(3.56)	(4.29)	(3.63)
Production Taxes	(4.86)	(3.33)	(4.76)	(2.86)
General and Administrative Expenses	(1.10)	(0.94)	(1.18)	(1.15)
Cash Share-Based Compensation	(0.12)	(0.09)	(0.13)	(0.20)
Interest, Foreign Exchange and Other Expenses	(0.61)	(0.89)	(0.64)	(1.18)
Current Income Tax Recovery/(Expense)	(0.80)	0.10	(0.93)	(0.10)
Adjusted Funds Flow	$ 35.86	$ 22.24	$ 34.16	$ 18.76

SELECTED OPERATING RESULTS	Three months ended September 30,		Nine months ended September 30,	
	2022	2021	2022	2021
Average Daily Production[3]				
Crude Oil (bbls/day)	57,482	54,578	51,146	46,188
Natural Gas Liquids (bbls/day)	10,900	8,492	9,319	7,246
Natural Gas (Mcf/day)	236,558	217,253	225,845	211,299
Total (BOE/day)	107,808	99,279	98,106	88,651
% Crude Oil and Natural Gas Liquids	63%	64%	62%	60%
Average Selling Price[3][4]				
Crude Oil (per bbl)	$ 92.48	$ 67.22	$ 97.44	$ 62.12
Natural Gas Liquids (per bbl)	32.04	29.91	34.13	25.40
Natural Gas (per Mcf)	6.53	3.00	5.79	2.58
Net Wells Drilled	9.0	9.0	40.2	14.0

(1) This financial measure is a non-GAAP financial measure and may not be directly comparable to similar measures presented by other entities. See "Non-GAAP Measures" section in this MD&A.
(2) Non-cash amounts have been excluded.
(3) Based on Net production volumes. See "Basis of Presentation" section in the following MD&A.
(4) Before transportation costs and commodity derivative instruments.

Average Benchmark Pricing	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
WTI Crude Oil ($/bbl)	$ 91.56	$ 70.56	$ 98.09	$ 64.82
Brent (ICE) Crude Oil ($/bbl)	97.81	73.23	102.33	67.78
Propane – Conway ($/bbl)	44.73	49.01	49.98	40.87
NYMEX Natural Gas – Last Day ($/Mcf)	8.20	4.01	6.77	3.18
CDN/US Average Exchange Rate	0.77	0.79	0.78	0.80

Share Trading Summary For the three months ended September 30, 2022	U.S.[1] – ERF (US$)	CDN[2] – ERF (CDN$)
High	$ 16.48	$ 21.43
Low	$ 11.00	$ 14.47
Close	$ 14.17	$ 19.56

(1) NYSE and other U.S. trading data combined.
(2) TSX and other Canadian trading data combined.

2022 Dividends Declared per Share	US$	CDN$[1]
First Quarter Total	$ 0.033	$ 0.042
Second Quarter Total	$ 0.043	$ 0.056
Third Quarter Total	$ 0.050	$ 0.066
Total	$ 0.126	$ 0.164

(1) CDN$ dividends converted at the relevant foreign exchange rate on the payment date.

NEWS RELEASE

HIGHLIGHTS

- Third quarter total production was 107,808 BOE per day (up 15% from the prior quarter) and liquids production was 68,382 barrels per day (up 20% from the prior quarter)
- Adjusted funds flow was $355.6 million in the third quarter, which exceeded capital spending of $114.5 million, generating free cash flow[1] of $241.1 million
- Total return of capital to shareholders during the third quarter was $123.3 million, comprising share repurchases of $111.8 million and dividends of $11.5 million
- Increased the quarterly dividend by 10% to $0.055 per share (from $0.05 per share)
- 2022 liquids production guidance was increased by 1,000 barrels per day at the midpoint due to continued strong operational performance; annual liquids production growth now tracking approximately 10%
- 2022 capital spending guidance was set to $430 million (from the previous range of $400 – $440 million)
- Fourth quarter production guidance is 105,000 to 110,000 BOE per day, including liquids production of 64,000 to 68,000 barrels per day

“Our operating momentum continued through the third quarter with liquids production increasing 20% quarter-over-quarter and strong volumes expected through the end of the year,” said Ian C. Dundas, President and CEO. “This performance has driven another positive production guidance update while annual capital spending is forecast inside our previously stated range. The result of this execution has been robust free cash flow generation which has allowed us to reduce our net debt by almost 40% and return over $270 million to shareholders through the first nine months of 2022. We remain well positioned to continue with these initiatives in the fourth quarter and into 2023.”

THIRD QUARTER SUMMARY

Production in the third quarter of 2022 was 107,808 BOE per day, an increase of 15% compared to the prior quarter and 9% higher than the same period a year ago. Crude oil and natural gas liquids production in the third quarter of 2022 was 68,382 barrels per day, an increase of 20% compared to the prior quarter and 8% higher than the same period a year ago. Production increased from the previous quarter and prior year period primarily due to the Company’s development activity in North Dakota.

Enerplus reported third quarter 2022 net income of $305.9 million, or $1.28 per share (diluted), compared to net income of $98.1 million, or $0.38 per share (diluted), in the same period in 2021. Adjusted net income[1] for the third quarter of 2022 was $207.9 million, or $0.87 per share (diluted), compared to $87.5 million, or $0.34 per share (diluted), during the same period in 2021. Net income and adjusted net income were higher compared to the prior year period primarily due to higher realized commodity prices and production during the third quarter of 2022.

Enerplus’ third quarter 2022 realized Bakken crude oil price differential was $2.41 per barrel above WTI, compared to $2.26 per barrel below WTI in the third quarter of 2021. Bakken crude oil prices continued to trade at premiums relative to WTI due to excess pipeline capacity in the region and strong physical 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, Enerplus expects its 2022 realized average Bakken crude oil price differential to be $1.25 per barrel above WTI, compared to $1.00 per barrel above WTI, previously.

The Company’s realized Marcellus natural gas price differential widened to $0.99 per Mcf below NYMEX during the third quarter of 2022, compared to $0.45 per Mcf below NYMEX in the third quarter of 2021. The Company’s realized natural gas price was $6.53 per Mcf in the third quarter of 2022, an increase from $3.00 per Mcf in the same period in 2021 due to the increase in NYMEX natural gas prices in 2022. Enerplus continues to expect its full-year 2022 Marcellus natural gas price differential to average $0.75 per Mcf below NYMEX.

In the third quarter of 2022, Enerplus’ operating expenses were $10.47 per BOE, compared to $9.76 per BOE during the third quarter of 2021. The Company continues to expect full-year 2022 operating expenses to average $10.00 per BOE.

Capital spending totaled $114.5 million in the third quarter of 2022. The Company ended the third quarter of 2022 with total debt of $433.2 million and cash of $42.2 million.

[1] This is a non-GAAP financial measure. Refer to "Non-GAAP and Other Financial Measures" section for more information.

During the third quarter of 2022, Enerplus announced its intention to increase its expected 2022 return of capital to at least 60% of free cash flow commencing in the second half of 2022 and continuing through 2023, an increase from 50% of free cash flow in the first half of 2022. Enerplus also previously announced an increase to the expected minimum return of capital level to $425 million for 2022. In the third quarter, Enerplus paid $11.5 million in dividends and repurchased 7.9 million shares under its normal course issuer bid ("NCIB") at an average price of $14.13 per share, for total consideration of $111.8 million.

During the nine months ended September 30, 2022, a total of $271.3 million was returned to shareholders through dividends and share repurchases.

Subsequent to September 30, 2022 and up to November 2, 2022, Enerplus repurchased 2.7 million shares under its NCIB at an average price of $16.00 per share, for total consideration of $43.7 million. Enerplus has also increased its quarterly dividend by 10% to $0.055 per share payable on December 15, 2022.

ASSET DETAIL

North Dakota production averaged 73,188 BOE per day during the third quarter of 2022, an increase of 25% compared to the prior quarter and 16% compared to the same period a year ago. Enerplus drilled eight gross operated wells (83% working interest) during the third quarter and brought eight operated wells (96% working interest) on production.

Marcellus production averaged 165 MMcf per day during the third quarter of 2022, an increase of 7% compared to the same period in 2021 and 2% lower than the prior quarter.

2022 GUIDANCE UPDATE

Capital spending guidance in 2022 has been updated to $430 million from the prior range of $400 to $440 million.

Annual production guidance has been revised to 99,750 to 101,000 BOE per day from the prior range of 97,500 to 101,500 BOE per day, representing an increase of 875 BOE per day at the midpoint. Annual liquids production guidance has been revised to 61,500 to 62,500 barrels per day from the prior range of 59,500 to 62,500 barrels per day, representing an increase of 1,000 barrels per day at the midpoint.

Fourth quarter volumes are expected to remain strong despite the two announced divestments of the Company's Canadian assets, one of which closed on October 31, 2022 with the other expected to close in December 2022. Enerplus is providing fourth quarter 2022 production guidance of 105,000 to 110,000 BOE per day, including liquids production of 64,000 to 68,000 barrels per day.

Enerplus' 2022 Bakken crude oil price differential guidance has been strengthened to $1.25 per barrel above WTI, from $1.00 per barrel above WTI previously.

A summary of Enerplus' updated 2022 guidance is provided in the tables below and includes the impact of the two announced Canadian asset divestments.

2022 Guidance Summary

	Updated Guidance	Previous Guidance
Capital spending	$430 million	$400 – 440 million
Average total production	99,750 – 101,000 BOE/day	97,500 – 101,500 BOE/day
Average liquids production	61,500 – 62,500 bbls/day	59,500 – 62,500 bbls/day
Fourth quarter total production	105,000 – 110,000 BOE/day	N/A
Fourth quarter liquids production	64,000 – 68,000 bbls/day	N/A
Average production tax rate (% of net sales, before transportation)	7% (No change)	7%
Operating expense	$10.00/BOE (No change)	$10.00/BOE
Transportation expense	$4.25/BOE (No change)	$4.25/BOE
Cash G&A expense	$1.20/BOE (No change)	$1.20/BOE
Current tax expense	2-3% of adjusted funds flow before tax (No change)	2-3% of adjusted funds flow before tax

2022 Differential/Basis Outlook[1]

	Updated Guidance	Previous Guidance
U.S. Bakken crude oil differential (compared to WTI crude oil)	$+1.25/bbl	$+1.00/bbl
Marcellus natural gas price differential (compared to NYMEX natural gas)	$(0.75)/Mcf (No change)	$(0.75)/Mcf

(1) Excluding transportation costs.

Q3 2022 CONFERENCE CALL DETAILS

A conference call hosted by Ian C. Dundas, President and CEO will be held at 9:00 AM MT (11:00 AM ET) on November 4, 2022, to discuss these results. Details of the conference call are as follows:

Date:	Friday, November 4, 2022
Time:	9:00 AM MT (11:00 AM ET)
Dial-In:	587-880-2171 (Alberta) 1-888-390-0546 (Toll Free)
Conference ID:	58265396
Audiocast:	https://app.webinar.net/wraEPb2PVB9

To ensure timely participation in the conference call, callers are encouraged to join 15 minutes prior to the start time to register for the event. A telephone replay will be available for 30 days following the conference call and can be accessed at the following numbers:

Replay Dial-In:	1-888-390-0541 (Toll Free)
Replay Passcode:	265396 #

PRICE RISK MANAGEMENT

The following is a summary of Enerplus' financial commodity hedging contracts at November 3, 2022.

	WTI Crude Oil ($/bbl)[1][2][3]			NYMEX Natural Gas ($/Mcf)[2]		
	Oct 1, 2022 – Dec 31, 2022	**Jan 1, 2023 – Jun 30, 2023**	**Jul 1, 2023 – Dec 31, 2023**	**Oct 1, 2022 – Oct 31, 2022**	**Nov 1, 2022 – Mar 31, 2023**	**Apr 1, 2023 – Oct 31, 2023**
Swaps						
Volume (Mcf/day)	–	–	–	40,000	–	–
Volume (bbls/day)	–	10,000	10,000	–	–	–
Swaps	–	–	–	$ 3.40	–	–
Brent - WTI Spread	–	$ 5.47	$ 5.47	–	–	–
3 Way Collars						
Volume (bbls/day)	17,000	15,000	5,000	–	–	–
Sold Puts	$ 40.00	$ 61.67	$ 65.00	–	–	–
Purchased Puts	$ 50.00	$ 79.33	$ 85.00	–	–	–
Sold Calls	$ 57.91	$ 114.31	$ 128.16	–	–	–
Collars						
Volume (Mcf/day)	–	–	–	60,000	120,000	50,000
Volume (bbls/day)	–	2,000	2,000	–	–	–
Purchased Puts	–	$ 5.00	$ 5.00	$ 3.77	$ 6.27	$ 4.05
Sold Calls	–	$ 75.00	$ 75.00	$ 4.50	$ 18.17	$ 7.00

(1) The total average deferred premium spent on our outstanding crude oil contracts is $1.50/bbl from October 1, 2022 – December 31, 2022 and $1.25/bbl from January 1, 2023 – December 31, 2023.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Upon closing of the acquisition of Bruin E&P Holdco, LLC (the "Bruin Acquisition"), Bruin E&P Holdco, LLC's outstanding crude oil contracts were recorded at a fair value liability of $76.4 million. At September 30, 2022, the remaining liability was $4.7 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.

THIRD QUARTER 2022 PRODUCTION AND OPERATIONAL SUMMARY TABLES

Summary of Average Daily Production[1]

	Three months ended September 30, 2022					Nine months ended September 30, 2022				
	Williston Basin	Marcellus	Canadian Water-floods	Other[2]	Total	Williston Basin	Marcellus	Canadian Water-floods	Other[2]	Total
Tight oil (bbl/d)	52,014	—	—	779	**52,793**	45,376	—	—	817	**46,194**
Light & medium oil (bbl/d)	—	—	2,006	32	**2,038**	—	—	2,069	28	**2,097**
Heavy oil (bbl/d)	—	—	2,629	22	**2,651**	—	—	2,841	14	**2,855**
Total crude oil (bbl/d)	**52,014**	**—**	**4,635**	**833**	**57,482**	**45,376**	**—**	**4,911**	**859**	**51,146**
Natural gas liquids (bbl/d)	**10,511**	**—**	**102**	**287**	**10,900**	**8,916**	**—**	**92**	**311**	**9,319**
Shale gas (Mcf/d)	63,976	164,731	—	941	**229,649**	52,904	164,843	—	959	**218,706**
Conventional natural gas (Mcf/d)	—	—	1,375	5,534	**6,909**	—	—	1,405	5,734	**7,139**
Total natural gas (Mcf/d)	**63,976**	**164,731**	**1,375**	**6,475**	**236,558**	**52,904**	**164,843**	**1,405**	**6,693**	**225,845**
Total production (BOE/d)	**73,188**	**27,455**	**4,966**	**2,199**	**107,808**	**63,110**	**27,474**	**5,237**	**2,285**	**98,106**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and other properties in Canada.

Summary of Wells Drilled[1]

	Three months ended September 30, 2022				Nine months ended September 30, 2022			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	8	6.6	6	0.2	35	30.1	34	4.6
Marcellus	—	—	23	2.2	—	—	60	5.1
Canadian Waterfloods	—	—	—	—	—	—	—	—
Other[2]	—	—	—	—	—	—	15	0.4
Total	**8**	**6.6**	**29**	**2.4**	**35**	**30.1**	**109**	**10.1**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and other properties in Canada.

Summary of Wells Brought On-Stream[1]

	Three months ended September 30, 2022				Nine months ended September 30, 2022			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	8	7.7	25	4.1	34	30.7	30	4.4
Marcellus	—	—	10	1.2	—	—	58	4.1
Canadian Waterfloods	—	—	—	—	—	—	—	—
Other[2]	—	—	—	—	—	—	—	—
Total	**8**	**7.7**	**35**	**5.2**	**34**	**30.7**	**88**	**8.5**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and other properties in Canada.

Currency and Accounting Principles

All amounts in this news release are stated in U.S. dollars unless otherwise specified. All financial information in this news release has been prepared and presented in accordance with U.S. GAAP, except as noted below under "Non-GAAP and Other Financial Measures".

Barrels of Oil Equivalent

This news release contains references to "BOE" (barrels of oil equivalent), "MBOE" (one thousand barrels of oil equivalent), and "MMBOE" (one million barrels of oil equivalent). Enerplus has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.

Basis of Presentation

All production volumes presented in this news release are reported on a "net" basis (the Company's working interest share after deduction of royalty obligations, plus the Company's royalty interests), unless expressly indicated that it is being presented on a "gross" basis. Previously, the Company presented production volumes on a "company interest" basis, which was calculated as its working interest share before deduction of royalties plus the Company's royalty interests. With these changes, production volumes presented by the Company on a "net" basis are expected to be lower than those presented historically.

All references to "liquids" in this news release 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 news release include conventional natural gas and shale gas on a combined basis.

Readers are urged to review the 2021 annual MD&A and financial statements filed on SEDAR and as part of our Form 40-F on EDGAR concurrently with this news release for more complete disclosure on our operations.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release 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 news release contains forward-looking information pertaining to the following: Enerplus' return of capital plans, including expectations regarding the payment of dividends and the source of funds and timing related thereto; expectations regarding Enerplus' share repurchase program and the funding of such share repurchases from free cash flow; the sale of Enerplus' Canadian assets and the expected timing and impact thereof on Enerplus' operations, and financial results; updated 2022 production guidance; capital spending guidance and expected capital spending levels in 2022 and future years; expectations regarding free cash flow generation and reinvestment rates; reduction of net debt; 2022 average production volumes 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 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; and expected operating, transportation and cash G&A expenses and tax expenses and updated 2022 guidance with respect thereto.

The forward-looking information contained in this news release reflects several material factors and expectations and assumptions of Enerplus including, without limitation: the ability to fund our return of capital plans, including both dividends and the share repurchase program, from free cash flow as expected; that our common share trading price will be at levels, and that there will be no other alternatives, that, in each case, make share repurchases an appropriate and best strategic use of our free cash flows; that we will conduct our operations and achieve results of operations as anticipated; that Enerplus will realize the expected impact and proceeds of the sale of assets in Canada; the continued operation of the Dakota Access Pipeline; 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 execute our share *repurchase program as currently expected and in compliance with applicable Canadian and US rules; our ability to comply with our debt covenants; the availability of third party services; expected transportation expenses; the extent of our liabilities; and the availability of technology and process to achieve environmental targets. In addition, our 2022 guidance described in this news release is based on rest of year commodity prices of: $85.00/bbl WTI and $6.00/Mcf NYMEX and a CDN/USD exchange rate of 0.72. 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 increased uncertainty.*

The forward-looking information included in this news release 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 proceeds or benefits of the sale of assets in Canada; continued instability, or further deterioration, in global economic and market environment, including from COVID-19 or similar events, 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; including global energy demand; volatility in our common share trading price and free cash flow that could impact our planned share repurchases and dividend levels; unanticipated operating results, results from our capital spending activities or production declines; legal proceedings or other events inhibiting or preventing operation of the Dakota Access Pipeline; 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 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; failure to complete the recently announced sale of substantially all of Enerplus' remaining Canadian assets; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our 2022 Interim MD&As, our annual information form for the year ended December 31, 2021, our 2021 annual MD&A and Form 40-F as at December 31, 2021) which are available at www.sedar.com, www.sec.gov and through Enerplus' website at www.enerplus.com.

The forward-looking information contained in this news release speaks only as of the date of this news release. Enerplus does not undertake any obligation to publicly update or revise any forward-looking information contained herein, except as required by applicable laws. Any forward-looking information contained herein are expressly qualified by this cautionary statement.

NON-GAAP AND OTHER FINANCIAL MEASURES

Non-GAAP Financial Measures

This news release 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 net income/(loss)” and “**Adjusted net income/(loss) per share (diluted)**” are used by Enerplus and are 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 adjustments or valuation allowances on deferred taxes were recorded for the three months ended September 30, 2022 and 2021. Adjusted net income per share is calculated using adjusted net income, as reconciled below, divided by the number of common shares outstanding on a diluted basis during the applicable period as determined in accordance with U.S. GAAP. The calculation follows:

	Three months ended September 30,	
($ millions)	2022	2021
Net income/(loss)	**$ 305.9**	**$ (98.1)**
Unrealized derivative instrument (gain)/loss	(145.5)	8.0
Asset impairment	—	—
Other expense related to investing activities	—	—
Unrealized foreign exchange (gain)/loss	17.0	(14.2)
Tax effect on above items	30.5	0.2
Other income related to investing activities	—	(4.6)
Adjusted net income/(loss)	**$ 207.9**	**$ 87.5**
Adjusted net income/(loss) per share (diluted)	**$ 0.87**	**$ 0.34**

“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. The most directly comparable GAAP measure is cash flow from operating activities

	Three months ended September 30,	
($ millions)	2022	2021
Cash flow from/(used in) operating activities	$ 409.9	$ 182.2
Asset retirement obligation settlements	1.6	1.7
Changes in non-cash operating working capital	(55.9)	19.3
Adjusted funds flow	**$ 355.6**	**$ 203.2**
Capital spending	(114.5)	(63.6)
Free cash flow	**$ 241.1**	**$ 139.6**

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:

“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.

“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.

“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.

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.

"Reinvestment rate" Comparing the amount of our capital spending as compared to adjusted funds flow (as a percentage).

Electronic copies of Enerplus' 2022 interim reports and annual 2021 Financial Statements and associated MD&As, along with other public information including investor presentations, are or will be available on the Company's website at www.enerplus.com. For further information, please contact Investor Relations at 1-800-319-6462 or email investorrelations@enerplus.com.

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

The following discussion and analysis of financial results is dated November 3, 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 and nine months ended September 30, 2022 and 2021 (the "Interim Financial Statements") and notes thereto;
- 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. Unless otherwise stated, all dollar amounts are presented in U.S. dollars. 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. All prior period crude oil and natural gas sales have been restated to be presented net of royalties. 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 third quarter of 2022 averaged 107,808 BOE/day, an increase of 15% compared to average production of 94,142 BOE/day in the second quarter of 2022 with crude oil and natural gas liquids production increasing by 20% over the same period. The increase in production was due to strong well performance during the quarter. As a result, we are increasing our average annual production guidance for 2022 to 99,750 BOE/day to 101,000 BOE/day, including 61,500 bbls/day to 62,500 bbls/day of crude oil and natural gas liquids, from 97,500 BOE/day to 101,500 BOE/day, including 59,500 bbls/day to 62,500 bbls/day of crude oil and natural gas liquids. For the fourth quarter of 2022, we expect average production of 105,000 BOE/day to 110,000 BOE/day, including 64,000 bbls/day to 68,000 bbls/day of crude oil and natural gas liquids. The updated production guidance includes the impact of the two previously announced Canadian asset divestments.

During the nine months ended September 30, 2022, a total of $271.3 million was returned to shareholders through share repurchases and dividends. During the third quarter of 2022, we announced our intention to increase our expected 2022 return of capital to at least 60% of free cash flow[1] commencing in the second half of 2022 and continuing through 2023, an increase from 50% of free cash flow in the first half of 2022. We also previously announced an increase to the expected minimum return of capital level to $425 million for 2022. Subsequent to the quarter, the Board of Directors approved a 10% increase to the quarterly dividend to $0.055 per share, from $0.050 per share, beginning December 2022. We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

On July 28, 2022, the Company announced it had entered into a definitive agreement to sell certain Canadian assets located in Alberta for total consideration of CDN$140 million, prior to closing adjustments. The total consideration comprises cash, common shares of purchaser, and an amortizing interest-bearing loan provided by Enerplus. Production from the assets is approximately 3,400 BOE/day (60% crude oil). The sale closed on October 31, 2022.

Subsequent to the quarter, on November 2, 2022, the Company announced it had entered into a definitive agreement to sell substantially all of its remaining Canadian assets located in Alberta and Saskatchewan for total consideration of CDN$245 million, prior to closing adjustments. The total consideration comprises cash of CDN$210 million and CDN$35 million in common shares of the purchaser. Production from the assets is approximately 3,000 BOE/day (99% crude oil). The sale is expected to close in December 2022.

Capital spending during the third quarter of 2022 was $114.5 million, compared to $132.9 million during the second quarter of 2022, with the majority of the spending focused on our U.S. crude oil properties. The decrease in capital spending was due to less drilling and completions activity during the third quarter of 2022. We are revising our annual capital spending guidance for 2022 to be $430 million from a range between $400 million to $440 million.

Bakken crude oil price differentials continued to trade above WTI due to excess pipeline capacity in the region, and strong physical prices for crude oil delivered to the U.S. Gulf Coast. Our realized Bakken crude oil price differential averaged $2.41/bbl above WTI during the third quarter of 2022, compared to $0.85/bbl above WTI during the second quarter of 2022. Given continued strength in Bakken crude oil price differentials and strong year-to-date realizations, we expect our 2022 realized Bakken crude oil price differential to average $1.25/bbl above WTI, compared to our previous guidance of $1.00/bbl above WTI.

Our realized Marcellus sales price differential widened compared to the previous quarter due to weaker regional prices in September as the market transitioned into the lower-demand shoulder season. Our differential in the third quarter of 2022 averaged $0.99/Mcf below NYMEX, compared to $0.59/Mcf below NYMEX in the second quarter of 2022. A significant portion of our production receives prices reflecting market conditions south of New York at Transco Zone 6 Non-New York, which averaged $0.85/Mcf below NYMEX in the third quarter of 2022. We continue to expect our 2022 realized Marcellus differential to average $0.75/Mcf below NYMEX.

Operating expenses for the third quarter of 2022 increased to $103.8 million, or $10.47/BOE, compared to $83.4 million, or $9.74/BOE during the second quarter of 2022. On a per BOE basis, the amount increased due to higher planned well service activity during the period. We continue to expect our operating expense guidance for 2022 to be $10.00/BOE.

We reported net income of $305.9 million in the third quarter of 2022 compared to net income of $244.4 million in the second quarter of 2022. Higher net income in the third quarter of 2022 was due to a total commodity derivative instruments gain of $57.0 million, compared to a loss of $47.6 million in the second quarter of 2022. The higher commodity derivative instruments gain is due to lower forward market commodity prices at September 30, 2022, and the settlement of existing contracts during the quarter. Net income in the third quarter also benefited from higher production compared to the second quarter of 2022, partially offset by lower realized crude oil prices and higher associated operating costs.

In the third quarter of 2022 cash flow from operating activities increased to $409.9 million, compared to $250.9 million in the second quarter of 2022, primarily due to working capital adjustments and lower realized commodity derivative instrument losses. Third quarter adjusted funds flow increased to $355.6 million from $297.4 million over the same period. The increase was due to lower realized commodity derivative instruments losses and higher production, offset by lower realized crude oil prices.

At September 30, 2022, net debt was $391.1 million and our net debt to adjusted funds flow ratio decreased to 0.3x in the third quarter from 0.5x in the second quarter of 2022. Subsequent to the quarter, on November 3, 2022, Enerplus converted its $400 million revolving bank credit facility to a $365 million sustainability linked lending ("SLL") bank credit facility, and extended the maturity to October 31, 2025. The $365 million SLL bank credit facility has similar targets to Enerplus' $900 million SLL bank credit facility, which was renewed with $50 million maturing on October 31, 2025, and $850 million maturing on October 31, 2026. There were no other significant amendments or additions to the two agreements' terms or covenants.

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

RESULTS OF OPERATIONS

Production

Daily production for the third quarter of 2022 averaged 107,808 BOE/day, an increase of 15% compared to average daily production of 94,142 BOE/day in the second quarter of 2022 with crude oil and natural gas liquids production increasing by 20% over the same period. The increase is primarily the result of 11.8 net wells coming on-stream in North Dakota.

For the three and nine months ended September 30, 2022, total production increased by 9% and 11%, respectively, when compared to the same periods in 2021. The increase in production for the three months ended September 30, 2022, compared to the same period in 2021, was due to higher capital activity in both North Dakota and the Marcellus during 2022. The increase in production for the nine months ended September 30, 2022, was due to additional on-stream activity, as well as a full period of production from the acquisition of Bruin E&P Holdco, LLC (the "Bruin Acquisition") and certain assets in the Williston Basin from Hess Bakken Investment II, LLC (the "Dunn County Acquisition"), which closed during the first half of 2021. The increases were partially offset by the sale of our interests in the Sleeping Giant field in Montana and the Russian Creek area in North Dakota in the Williston Basin, which closed during the fourth quarter of 2021.

Our crude oil and natural gas liquids weighting decreased to 63% from 64% for the three months ended September 30, 2022 and increased to 62% from 60% for the nine months ended September 30, 2022, compared to the same periods in 2021.

We have increased our annual average production guidance for 2022 to 99,750 BOE/day to 101,000 BOE/day, including 61,500 bbls/day to 62,500 bbls/day of crude oil and natural gas liquids, from 97,500 BOE/day to 101,500 BOE/day, including 59,500 bbls/day to 62,500 bbls/day of crude oil and natural gas liquids. For the fourth quarter of 2022, we expect average production of 105,000 BOE/day to 110,000 BOE/day, including 64,000 bbls/day to 68,000 bbls/day of crude oil and natural gas liquids. The updated production guidance includes the impact of the two previously announced Canadian asset divestments.

Average daily production volumes for the three and nine months ended September 30, 2022 and 2021 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2022**	**2021**	**% Change**	**2022**	**2021**	**% Change**
Light and medium oil (bbls/day)	2,038	2,188	(7%)	2,097	2,247	(7%)
Heavy oil (bbls/day)	2,651	3,356	(21%)	2,855	3,328	(14%)
Tight oil (bbls/day)	52,793	49,034	8%	46,194	40,613	14%
Total crude oil (bbls/day)	57,482	54,578	5%	51,146	46,188	11%
Natural gas liquids (bbls/day)	10,900	8,492	28%	9,319	7,246	29%
Conventional natural gas (Mcf/day)	6,909	7,703	(10%)	7,139	7,757	(8%)
Shale gas (Mcf/day)	229,649	209,550	10%	218,706	203,542	7%
Total natural gas (Mcf/day)	236,558	217,253	9%	225,845	211,299	7%
Total daily sales (BOE/day)	107,808	99,279	9%	98,106	88,651	11%

Pricing

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

	Nine months ended September 30,						
Pricing (average for the period)	**2022**	**2021**	**Q3 2022**	**Q2 2022**	**Q1 2022**	**Q4 2021**	**Q3 2021**
Benchmarks							
WTI crude oil ($/bbl)	$ 98.09	$ 64.82	$ 91.56	$ 108.41	$ 94.29	$ 77.19	$ 70.56
Brent (ICE) crude oil ($/bbl)	102.33	67.78	97.81	111.78	97.38	79.80	73.23
Propane – Conway ($/bbl)	49.98	40.87	44.73	51.16	54.05	52.42	49.01
NYMEX natural gas – last day ($/Mcf)	6.77	3.18	8.20	7.17	4.95	5.83	4.01
CDN/US average exchange rate	0.78	0.80	0.77	0.78	0.79	0.79	0.79
CDN/US period end exchange rate	0.72	0.79	0.72	0.78	0.80	0.79	0.79
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 97.44	$ 62.12	$ 92.48	$ 108.77	$ 91.95	$ 75.21	$ 67.22
Natural gas liquids ($/bbl)	34.13	25.40	32.04	33.31	37.78	38.77	29.91
Natural gas ($/Mcf)	5.79	2.58	6.53	6.11	4.62	3.92	3.00
Average differentials							
Bakken DAPL – WTI ($/bbl)	$ 2.43	$ (1.24)	$ 3.60	$ 2.99	$ 0.71	$ 0.53	$ (0.68)
Brent (ICE) – WTI ($/bbl)	4.24	2.98	6.25	3.37	3.09	2.61	2.67
MSW Edmonton – WTI ($/bbl)	(1.82)	(4.14)	(2.01)	(0.50)	(2.96)	(3.10)	(4.07)
WCS Hardisty – WTI ($/bbl)	(15.74)	(12.51)	(19.89)	(12.80)	(14.53)	(14.64)	(13.58)
Transco Leidy monthly – NYMEX ($/Mcf)	(0.89)	(0.95)	(1.06)	(0.90)	(0.71)	(0.92)	(1.11)
Transco Z6 Non-New York monthly – NYMEX ($/Mcf)	(0.10)	(0.43)	(0.85)	(0.87)	1.42	(0.16)	(0.73)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI ($/bbl)	$ 1.07	$ (2.69)	$ 2.41	$ 0.85	$ (0.35)	$ (0.88)	$ (2.26)
Marcellus natural gas – NYMEX ($/Mcf)	(0.53)	(0.49)	(0.99)	(0.59)	0.01	(1.70)	(0.45)
Canada crude oil – WTI ($/bbl)	(14.75)	(12.55)	(15.96)	(12.17)	(16.31)	(13.82)	(12.87)

(1) Excluding transportation costs, 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 third quarter of 2022, our realized crude oil sales price averaged $92.48/bbl, a decrease of 15% compared to the second quarter of 2022, and in line with the decrease in the underlying benchmark WTI price over the same period. Benchmark crude oil prices declined during the quarter largely due to macro-economic factors related to rising inflation and higher interest rates that have elevated risk of a global recession and a decrease in demand for crude oil. The decline in benchmark crude oil prices is also due to the continued release of crude oil Strategic Petroleum Reserve inventories into the U.S. Gulf Coast region. In response to the decline in global oil prices, the Organization of the Petroleum Exporting Countries Plus reduced production quotas in an effort to stabilize crude oil markets.

Bakken crude oil price differentials continued to strengthen during the quarter due to excess pipeline capacity in the region as regional production growth remains muted and strong physical prices for crude oil delivered to the U.S. Gulf Coast. Our realized Bakken crude oil price differential averaged $2.41/bbl above WTI during the third quarter of 2022, compared to $0.85/bbl above WTI during the second quarter of 2022. Given continued strength in Bakken crude oil price differentials and strong year-to-date realizations, we expect our 2022 realized Bakken crude oil price differential to average $1.25/bbl above WTI, compared to our previous guidance of $1.00/bbl above WTI.

Our realized sales price for natural gas liquids averaged $32.04/bbl during the third quarter of 2022 compared to $33.31/bbl during the second quarter of 2022. NGL benchmark prices declined during the quarter due to growing concerns around global recession risk, industrial demand for petrochemical feedstocks and inventory accumulations. Propane, which is the largest component of our NGL production, has experienced a significant decline in pricing as a percent of WTI throughout the year as seasonally low inventories have been restocked and concerns about foreign demand and export strength persist.

NATURAL GAS

Our realized natural gas sales price averaged $6.53/Mcf during the third quarter of 2022, an increase of 7% compared to the second quarter of 2022, while the NYMEX benchmark price increased by 14% over the same period. The difference in price realization versus the benchmark was due to seasonally weaker gas prices in the Marcellus, resulting in a wider differential for the third quarter of 2022.

Our realized Marcellus differential in the third quarter of 2022 averaged $0.99/Mcf below NYMEX compared to $0.59/Mcf below NYMEX in the second quarter of 2022. The decline in our realized differential was due to weaker regional prices in September as the market transitioned into the lower-demand shoulder season. We expect our Marcellus differential to remain supported through the rest of the year given the current local storage deficit and the increase in demand directly attributable to colder weather. Based on current year to date realizations and the outlook for the rest of 2022 we are maintaining our guidance of $0.75/Mcf below NYMEX.

FOREIGN EXCHANGE

Fluctuations in the Canadian and U.S. dollar exchange rate impacts 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 stronger in the third quarter of 2022 at $0.72 CDN/US, compared to $0.78 CDN/US at June 30, 2022 and $0.79 CDN/US at September 30, 2021. The average exchange rate of $0.78 CDN/US for the nine months ended September 30, 2022 was also stronger than the same period in 2021 when it averaged $0.80 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.

Price Risk Management

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

We expect our commodity derivative contracts to continue to protect a portion of our cash flow from operating activities and adjusted funds flow. As of November 3, 2022, we have hedged 17,000 bbls/day for the remainder of 2022. Additionally, we have 15,000 bbls/day hedged for first half of 2023 and 5,000 bbls/day hedged for the second half of 2023. We have also hedged 120,000 Mcf/day for the period from November 1, 2022 to March 31, 2023 and 50,000 Mcf/day for the period from April 1, 2023 to October 31, 2023. Our crude oil contracts consist mainly of three-way collars, which limits upward price participation to the call strike level; additionally, the sold put 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 November 3, 2022:

	WTI Crude Oil ($/bbl)(1)(2)(3)			NYMEX Natural Gas ($/Mcf)(2)		
	Oct 1, 2022 – Dec 31, 2022	**Jan 1, 2023 – Jun 30, 2023**	**Jul 1, 2023 – Dec 31, 2023**	**Oct 1, 2022 – Oct 31, 2022**	**Nov 1, 2022 – Mar 31, 2023**	**Apr 1, 2023 – Oct 31, 2023**
Swaps						
Volume (Mcf/day)	–	–	–	40,000	–	–
Volume (bbls/day)	–	10,000	10,000	–	–	–
Swaps	–	–	–	$ 3.40	–	–
Brent - WTI Spread	–	$ 5.47	$ 5.47	–	–	–
3 Way Collars						
Volume (bbls/day)	17,000	15,000	5,000	–	–	–
Sold Puts	$ 40.00	$ 61.67	$ 65.00	–	–	–
Purchased Puts	$ 50.00	$ 79.33	$ 85.00	–	–	–
Sold Calls	$ 57.91	$ 114.31	$ 128.16	–	–	–
Collars						
Volume (Mcf/day)	–	–	–	60,000	120,000	50,000
Volume (bbls/day)	–	2,000	2,000	–	–	–
Purchased Puts	–	$ 5.00	$ 5.00	$ 3.77	$ 6.27	$ 4.05
Sold Calls	–	$ 75.00	$ 75.00	$ 4.50	$ 18.17	$ 7.00

(1) The total average deferred premium spent on our outstanding crude oil contracts is $1.50/bbl from October 1, 2022 – December 31, 2022 and $1.25/bbl from January 1, 2023 – December 31, 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 E&P Holdco, LLC's outstanding crude oil contracts were recorded at a fair value liability of $76.4 million. At September 30, 2022, the remaining liability was $4.7 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.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses) ($ millions)	**Three months ended September 30, 2022**	**2021**	**Nine months ended September 30, 2022**	**2021**
Realized gains/(losses):				
Crude oil	$ (50.5)	$ (40.3)	$ (233.1)	$ (87.8)
Natural gas	(38.0)	(8.9)	(66.7)	(7.8)
Total realized gains/(losses)	$ (88.5)	$ (49.2)	$ (299.8)	$ (95.6)
Unrealized gains/(losses):				
Crude oil	$ 126.0	$ 3.3	$ 98.8	$ (158.3)
Natural gas	19.5	(11.5)	3.6	(21.6)
Total unrealized gains/(losses)	$ 145.5	$ (8.2)	$ 102.4	$ (179.9)
Total commodity derivative instruments gains/(losses)	$ 57.0	$ (57.4)	$ (197.4)	$ (275.5)

(Per BOE)	**Three months ended September 30, 2022**	**2021**	**Nine months ended September 30, 2022**	**2021**
Total realized gains/(losses)	$ (8.92)	$ (5.39)	$ (11.19)	$ (3.95)
Total unrealized gains/(losses)	14.67	(0.90)	3.82	(7.43)
Total commodity derivative instruments gains/(losses)	$ 5.75	$ (6.29)	$ (7.37)	$ (11.38)

During the three and nine months ended September 30, 2022, Enerplus realized losses of $50.5 million and $233.1 million, respectively, on our crude oil contracts, compared to realized losses of $40.3 million and $87.8 million for the same periods in 2021. For the three and nine months ended September 30, 2022, realized losses of $38.0 million and $66.7 million, respectively, were recorded on our natural gas contracts, compared to realized losses of $8.9 million and $7.8 million for the same periods in 2021. Cash losses recorded during the three and nine months ended September 30, 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 reflected as either a non-cash charge or gain to earnings. At September 30, 2022, the fair value of our crude oil and natural gas contracts was in a net liability position of $23.0 million. For the three and nine months ended September 30, 2022, the change in the fair value of our crude oil contracts resulted in an unrealized gain of $126.0 million and an unrealized gain of $98.8 million, respectively, compared to unrealized gain of $3.3 million and an unrealized loss of $158.3 million, during the same periods in 2021. For the three and nine months ended September 30, 2022, we recorded unrealized gains on our natural gas contracts of $19.5 million and $3.6 million, respectively, compared to unrealized losses of $11.5 million and $21.6 million, during the same periods in 2021.

Crude Oil and Natural Gas Sales

($ millions, except per BOE amounts)	**Three months ended September 30, 2022**	**2021**	**Nine months ended September 30, 2022**	**2021**
Crude oil and natural gas sales	$ 663.5	$ 421.1	$ 1,804.7	$ 982.9
Per BOE	$ 66.90	$ 46.10	$ 67.38	$ 40.61

Crude oil and natural gas sales for the three and nine months ended September 30, 2022 were $663.5 million ($66.90/BOE) and $1,804.7 million ($67.38/BOE), respectively, compared to $421.1 million ($46.10/BOE) and $982.9 million ($40.61/BOE) for the same periods in 2021. The increase in revenue was primarily due to additional production from our capital program and the Bruin and the Dunn County acquisitions completed during the first half of 2021 as well as higher commodity prices.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Operating expenses	$ 103.8	$ 89.1	$ 270.5	$ 212.4
Per BOE	$ 10.47	$ 9.76	$ 10.10	$ 8.78

For three and nine months ended September 30, 2022, operating expenses were $103.8 million, or $10.47/BOE, and $270.5 million, or $10.10/BOE, respectively, compared to $89.1 million, or $9.76/BOE, and $212.4 million, or $8.78/BOE, for the same periods in 2021. The increases were primarily due to the impact of contracts with price escalators linked to WTI crude oil prices and the Consumer Price Index, higher planned well service activity, and higher U.S. crude oil weighting in our production mix partially as a result of the Bruin and Dunn County acquisitions.

We continue to expect our operating expenses guidance for 2022 to be $10.00/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Transportation costs	$ 41.3	$ 32.5	$ 114.9	$ 87.9
Per BOE	$ 4.16	$ 3.56	$ 4.29	$ 3.63

For three and nine months ended September 30, 2022, transportation costs were $41.3 million, or $4.16/BOE, and $114.9 million, or $4.29/BOE, respectively, compared to $32.5 million, or $3.56/BOE, and $87.9 million, or $3.63/BOE, for the same periods in 2021. The increase compared to the same periods in 2021 is primarily the result of increased U.S. production with higher associated transportation costs and additional firm transportation commitments on the Dakota Access Pipeline ("DAPL") as a result of the Bruin Acquisition and participation in the DAPL expansion in August 2021.

We continue to expect our transportation costs guidance for 2022 to be $4.25/BOE.

Production Taxes

($ millions, except per BOE amounts)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Production taxes	$ 48.2	$ 30.4	$ 127.4	$ 69.1
Per BOE	$ 4.86	$ 3.33	$ 4.76	$ 2.86
Production taxes (% of crude oil and natural gas sales)	7.3%	7.2%	7.1%	7.0%

Production taxes for three and nine months ended September 30, 2022 were $48.2 million, or 7.3%, and $127.4 million, or 7.1%, respectively, compared to $30.4 million, or 7.2%, and $69.1 million, or 7.0%, for the same periods in 2021. The increase in total production taxes was due to higher realized prices, as well as higher crude oil production which attracts a higher rate of production tax, compared to the same periods 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.

Netbacks by Property Type	Three months ended September 30, 2022 Crude Oil	Natural Gas	Total
Average Daily Production	79,304 BOE/day	171,027 Mcfe/day	107,808 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 75.60	$ 7.12	$ 66.90
Operating expenses	(13.87)	(0.17)	(10.47)
Transportation costs	(3.72)	(0.90)	(4.16)
Production taxes	(6.46)	(0.07)	(4.86)
Netback before impact of commodity derivative contracts	$ 51.55	$ 5.98	$ 47.41
Realized hedging gains/(losses)	(6.93)	(2.41)	(8.92)
Netback after impact of commodity derivative contracts	$ 44.62	$ 3.57	$ 38.49
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 376.1	$ 94.1	$ 470.2
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 325.6	$ 56.2	$ 381.7

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

Netbacks by Property Type	Three months ended September 30, 2021 Crude Oil	Natural Gas	Total
Average Daily Production	72,425 BOE/day	161,122 Mcfe/day	99,279 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 55.21	$ 3.60	$ 46.10
Operating expenses	(12.89)	(0.22)	(9.76)
Transportation costs	(2.84)	(0.92)	(3.56)
Production taxes	(4.45)	(0.05)	(3.33)
Netback before impact of commodity derivative contracts	$ 35.03	$ 2.41	$ 29.45
Realized hedging gains/(losses)	(6.05)	(0.60)	(5.39)
Netback after impact of commodity derivative contracts	$ 28.98	$ 1.81	$ 24.06
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 233.4	$ 35.7	$ 269.1
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 193.1	$ 26.8	$ 219.9

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

Netbacks by Property Type	Nine months ended September 30, 2022		
	Crude Oil	**Natural Gas**	**Total**
Average Daily Production	69,526 BOE/day	171,481 Mcfe/day	98,106 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 79.73	$ 6.23	$ 67.38
Operating expenses	(13.73)	(0.21)	(10.10)
Transportation costs	(3.84)	(0.90)	(4.29)
Production taxes	(6.57)	(0.06)	(4.76)
Netback before impact of commodity derivative contracts	$ 55.59	$ 5.06	$ 48.23
Realized hedging gains/(losses)	(12.28)	(1.42)	(11.19)
Netback after impact of commodity derivative contracts	$ 43.31	$ 3.64	$ 37.04
Netback before impact of commodity derivative contracts[1] ($ millions)	$ 1,055.1	$ 236.9	$ 1,291.9
Netback after impact of commodity derivative contracts[1] ($ millions)	$ 822.0	$ 170.3	$ 992.1

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

Netbacks by Property Type	Nine months ended September 30, 2021		
	Crude Oil	**Natural Gas**	**Total**
Average Daily Production	61,177 BOE/day	164,835 Mcfe/day	88,651 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 51.41	$ 2.77	$ 40.61
Operating expenses	(12.18)	(0.20)	(8.78)
Transportation costs	(2.82)	(0.91)	(3.63)
Production taxes	(4.04)	(0.04)	(2.86)
Netback before impact of commodity derivative contracts	$ 32.37	$ 1.62	$ 25.34
Realized hedging gains/(losses)	(5.26)	(0.17)	(3.95)
Netback after impact of commodity derivative contracts	$ 27.11	$ 1.45	$ 21.39
Netback before impact of commodity derivative contracts[1] ($ millions)	$ 540.6	$ 72.9	$ 613.5
Netback after impact of commodity derivative contracts[1] ($ millions)	$ 452.8	$ 65.1	$ 517.9

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

Total netbacks before and after hedging for the three and nine months ended September 30, 2022 were higher compared to the same periods in 2021, primarily due to higher production and higher realized prices.

For the three and nine months ended September 30, 2022, crude oil properties accounted for 80% and 82%, respectively, of total netback before hedging, compared to 87% and 88% during the same periods in 2021.

G&A Expenses

Total G&A expenses include G&A expenses and share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans").

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2022	2021	2022	2021
Cash:				
G&A expenses	$ 10.9	$ 8.6	$ 31.5	$ 27.8
Share-based compensation expense	1.2	0.8	3.6	4.9
Non-Cash:				
Share-based compensation expense	3.8	3.4	14.3	4.3
Equity swap gain	—	(0.3)	(1.0)	(1.3)
G&A recovery	(0.1)	(0.1)	(0.3)	(0.3)
Total G&A expenses	$ 15.8	$ 12.4	$ 48.1	$ 35.4

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2022	2021	2022	2021
Cash:				
G&A expenses	$ 1.10	$ 0.94	$ 1.18	$ 1.15
Share-based compensation expense	0.12	0.09	0.13	0.20
Non-Cash:				
Share-based compensation expense	0.38	0.37	0.53	0.18
Equity swap gain	—	(0.03)	(0.04)	(0.05)
G&A recovery	(0.01)	(0.01)	(0.01)	(0.01)
Total G&A expenses	$ 1.59	$ 1.36	$ 1.79	$ 1.47

Cash G&A expenses for three and nine months ended September 30, 2022 were $10.9 million, or $1.10/BOE, and $31.5 million, or $1.18/BOE, respectively, compared to $8.6 million, or $0.94/BOE, and $27.8 million, or $1.15/BOE, for the same periods in 2021. For the three and nine months ended September 30, 2022, total cash G&A expenses increased due to inflationary pressure on labour and services.

SBC can be equity-settled or cash-settled, depending on the underlying plan to which it relates. SBC that is cash-settled for the three and nine months ended September 30, 2022, was $1.2 million, or $0.12/BOE, and $3.6 million, or $0.13/BOE, respectively, compared to $0.8 million, or $0.09/BOE, and $4.9 million, or $0.20/BOE, for the same periods in 2021. For the three months ended September 30, 2022, the higher expense was due to a larger share price increase in 2022 compared to the same period in 2021. For the nine months ended September 30, 2022, the lower expense was due to fewer Director Deferred Share Units outstanding and a smaller share price increase in 2022 compared to the same period in 2021. Equity-settled non-cash SBC for the three and nine months ended September 30, 2022 was $3.8 million, or $0.38/BOE, and $14.3 million, or $0.53/BOE, respectively, compared to $3.4 million, or $0.37/BOE, and $4.3 million, or $0.18/BOE, for the same periods in 2021. Performance Share Units ("PSUs"), as one of the equity-settled LTI plans, are impacted by performance multipliers. For the three and nine months ended September 30, 2022, the multipliers were higher, resulting in an increase in expense compared to the same periods in 2021.

Enerplus had hedged a portion of the outstanding cash-settled units under our LTI plans. During the three and nine months ended September 30, 2022, we recorded a market-to-market gain of nil and $1.0 million, respectively (2021 – gains of $0.3 million and $1.3 million, respectively), as a result of the higher share price. Enerplus settled its equity derivative contracts during the second quarter of 2022 and did not have any equity derivatives outstanding at September 30, 2022.

We continue to expect our cash G&A expenses guidance for 2022 to be $1.20/BOE.

Interest Expense

For the three and nine months ended September 30, 2022, we recorded a total interest expense of $6.5 million and $18.6 million, respectively, compared to $8.2 million and $21.6 million for the same periods in 2021. The decrease was primarily due to lower debt levels during the three and nine months ended September 30, 2022, as cash flow was used to repay debt incurred in 2021 to fund the Bruin and Dunn County acquisitions. During the nine months ended September 30, 2022, we made a principal payment on our 2014 senior notes, and our third principal payment and final bullet payment outstanding on our 2012 senior notes.

At September 30, 2022, approximately 47% of Enerplus' debt was based on fixed interest rates and 53% on floating interest rates, with weighted average interest rates of 4.2% and 2.5%, respectively.

Foreign Exchange

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2022	2021	2022	2021
Realized:				
Foreign exchange (gain)/loss	$ 0.1	$ 0.5	$ —	$ 2.9
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company	(1.0)	(0.3)	(1.1)	(1.9)
Unrealized:				
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company	17.0	(14.2)	14.9	(7.2)
Total foreign exchange (gain)/loss	$ 16.1	$ (14.0)	$ 13.8	$ (6.2)
CDN/US average exchange rate	0.77	0.79	0.78	0.80
CDN/US period end exchange rate	0.72	0.79	0.72	0.79

For three and nine months ended September 30, 2022, Enerplus recorded foreign exchange losses of $16.1 million and $13.8 million, respectively, compared to gains of $14.0 million and $6.2 million for the same periods 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 September 30, 2022, $203.2 million of outstanding senior notes and $230.0 million drawn on the SLL bank credit facility and revolving bank credit facility (together referred to as 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 and nine months ended September 30, 2022, Other Comprehensive Income/(Loss) included unrealized losses of $24.3 million and $33.0 million, respectively, on our U.S. dollar denominated senior notes and Bank Credit Facilities compared to an unrealized loss of $13.7 million and an unrealized gain of $2.2 million, for the same periods in 2021.

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

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2022	2021	2022	2021
Capital spending(1)	$ 114.5	$ 63.6	$ 346.4	$ 221.3
Office capital	0.2	0.3	0.6	2.0
Sub-total	114.7	63.9	347.0	223.3
Bruin Acquisition	$ —	$ —	$ —	$ 520.2
Dunn County Acquisition	—	—	—	305.1
Property and land acquisitions	16.3	3.1	19.7	7.1
Property divestments(1)	(4.2)	0.2	(19.4)	(3.8)
Sub-total	12.1	3.3	0.3	828.6
Total	$ 126.8	$ 67.2	$ 347.3	$ 1,051.9

(1) Excludes changes in non-cash investing working capital.

Capital spending for the three and nine months ended September 30, 2022 totaled $114.5 million and $346.4 million, respectively, compared to $63.6 million and $221.3 million for the same periods in 2021. The increase is mainly due to increased capital activity on our North Dakota properties. Capital spending during the third quarter of 2022 included $94.2 million on our U.S. crude oil properties and $15.7 million on our Marcellus natural gas properties.

During the first nine months of 2021, we completed the Bruin Acquisition for total cash consideration of $465.0 million, or $420.2 million after purchase price adjustments, with $520.2 million allocated to PP&E, excluding the assumed asset retirement obligation. We also completed the Dunn County Acquisition for total cash consideration of $306.8 million, with $305.1 million allocated to PP&E, excluding the assumed asset retirement obligation.

Property divestments for the three and nine months ended September 30, 2022 were $4.2 million and $19.4 million, respectively, compared to nil and $3.8 million, respectively, for the same periods in 2021. Property divestments for the nine months ended September 30, 2022 relate to the sale of minor non-operated interests in North Dakota and Pennsylvania.

On July 28, 2022, the Company announced it had entered into a definitive agreement to sell certain Canadian assets located in Alberta for total consideration of CDN$140 million, prior to closing adjustments. The total consideration comprises cash, common shares of purchaser, and an amortizing interest-bearing loan provided by Enerplus. Production from the assets is approximately 3,400 BOE/day (60% crude oil). The sale closed on October 31, 2022.

Subsequent to the quarter, on November 2, 2022, the Company announced it had entered into a definitive agreement to sell substantially all of its remaining Canadian assets located in Alberta and Saskatchewan for total consideration of CDN$245 million, prior to closing adjustments. The total consideration comprises cash of CDN$210 million and CDN$35 million in common shares of the purchaser. Production from the assets is approximately 3,000 BOE/day (99% crude oil). The sale is expected to close in December 2022.

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

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

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2022	2021	2022	2021
DD&A expense	$ 82.2	$ 81.3	$ 219.0	$ 194.4
Per BOE	$ 8.29	$ 8.90	$ 8.18	$ 8.03

DD&A related to PP&E is recognized using the unit of production method based on proved reserves. Enerplus recorded DD&A expense of $82.2 million, or $8.29/BOE, for the three months ended September 30, 2022 compared to $81.3 million, or $8.90/BOE, in the same period in 2021. The decrease in per BOE for the three months ended September 30, 2022 is primarily a result of reserve additions and revisions at December 31, 2021. For the nine months ended September 30, 2022, DD&A expense was $219.0 million, or $8.18/BOE, and $194.4 million, or $8.03/BOE, for the same period in 2021. The increase in total DD&A expense and per BOE is a result of additional production volumes and higher PP&E costs from the Bruin and the Dunn County acquisitions, partially offset by reserve additions and revisions at December 31, 2021.

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 U.S. Securities and Exchange Commission (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 2022. There were no impairments for the three and nine months ended September 30, 2022. For the three and nine months ended September 30, 2021, we recorded a PP&E impairment of nil and $3.4 million, respectively, 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 $155.2 million at September 30, 2022, compared to $132.8 million at December 31, 2021.

For the three and nine months ended September 30, 2022, ARO settlements were $1.6 million and $12.7 million, respectively, compared to $1.7 million and $8.5 million, respectively, during the same periods in 2021.

Enerplus benefited from provincial government assistance to support the clean-up 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 and nine months ended September 30, 2022, Enerplus benefitted from $0.3 million and $0.8 million, respectively, in government assistance compared to $0.2 million and $2.1 million, respectively, for the same periods in 2021.

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 September 30, 2022, our total lease liability was $23.0 million (December 31, 2021 - $28.9 million). In addition, ROU assets of $20.5 million were recorded, which relate to our lease liabilities less lease incentives (December 31, 2021 - $26.1 million).

Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2022	2021	2022	2021
Current tax expense/(recovery)	$ 7.9	$ (0.9)	$ 24.9	$ 2.5
Deferred tax expense/(recovery)	93.1	31.4	174.6	31.1
Total tax expense/(recovery)	$ 101.0	$ 30.5	$ 199.5	$ 33.6

For the three and nine months ended September 30, 2022, we recorded a current tax expense of $7.9 million and $24.9 million, respectively, compared to a recovery of $0.9 million and an expense of $2.5 million for the same periods in 2021. The increase in current tax in 2022 is due to additional U.S. Federal and state tax resulting from higher net income for the year and the utilization of the majority of our net operating loss carryforward. Many factors influence taxable income including future commodity prices, production levels, development activities, capital spending, and overall profitability. We continue to expect 2022 cash tax of 2.0% – 3.0% of adjusted funds flow before tax assuming WTI of $85.00/bbl and NYMEX of $6.00/Mcf.

For the three and nine months ended September 30, 2022, we recorded a deferred income tax expense of $93.1 million and $174.6 million, respectively, compared to an expense of $31.4 million and $31.1 million for the same periods in 2021. The higher deferred tax expense in 2022 is due to higher income.

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 nine months ended September 30, 2022, no valuation allowance was recorded against our Canadian income related deferred tax asset, however, a full valuation allowance has been recorded against our deferred income tax assets related to capital items. Our deferred income tax asset recorded in Canada is $197.4 million offset by a deferred income tax liability in the U.S. of $11.1 million as at September 30, 2022 (December 31, 2021 - $380.9 million net asset).

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 nine months, after which it drops to 3.0x. At September 30, 2022, our senior debt to adjusted EBITDA ratio was 0.4x and our net debt to adjusted funds flow ratio was 0.3x. Although a capital management 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.

Net debt at September 30, 2022 decreased to $391.1 million, compared to $640.4 million at December 31, 2021. Total debt was comprised of our senior notes and Bank Credit Facilities, totaling $433.2 million, less cash on hand of $42.2 million.
At September 30, 2022, through our Bank Credit Facilities, we had total credit capacity of $1.3 billion, of which $230.0 million was drawn. We expect to finance our working capital requirements through cash, adjusted funds flow and our credit capacity. We have sufficient liquidity to meet our financial commitments for the near term.

Subsequent to the quarter, on November 3, 2022, Enerplus converted its $400 million revolving bank credit facility to a $365 million SLL bank credit facility, and extended the maturity to October 31, 2025. The $365 million SLL bank credit facility has similar targets to Enerplus' $900 million SLL bank credit facility, which was renewed with $50 million maturing on October 31, 2025, and $850 million maturing on October 31, 2026. There were no other significant amendments or additions to the two agreements' terms or covenants.

Our reinvestment rate[1] was 32% and 38% for the three and nine months ended September 30, 2022, respectively, compared to 31% and 49%, respectively, for the same periods in 2021.

During the three and nine months ended September 30, 2022, a total of $123.3 million and $271.3 million, respectively, was returned to shareholders through share repurchases and dividends, compared to $18.1 million and $32.8 million for the same periods in 2021. During the third quarter of 2022, we announced our intention to increase our expected 2022 return of capital to at least 60% of free cash flow[1] commencing in the second half of 2022 and continuing through 2023, an increase from 50% of free cash flow in the first half of 2022. We also previously announced an increase to the expected minimum return of capital level to $425 million for 2022. Subsequent to the quarter, the Board of Directors approved a 10% increase to the quarterly dividend to $0.055 per share, from $0.050 per share, beginning December 2022. We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

During the three months ended September 30, 2022, a total of 7,913,168 common shares were repurchased and cancelled under the Normal Course Issuer Bid ("NCIB") at an average price of $14.13 per share, for total consideration of $111.8 million. During the nine months ended September 30, 2022, a total of 18,126,090 common shares were repurchased and cancelled under the NCIB at an average price of $13.35 per share, for total consideration of $241.9 million. During the three and nine months ended September 30, 2021, 1,657,650 common shares were repurchased and cancelled under the NCIB at an average price of $6.12 per share, for total consideration of $10.1 million.

At September 30, 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.

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

The following table lists our financial covenants at September 30, 2022:

Covenant Description		September 30, 2022
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA	3.5x	0.4x
Total debt to adjusted EBITDA	4.0x	0.4x
Total debt to capitalization	55%	21%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA[(1)]	3.0x - 3.5x	0.4x
Senior debt to consolidated present value of total proved reserves[(2)]	60%	11%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	50.0x

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 September 30, 2022 was $370.6 million and $1,218.5 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 September 30,		Nine months ended September 30,	
($ millions, except per share amounts)	2022	2021	2022	2021
Dividends[(1)]	$ 11.5	$ 7.9	$ 29.4	$ 22.7
Per weighted average share (Basic)	$ 0.050	$ 0.030	$ 0.126	$ 0.089

(1) Excludes changes in non-cash financing working capital.

During the three and nine months ended September 30, 2022, we declared total dividends of $11.5 million, or $0.050 per share, and $29.4 million, or $0.126 per share, respectively, compared to $7.9 million, or $0.030 per share, and $22.7 million, or $0.089 per share, for the same periods in 2021. The total amount of dividends paid to shareholders has increased compared to the same period in 2021 due to the increased sustainability of the business and our intention to increase return of capital to shareholders.

Subsequent to the quarter, the Board of Directors approved a 10% increase to the quarterly dividend to $0.055 per share, from $0.050 per share, beginning December 2022. We expect to fund the dividend through the free cash flow generated by the business.

Shareholders' Capital

	Nine months ended September 30,	
	2022	2021
Share capital ($ millions)	$ 2,926.2	$ 3,206.2
Common shares outstanding (thousands)	226,966	255,092
Weighted average shares outstanding – basic (thousands)	237,835	252,432
Weighted average shares outstanding – diluted (thousands)	245,403	256,900

For the nine months ended September 30, 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 total amount of $11.6 million (2021 – $3.6 million).

During the third quarter, Enerplus received approval from the Toronto Stock Exchange ("TSX") to renew its NCIB to purchase up to 10% of the public float (within the meaning of the TSX rules) during a 12-month period. Enerplus completed its previous NCIB in July 2022.

During the nine months ended September 30, 2022, 18,126,090 common shares were repurchased and cancelled under the NCIB at an average price of $13.35 per share, for total consideration of $241.9 million. Of the amount paid, $175.8 million was charged to share capital and $66.1 million was credited to accumulated deficit. At September 30, 2022, 17,682,231 common shares were available for repurchase under the current NCIB.

During the nine months ended September 30, 2021, 1,657,650 common shares were repurchased and cancelled under the NCIB at an average price of $6.12 per share, for total consideration of $10.1 million. Of the amount paid, $16.5 million was charged to share capital and $6.4 million was credited to accumulated deficit.

Subsequent to September 30, 2022 and up to November 2, 2022, we repurchased 2,729,590 common shares under the NCIB at an average price of $16.00 per common share, for total consideration of $43.7 million.

At November 2, 2022, we had 224,236,699 common shares outstanding. In addition, an aggregate of 10,297,759 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.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended September 30, 2022			Three months ended September 30, 2021		
($ millions, except per unit amounts)	U.S.	Canada	Total	U.S.	Canada	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	52,793	4,689	57,482	49,035	5,543	54,578
Natural gas liquids (bbls/day)	10,612	288	10,900	8,209	283	8,492
Natural gas (Mcf/day)	229,466	7,092	236,558	209,454	7,799	217,253
Total average daily production (BOE/day)	101,649	6,159	107,808	92,153	7,126	99,279
Pricing[1]						
Crude oil ($/bbl)	$ 93.96	$ 75.76	$ 92.48	$ 68.31	$ 57.66	$ 67.22
Natural gas liquids ($/bbl)	31.53	50.85	32.04	29.50	41.84	29.91
Natural gas ($/Mcf)	6.61	3.97	6.53	2.97	3.86	3.00
Property, Plant and Equipment						
Capital and office expenditures	$ 113.6	$ 1.1	$ 114.7	$ 61.0	$ 2.9	$ 63.9
Acquisitions, including property and land	16.0	0.3	16.3	2.7	0.4	3.1
Property divestments	(4.3)	0.1	(4.2)	—	0.2	0.2
Netback Before Impact of Commodity Derivative Contracts[2]						
Crude oil and natural gas sales	$ 626.7	$ 36.8	$ 663.5	$ 387.6	$ 33.5	$ 421.1
Operating expenses	(91.4)	(12.4)	(103.8)	(79.0)	(10.1)	(89.1)
Transportation cost	(40.1)	(1.2)	(41.3)	(31.0)	(1.5)	(32.5)
Production taxes	(47.4)	(0.8)	(48.2)	(29.9)	(0.5)	(30.4)
Netback before impact of commodity derivative contracts	$ 447.8	$ 22.4	$ 470.2	$ 247.7	$ 21.4	$ 269.1
Other Expenses						
Commodity derivative instruments (gain)/loss	$ —	$ (57.0)	$ (57.0)	$ —	$ 57.4	$ 57.4
General and administrative expense[3]	1.3	14.5	15.8	6.5	5.9	12.4
Current income tax expense/(recovery)	7.9	—	7.9	(0.9)	—	(0.9)

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

($ millions, except per unit amounts)	Nine months ended September 30, 2022 U.S.	Canada	Total	Nine months ended September 30, 2021 U.S.	Canada	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	46,193	4,953	51,146	40,614	5,574	46,188
Natural gas liquids (bbls/day)	9,021	298	9,319	6,916	330	7,246
Natural gas (Mcf/day)	218,505	7,340	225,845	203,296	8,003	211,299
Total average daily production (BOE/day)	91,632	6,474	98,106	81,413	7,238	88,651
Pricing[(1)]						
Crude oil ($/bbl)	$ 98.95	$ 83.34	$ 97.44	$ 63.48	$ 52.26	$ 62.12
Natural gas liquids ($/bbl)	33.45	54.78	34.13	24.98	34.25	25.40
Natural gas ($/Mcf)	5.82	4.92	5.79	2.54	3.52	2.58
Property, Plant and Equipment						
Capital and office expenditures	$ 341.8	$ 5.2	$ 347.0	$ 213.0	$ 10.3	$ 223.3
Acquisitions, including property and land	18.6	1.1	19.7	830.7	1.7	832.4
Property divestments	(19.5)	0.1	(19.4)	—	(3.8)	(3.8)
Netback Before Impact of Commodity Derivative Contracts[(2)]						
Crude oil and natural gas sales	$ 1,677.2	$ 127.5	$ 1,804.7	$ 892.1	$ 90.8	$ 982.9
Operating expenses	(235.5)	(35.0)	(270.5)	(181.5)	(30.9)	(212.4)
Transportation cost	(111.3)	(3.6)	(114.9)	(83.1)	(4.8)	(87.9)
Production taxes	(125.2)	(2.2)	(127.4)	(67.6)	(1.5)	(69.1)
Netback before impact of commodity derivative contracts	$ 1,205.2	$ 86.7	$ 1,291.9	$ 559.9	$ 53.6	$ 613.5
Other Expenses						
Commodity derivative instruments (gain)/loss	$ —	$ 197.4	$ 197.4	$ —	$ 275.5	$ 275.5
General and administrative expense[(3)]	19.0	29.1	48.1	23.9	11.5	35.4
Current income tax expense/(recovery)	24.9	—	24.9	2.5	—	2.5

(1) Before transportation costs and the effects of commodity derivative instruments.
(2) This financial measure is a non-GAAP financial measure. See “Non-GAAP 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	Diluted
2022				
Third Quarter	$ 663.5	$ 305.9	$ 1.32	$ 1.28
Second Quarter	628.0	244.4	1.01	0.99
First Quarter	513.2	33.2	0.14	0.13
Total 2022	$ 1,804.7	$ 583.6	$ 2.47	$ 2.40
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 $663.5 million during the third quarter of 2022, compared to $628.0 million during the second quarter of 2022. The increase in crude oil and natural gas sales was a result of higher production during the third quarter of 2022 compared to the second quarter of 2022. We reported net income of $305.9 million during the third quarter of 2022 compared to net income of $244.4 million during the second quarter of 2022. The increase was primarily due to a gain recorded on commodity derivative instruments of $57.0 million during the third quarter of 2022, compared to a $47.6 million loss recorded in the second quarter of 2022.

Crude oil and natural gas sales increased in 2021 compared to 2020 due to higher production from the Bruin and the 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.

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

The following table summarizes our updated 2022 guidance and includes the impact of the two previously announced Canadian asset divestments.

Summary of 2022 Annual Expectations	Target Annual Results
Capital spending ($ millions)	$430 (from $400 - $440)
Average annual production (BOE/day)	99,750 - 101,000 (from 97,500 - 101,500)
Average annual crude oil and natural gas liquids production (bbls/day)	61,500 - 62,500 (from 59,500 - 62,500)
Fourth quarter average production (BOE/day)	105,000 - 110,000
Fourth quarter average crude oil and natural gas liquids production (bbls/day)	64,000 - 68,000
Average production tax rate (% of gross sales, before transportation)	7%
Operating expenses (per BOE)	$10.00
Transportation costs (per BOE)	$4.25
Cash G&A expenses (per BOE)	$1.20
Current tax expense	2% - 3% of adjusted funds flow before tax

Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	$1.25/bbl (from $1.00/bbl)
Average Marcellus natural gas differential (compared to NYMEX natural gas)	$(0.75)/Mcf

(1) 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 net income/(loss)" 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 adjustments or valuation allowances on deferred taxes were recorded for the three and nine months ended September 30, 2022 and 2021. The calculation follows:

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2022	2021	2022	2021
Net income/(loss)	**$ 305.9**	**$ 98.1**	**$ 583.6**	**$ 57.5**
Unrealized derivative instrument (gain)/loss	(145.5)	8.0	(103.4)	178.6
Asset impairment	—	—	—	3.4
Other expense related to investing activities	—	—	13.1	—
Unrealized foreign exchange (gain)/loss	17.0	(14.2)	14.9	(7.2)
Tax effect on above items	30.5	0.2	17.8	(41.7)
Other income related to investing activities	—	(4.6)	—	(4.6)
Adjusted net income/(loss)	**$ 207.9**	**$ 87.5**	**$ 526.0**	**$ 186.0**

"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. The most directly comparable GAAP measure is cash flow from operating activities.

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2022	2021	2022	2021
Cash flow from/(used in) operating activities	$ 409.9	$ 182.2	$ 856.8	$ 321.3
Asset retirement obligation settlements	1.6	1.7	12.7	8.5
Changes in non-cash operating working capital	(55.9)	19.3	45.4	124.2
Adjusted funds flow	**$ 355.6**	**$ 203.2**	**$ 914.9**	**$ 454.0**
Capital spending	(114.5)	(63.6)	(346.4)	(221.3)
Free cash flow	**$ 241.1**	**$ 139.6**	**$ 568.5**	**$ 232.7**

"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 below:

	Three months ended September 30,		**Nine months ended September 30,**	
($ millions)	**2022**	**2021**	**2022**	**2021**
Crude oil and natural gas sales	$ 663.5	$ 421.1	$ 1,804.7	$ 982.9
Less:				
Operating expenses	(103.8)	(89.1)	(270.5)	(212.4)
Transportation expenses	(41.3)	(32.5)	(114.9)	(87.9)
Production taxes	(48.2)	(30.4)	(127.4)	(69.1)
Netback before impact of commodity derivative contracts	**$ 470.2**	**$ 269.1**	**$ 1,291.9**	**$ 613.5**
Net realized gain/(loss) on derivative instruments	(88.5)	(49.2)	(299.8)	(95.6)
Netback after impact of commodity derivative contracts	**$ 381.7**	**$ 219.9**	**$ 992.1**	**$ 517.9**

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:

"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.

"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.

"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.

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.

"Reinvestment rate" Comparing the amount of our capital spending to adjusted funds flow (as a percentage).

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 September 30, 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 July 1, 2022 and ended September 30, 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: Enerplus' return of capital plans, including expectations regarding payment of dividends and the source of funds related thereto; expectations regarding Enerplus' share repurchase program, including timing and amounts thereof and the funding of the share repurchase program from free cash flow; the sale of Enerplus’ assets in Canada and the completion, timing, and anticipated benefits and proceeds thereof; expected impact of the sale of Enerplus’ assets in Canada on its operations and financial results, including updated 2022 and future capital spending guidance and expected capital spending levels in 2023 and the future, and the impact thereof on our production levels and land holdings; expected production volumes in 2022, including the production mix, and updated 2022 production guidance; 2022 capital spending guidance and expected capital spending levels in 2022; expectations regarding free cash flow generation and long-term capital spending reinvestment rates; expected operating strategy in 2022; 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 updated 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 and the time at which cash taxes may be paid; expected 2022 cash tax as a percentage of adjusted funds flow before tax; future debt and working capital levels, financial capacity, liquidity and capital resources to fund capital spending, working capital requirements and deficits and senior note repayments; expectations regarding our ability to comply with or renegotiate debt covenants under the Bank Credit Facilities and outstanding senior notes; and our future acquisitions and dispositions.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: the ability to fund our return of capital plans, including both dividends at the current level and the share repurchase program, from free cash flow as expected; that our common share trading price will be at levels, and that there will be no other alternatives, that, in each case, make share repurchases an appropriate and best strategic use of our free cash flows; the timing and proceeds from the sale of Enerplus’ remaining assets in Canada, as well as benefits of the sale of Enerplus’ assets in Canada and its ability to realize such benefits; 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 closing of the sale of Enerplus’ remaining assets in Canada in a timely manner and pursuant to the terms thereof; our ability to comply with our debt covenants; our ability to meet the targets associated with the SLL bank credit facility; 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 $6.00/Mcf, a Bakken crude oil price differential of $1.25/bbl above WTI, a Marcellus natural gas price differential of $0.75/Mcf below NYMEX and a CDN/USD exchange rate of $0.72. 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 increased 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 achieve the expected timing, or realize anticipated proceeds or benefits, of the sale of Enerplus' assets in Canada; continued instability, or further deterioration, in global economic and market environment, including from COVID-19 or similar events, 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, including global energy demand; volatility in our common share trading price and free cash flow that could impact our planned share repurchases and dividend levels; 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), which are available at www.sedar.com, www.sec.gov *and through Enerplus' website at* www.enerplus.com.

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. Any forward-looking information contained herein are expressly qualified by this cautionary statement.

Condensed Consolidated Balance Sheets

(US$ thousands) unaudited	Note	September 30, 2022	December 31, 2021
Assets			
Current assets			
Cash and cash equivalents		$ 42,185	$ 61,348
Accounts receivable	3	313,770	227,988
Other current assets	6	11,129	10,956
Derivative financial assets	16	15,179	5,668
		382,263	305,960
Property, plant and equipment:			
Crude oil and natural gas properties (full cost method)	4, 5	1,418,814	1,253,505
Other capital assets	4	11,028	13,887
Property, plant and equipment		1,429,842	1,267,392
Other long-term assets	6	7,485	9,756
Right-of-use assets	10	20,490	26,118
Derivative financial assets	16	3,407	—
Deferred income tax asset	14	197,420	380,858
Total Assets		$ 2,040,907	$ 1,990,084
Liabilities			
Current liabilities			
Accounts payable	7	$ 453,684	$ 367,008
Income tax payable	14	1,878	—
Current portion of long-term debt	8	80,600	100,600
Derivative financial liabilities	16	39,454	143,200
Current portion of lease liabilities	10	11,342	10,618
		586,958	621,426
Long-term debt	8	352,644	601,171
Asset retirement obligation	9	155,168	132,814
Derivative financial liabilities	16	2,181	7,098
Lease liabilities	10	11,619	18,265
Deferred income tax liability	14	11,112	—
		532,724	759,348
Total Liabilities		1,119,682	1,380,774
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: September 30, 2022 – 227 million shares			
December 31, 2021 – 244 million shares	15	2,926,217	3,094,061
Paid-in capital		45,608	50,881
Accumulated deficit		(1,750,237)	(2,238,325)
Accumulated other comprehensive loss		(300,363)	(297,307)
		921,225	609,310
Total Liabilities & Shareholders' Equity		$ 2,040,907	$ 1,990,084
Subsequent Events	8, 15, 18		

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Condensed Consolidated Statements of Income/(Loss) and Comprehensive Income/(Loss)

(US$ thousands, except per share amounts) unaudited	Note	Three months ended September 30, 2022	Three months ended September 30, 2021	Nine months ended September 30, 2022	Nine months ended September 30, 2021
Revenues					
Crude oil and natural gas sales	11	$ 663,532	$ 421,133	$ 1,804,701	$ 982,945
Commodity derivative instruments gain/(loss)	16	56,995	(57,447)	(197,368)	(275,532)
		720,527	363,686	1,607,333	707,413
Expenses					
Operating		103,841	89,102	270,451	212,423
Transportation		41,312	32,508	114,949	87,910
Production taxes		48,169	30,364	127,351	69,132
General and administrative	12	15,745	12,401	48,013	35,376
Depletion, depreciation and accretion		82,225	81,250	219,006	194,392
Asset impairment	5	—	—	—	3,420
Interest		6,471	8,232	18,624	21,642
Foreign exchange (gain)/loss	13	16,109	(14,023)	13,764	(6,269)
Transaction costs and other expense/(income)	9	(368)	(4,735)	12,020	(1,679)
		313,504	235,099	824,178	616,347
Income/(Loss) before taxes		407,023	128,587	783,155	91,066
Current income tax expense/(recovery)	14	7,929	(926)	24,929	2,489
Deferred income tax expense/(recovery)	14	93,149	31,401	174,632	31,049
Net Income/(Loss)		$ 305,945	$ 98,112	$ 583,594	$ 57,528
Other Comprehensive Income/(Loss)					
Unrealized gain/(loss) on foreign currency translation		28,582	(5,111)	29,939	(5,830)
Foreign exchange gain/(loss) on net investment hedge, net of tax	16	(24,276)	(13,728)	(32,995)	2,164
Total Comprehensive Income/(Loss)		$ 310,251	$ 79,273	$ 580,538	$ 53,862
Net Income/(Loss) per share					
Basic	15	$ 1.32	$ 0.38	$ 2.47	$ 0.22
Diluted	15	$ 1.28	$ 0.38	$ 2.40	$ 0.22

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Condensed Consolidated Statements of Changes in Shareholders' Equity

(US$ thousands) unaudited	Three months ended September 30, 2022	Three months ended September 30, 2021	Nine months ended September 30, 2022	Nine months ended September 30, 2021
Share Capital				
Balance, beginning of period	$ 3,001,604	$ 3,222,747	$ 3,094,061	$ 3,113,829
Issue of shares (net of tax effected issue costs)	—	—	—	99,516
Purchase of common shares under Normal Course Issuer Bid	(75,387)	(16,500)	(175,803)	(16,500)
Share-based compensation – treasury settled	—	—	7,959	9,402
Balance, end of period	$ 2,926,217	$ 3,206,247	$ 2,926,217	$ 3,206,247
Paid-in Capital				
Balance, beginning of period	$ 41,843	$ 38,056	$ 50,881	$ 49,382
Share-based compensation – tax withholdings settled in cash	—	—	(11,567)	(3,551)
Share-based compensation – treasury settled	—	—	(7,959)	(9,402)
Share-based compensation – non-cash	3,765	3,369	14,253	4,996
Balance, end of period	$ 45,608	$ 41,425	$ 45,608	$ 41,425
Accumulated Deficit				
Balance, beginning of period	$ (2,008,253)	$ (2,503,041)	$ (2,238,325)	$ (2,447,735)
Purchase of common shares under Normal Course Issuer Bid	(36,413)	6,349	(66,132)	6,349
Net income/(loss)	305,945	98,112	583,594	57,528
Dividends declared(1)	(11,516)	(7,929)	(29,374)	(22,651)
Balance, end of period	$ (1,750,237)	$ (2,406,509)	$ (1,750,237)	$ (2,406,509)
Accumulated Other Comprehensive Income/(Loss)				
Balance, beginning of period	$ (304,669)	$ (279,338)	$ (297,307)	$ (294,511)
Unrealized gain/(loss) on foreign currency translation	28,582	(5,111)	29,939	(5,830)
Foreign exchange gain/(loss) on net investment hedge, net of tax	(24,276)	(13,728)	(32,995)	2,164
Balance, end of period	$ (300,363)	$ (298,177)	$ (300,363)	$ (298,177)
Total Shareholders' Equity	$ 921,225	$ 542,986	$ 921,225	$ 542,986

(1) For the three and nine months ended September 30, 2022, dividends declared were $0.050 per share and $0.126 per share, respectively (2021 – $0.030 per share and $0.089 per share, respectively).

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Condensed Consolidated Statements of Cash Flows

(US$ thousands) unaudited	Note	Three months ended September 30, 2022	Three months ended September 30, 2021	Nine months ended September 30, 2022	Nine months ended September 30, 2021
Operating Activities					
Net income/(loss)		$ 305,945	$ 98,112	$ 583,594	$ 57,528
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		82,225	81,250	219,006	194,392
Asset impairment	5	—	—	—	3,420
Changes in fair value of derivative instruments	16	(145,480)	7,963	(103,423)	178,601
Deferred income tax expense/(recovery)	14	93,149	31,401	174,632	31,049
Foreign exchange (gain)/loss on debt and working capital	13	16,997	(14,234)	14,876	(7,229)
Share-based compensation and general and administrative	12,15	3,665	3,277	13,959	4,060
Other expense/(income)	9	(289)	(176)	12,267	(2,093)
Amortization of debt issuance costs	8	366	419	1,070	728
Translation of U.S. dollar cash held in parent company	13	(956)	(288)	(1,071)	(1,907)
Other income reclassified to Investing Activities	17	—	(4,593)	—	(4,593)
Asset retirement obligation settlements	9	(1,560)	(1,681)	(12,704)	(8,461)
Changes in non-cash operating working capital	17	55,884	(19,273)	(45,408)	(124,190)
Cash flow from/(used in) operating activities		409,946	182,177	856,798	321,305
Financing Activities					
Drawings from/(repayment of) bank credit facilities	8	(130,315)	(106,000)	(186,015)	569,000
Repayment of senior notes	8	(21,000)	—	(100,600)	(81,600)
Debt issuance costs	8	—	—	—	(4,621)
Proceeds from the issuance of shares	15	—	—	—	98,339
Purchase of common shares under Normal Course Issuer Bid	15	(111,800)	(10,151)	(241,935)	(10,151)
Share-based compensation – tax withholdings settled in cash	15	—	—	(11,567)	(3,551)
Dividends	15,17	(11,516)	(7,929)	(29,374)	(24,400)
Cash flow from/(used in) financing activities		(274,631)	(124,080)	(569,491)	543,016
Investing Activities					
Capital and office expenditures	17	(121,382)	(77,719)	(311,449)	(193,266)
Bruin acquisition	6	—	—	—	(420,249)
Dunn County acquisition	6	—	(188)	—	(305,076)
Property and land acquisitions		(16,252)	(3,079)	(19,662)	(7,102)
Property divestments	9,17	4,214	(216)	6,333	3,782
Other expense/(income)		—	4,593	—	4,593
Cash flow from/(used in) investing activities		(133,420)	(76,609)	(324,778)	(917,318)
Effect of exchange rate changes on cash & cash equivalents		14,884	471	18,308	5,729
Change in cash and cash equivalents		16,779	(18,041)	(19,163)	(47,268)
Cash and cash equivalents, beginning of period		25,406	60,718	61,348	89,945
Cash and cash equivalents, end of period		$ 42,185	$ 42,677	$ 42,185	$ 42,677

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Notes to Condensed Consolidated Financial Statements
(unaudited)

1) REPORTING ENTITY

These interim Condensed Consolidated Financial Statements ("interim Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation (the "Company" or "Enerplus") including its Canadian and United States ("U.S.") subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' corporate offices are located in Calgary, Alberta, Canada and Denver, Colorado, United States.

2) BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under accounting principles generally accepted in the United States of America ("U.S. GAAP") for the three and nine months ended September 30, 2022 and the 2021 comparative periods. In the fourth quarter of 2021, the Company elected to change its reporting currency from Canadian dollars to U.S. dollars since the majority of its crude oil and natural gas properties are located in the U.S., and to facilitate a more direct comparison to other U.S. exploration and development companies. The change in reporting currency is a voluntary change which is accounted for retrospectively. All prior period amounts have been restated to reflect U.S. dollars as the reporting currency. Certain prior period amounts have been reclassified to conform with current period presentation. Certain information and notes normally included with the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with Enerplus' annual audited Consolidated Financial Statements as of December 31, 2021.

These unaudited interim Consolidated Financial Statements reflect, in the opinion of Management, all normal and recurring adjustments necessary to present fairly the financial position and results of the Company as at and for the periods presented.

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Actual results could differ from these estimates, and changes in estimates are recorded when known. Significant estimates made by management include those that relate to: crude oil and natural gas reserves and related present value of future cash flows, depreciation, depletion and accretion ("DD&A"), impairment of property, plant and equipment, asset retirement obligations, income taxes, ability to realize deferred income tax assets and the fair value of derivative instruments. The estimation of crude oil and natural gas reserves and the related present value of future cash flows involves the use of independent reservoir engineering specialists and numerous inputs and assumptions including forecasted production volumes, forecasted operating, royalty and capital cost assumptions and assumptions around commodity pricing. Inflation and discount rates impacting various items within the Company's financial statements are also subject to management estimation. When estimating the present value of future cash flows, the discount rate implicitly considers the potential impacts, if any, due to climate change factors. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions.

3) ACCOUNTS RECEIVABLE

($ thousands)		September 30, 2022		December 31, 2021
Accrued revenue	$	291,342	$	208,160
Accounts receivable – trade		26,280		23,697
Allowance for doubtful accounts		(3,852)		(3,869)
Total accounts receivable, net of allowance for doubtful accounts	$	313,770	$	227,988

4) PROPERTY, PLANT AND EQUIPMENT ("PP&E")

At September 30, 2022 ($ thousands)		Cost		Accumulated Depletion, Depreciation, and Impairment		Net Book Value
Crude oil and natural gas properties(1)	$	12,915,425	$	(11,496,611)	$	1,418,814
Other capital assets		97,154		(86,126)		11,028
Total PP&E	$	13,012,579	$	(11,582,737)	$	1,429,842

At December 31, 2021 ($ thousands)		Cost		Accumulated Depletion, Depreciation, and Impairment		Net Book Value
Crude oil and natural gas properties(1)	$	13,075,987	$	(11,822,482)	$	1,253,505
Other capital assets		103,355		(89,468)		13,887
Total PP&E	$	13,179,342	$	(11,911,950)	$	1,267,392

(1) All of the Company's unproved properties are included in the full cost pool.

5) IMPAIRMENT

No asset impairment was recorded during the three and nine months ended September 30, 2022 (2021 – nil and $3.4 million in the Canadian cost center, respectively). The primary factors that affect ceiling values include first-day-of-the-month commodity prices, reserves revisions, capital expenditure levels and timing, acquisition and divestment activity, and production levels.

The following table outlines the twelve month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from September 30, 2021 through September 30, 2022:

Period		WTI Crude Oil $/bbl		Edm Light Crude CDN$/bbl		U.S. Henry Hub Gas $/Mcf	Exchange Rate CDN$/US$
Q3 2022	$	92.16	$	113.94	$	6.07	0.79
Q2 2022		85.82		104.78		5.14	0.79
Q1 2022		75.28		90.17		4.11	0.80
Q4 2021		66.55		78.15		3.64	0.80
Q3 2021		57.64		67.27		3.00	0.79

6) ACQUISITIONS & DIVESTMENT

a) Bruin E&P HoldCo, LLC Acquisition

On January 25, 2021, Enerplus Resources (USA) Corporation, an indirect wholly-owned subsidiary of Enerplus entered into a purchase agreement to acquire all of the equity interests of Bruin E&P HoldCo, LLC ("Bruin") for total cash consideration of $465.0 million, subject to certain purchase price adjustments. Bruin was a private company that held crude oil and natural gas interests in certain properties located in the Williston Basin, North Dakota. The effective date of the acquisition was January 1, 2021 and the acquisition was completed on March 10, 2021.

The transaction was accounted for as an acquisition of a business. The purchase price equation was determined following the closing date, during which time the value of the net assets and liabilities acquired was revised as indicated in the agreement and is reflected in the final purchase price equation as follows:

($ thousands)		At March 10, 2021
Consideration		
Purchase Price	$	465,000
Purchase price adjustments		(44,751)
Total consideration	$	420,249
Fair value of identifiable assets and liabilities of Bruin		
Other current assets		1,667
Property, plant and equipment		542,190
Right of use assets		1,892
Accounts payable		(25,257)
Asset retirement obligation		(21,964)
Commodity contract liabilities		(76,387)
Lease liabilities		(1,892)
Total identifiable net assets	$	420,249

b) Dunn County Acquisition

On April 30, 2021, the Company acquired assets in Dunn County, North Dakota from Hess Bakken Investments II, LLC for total cash consideration of $312.0 million, subject to customary purchase price adjustments. After purchase price adjustments, the purchase consideration including capitalized transaction costs was $306.8 million. The transaction was recorded as an asset acquisition.

c) Sleeping Giant and Russian Creek Divestment

On November 2, 2021, the Company completed a disposition of its interests in the Sleeping Giant field in Montana and the Russian Creek area in North Dakota in the Williston Basin, for total cash consideration of $115.0 million, subject to customary purchase price adjustments. After purchase price adjustments and transaction costs, adjusted proceeds were $107.8 million. In addition, Enerplus may receive up to $5.0 million in contingent payments if the WTI oil price averages over $65 per barrel in 2022 and over $60 per barrel in 2023, with amounts payable on January 31, 2023 and January 31, 2024, respectively. The fair value of the contingent payments have been recorded as part of Other Current Assets and Other Long-Term assets.

7) ACCOUNTS PAYABLE

($ thousands)		September 30, 2022		December 31, 2021
Accrued payables	$	160,782	$	106,222
Accounts payable – trade		292,902		260,786
Total accounts payable	$	453,684	$	367,008

8) DEBT

($ thousands)	September 30, 2022	December 31, 2021
Current:		
Senior notes	$ 80,600	$ 100,600
Long-term:		
Bank credit facilities	230,044	397,971
Senior notes	122,600	203,200
Total debt	$ 433,244	$ 701,771

Bank Credit Facilities

During the nine months ended September 30, 2022, Enerplus converted its senior unsecured, covenant-based, $400 million term loan maturing on March 9, 2024 into a revolving bank credit facility with no other amendments. Debt issuance costs were netted against the debt on issuance and are being amortized over the three-year term with $1.2 million of unamortized debt issuance costs remaining at September 30, 2022.

Enerplus also has a senior unsecured, covenant-based, $900 million sustainability linked lending ("SLL") bank credit facility that matures on October 31, 2025. Debt issuance costs in relation to the SLL bank credit facility are being amortized over the four and a half year term with $1.2 million of debt issuance costs remaining unamortized at September 30, 2022.

For the three and nine months ended September 30, 2022, total amortization of debt issuance costs amounted to $0.4 million and $1.1 million, respectively (2021 – $0.4 million and $0.7 million, respectively).

Subsequent to the quarter, on November 3, 2022, Enerplus converted its $400 million revolving bank credit facility to a $365 million SLL bank credit facility, and extended the maturity to October 31, 2025. The $365 million SLL bank credit facility has similar targets to Enerplus' $900 million SLL bank credit facility, which was renewed with $50 million maturing on October 31, 2025, and $850 million maturing on October 31, 2026. There were no other significant amendments or additions to the two agreements' terms or covenants.

Senior Notes

During the three months ended September 30, 2022, Enerplus made a $21.0 million principal repayment on its 2014 senior notes. In addition, during the nine months ended September 30, 2022, Enerplus made its third $59.6 million principal repayment on its 2012 senior notes and a $20.0 million bullet payment. The terms and rates of the Company's outstanding senior notes are provided below:

Issue Date	Interest Payment Dates	Principal Repayment	Coupon Rate	Original Principal ($ thousands)	Remaining Principal ($ thousands)
September 3, 2014	March 3 and Sept 3	4 equal annual installments beginning September 3, 2023	3.79%	$200,000	$84,000
May 15, 2012	May 15 and Nov 15	2 equal annual installments beginning May 15, 2023	4.40%	$355,000	$119,200
				Total carrying value at September 30, 2022	$ 203,200

Capital Management

Enerplus' capital consists of cash and cash equivalents, debt and shareholders' equity. The Company's objective for managing capital is to prioritize balance sheet strength while maintaining flexibility to repay debt, fund sustaining capital, return capital to shareholders or fund future production growth. Capital management measures are useful to investors and securities analysts in analyzing operating and financial performance, leverage, and liquidity. Enerplus' key capital management measures are as follows:

a) Net Debt

Enerplus calculates net debt as current and long-term debt associated with senior notes plus any outstanding bank credit facility balances, minus cash and cash equivalents.

($ thousands)		September 30, 2022		December 31, 2021
Current portion of long-term debt	$	80,600	$	100,600
Long-term debt		352,644		601,171
Total debt	$	433,244	$	701,771
Less: Cash and cash equivalents		(42,185)		(61,348)
Net debt	$	391,059	$	640,423

b) Adjusted funds flow

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 September 30,				Nine months ended September 30,			
($thousands)		2022		2021		2022		2021
Cash flow from/(used in) operating activities	$	409,946	$	182,177	$	856,798	$	321,305
Asset retirement obligation settlements		1,560		1,681		12,704		8,461
Changes in non-cash operating working capital		(55,884)		19,273		45,408		124,190
Adjusted funds flow	$	355,622	$	203,131	$	914,910	$	453,956

c) Net debt to adjusted funds flow ratio

The net debt to adjusted funds flow ratio is calculated as net debt divided by a trailing twelve months of adjusted funds flow.

($thousands)		September 30, 2022		December 31, 2021
Net debt	$	391,059	$	640,423
Trailing adjusted funds flow		1,173,387		712,433
Net debt to adjusted funds flow ratio		0.3x		0.9x

9) ASSET RETIREMENT OBLIGATION (“ARO”)

($ thousands)		September 30, 2022		December 31, 2021
Balance, beginning of year	$	132,814	$	102,325
Change in estimates		27,186		26,586
Property acquisitions and development activity		3,225		1,304
Bruin acquisition (Note 6)		—		21,964
Dunn County acquisition (Note 6)		—		5,880
Divestments (Note 6)		(166)		(13,525)
Settlements		(12,704)		(12,951)
Government assistance		(786)		(4,594)
Accretion expense		5,599		5,825
Balance, end of period	$	155,168	$	132,814

Enerplus has estimated the present value of its ARO to be $155.2 million at September 30, 2022 based on a total undiscounted uninflated liability of $340.6 million (December 31, 2021 – $132.8 million and $303.3 million, respectively).

Enerplus benefited from provincial government assistance to support the clean-up 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 and nine months ended September 30, 2022, Enerplus benefited from $0.3 million and $0.8 million, respectively (2021 – $0.2 million and $2.1 million, respectively), in government assistance, which has been recorded as other income in the Condensed Consolidated Statements of Income/(Loss).

For the nine months ended September 30, 2022, Enerplus recognized $13.1 million as part of other expense in the Condensed Consolidated Statements of Income/(Loss) to fund abandonment and reclamation obligation requirements on previously disposed of assets (2021 – nil).

10) LEASES

The Company has entered into various lease contracts related to office space, drilling rig commitments, vehicles and other equipment. Leases are entered into and exited in coordination with specific business requirements which include the assessment of the appropriate durations for the related leased assets. Short-term leases with a lease term of 12 months or less are not recorded on the Condensed Consolidated Balance Sheets. Such items are charged to operating expenses or general and administrative expenses, as appropriate, in the Condensed Consolidated Statements of Income/(Loss), unless the costs are included in the carrying amount of another asset in accordance with U.S. GAAP.

($ thousands)	September 30, 2022	December 31, 2021
Assets		
Operating right-of-use assets	$ 20,490	$ 26,118
Liabilities		
Current operating lease liabilities	$ 11,342	$ 10,618
Non-current operating lease liabilities	11,619	18,265
Total lease liabilities	$ 22,961	$ 28,883
Weighted average remaining lease term (years)		
Operating leases	2.6	3.3
Weighted average discount rate		
Operating leases	3.3%	3.4%

The Company's lease contract expenditures/(income) for the three and nine months ended September 30, 2022 and 2021 are as follows:

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2022	2021	2022	2021
Operating lease cost	$ 3,016	$ 2,830	$ 8,863	$ 8,465
Variable lease cost	887	171	3,188	466
Short-term lease cost	2,210	449	4,781	1,754
Sublease income	(232)	(276)	(824)	(749)
Total	$ 5,881	$ 3,174	$ 16,008	$ 9,936

Variable lease payments are determined through analysis of day rate fees under applicable rig contracts. The amounts in the table above are recorded as part of general and administrative or operating expenses or property, plant, and equipment depending on the nature of the contract to which they relate. Although Enerplus has various leases containing extensions and/or termination options, none were determined to be reasonably certain to be exercised. As a result, none of these options are recognized as part of the ROU assets or lease liabilities at September 30, 2022 or December 31, 2021.

Maturities of lease liabilities, all of which are classified as operating leases at September 30, 2022 are as follows:

($ thousands)		Operating Leases
2022	$	3,075
2023		11,590
2024		6,174
2025		1,120
2026		966
After 2026		1,153
Total lease payments	$	24,078
Less imputed interest		(1,117)
Total discounted lease payments	$	22,961
Current portion of lease liabilities	$	11,342
Non-current portion of lease liabilities	$	11,619

Supplemental information related to leases is as follows:

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2022	2021	2022	2021
Cash amounts paid to settle lease liabilities:				
Operating cash flow used for operating leases	$ 1,937	$ 2,639	$ 7,744	$ 8,710
Right-of-use assets obtained/(terminated) in exchange for lease liabilities:				
Operating leases	$ 1,211	$ 747	$ 3,525	$ 9,404

11) CRUDE OIL AND NATURAL GAS SALES

Crude oil and natural gas revenue by country and by product for the three and nine months ended September 30, 2022 and 2021 are as follows:

Three months ended September 30, 2022 ($ thousands)	Total revenue	Crude oil[1]	Natural gas[1]	Natural gas liquids[1]	Other[2]
United States	$ 626,746	$ 456,385	$ 139,575	$ 30,784	$ 2
Canada	36,786	32,684	2,593	1,348	161
Total	$ 663,532	$ 489,069	$ 142,168	$ 32,132	$ 163

Three months ended September 30, 2021 ($ thousands)	Total revenue	Crude oil[1]	Natural gas[1]	Natural gas liquids[1]	Other[2]
United States	$ 387,665	$ 308,142	$ 57,238	$ 22,280	$ 5
Canada	33,468	29,406	2,770	1,089	203
Total	$ 421,133	$ 337,548	$ 60,008	$ 23,369	$ 208

Nine months ended September 30, 2022 ($ thousands)	Total revenue	Crude oil[1]	Natural gas[1]	Natural gas liquids[1]	Other[2]
United States	$ 1,677,253	$ 1,247,816	$ 347,043	$ 82,384	$ 10
Canada	127,448	112,680	9,855	4,457	456
Total	$ 1,804,701	$ 1,360,496	$ 356,898	$ 86,841	$ 466

Nine months ended September 30, 2021 ($ thousands)	Total revenue	Crude oil[1]	Natural gas[1]	Natural gas liquids[1]	Other[2]
United States	$ 892,056	$ 703,818	$ 141,054	$ 47,165	$ 19
Canada	90,889	79,532	7,693	3,087	577
Total	$ 982,945	$ 783,350	$ 148,747	$ 50,252	$ 596

(1) U.S. sales of crude oil and natural gas relate primarily to the Company's North Dakota and Marcellus properties, respectively. Canadian crude oil sales relate primarily to the Company's waterflood properties.
(2) Includes third party processing income.

12) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	Three months ended September 30, 2022	Three months ended September 30, 2021	Nine months ended September 30, 2022	Nine months ended September 30, 2021
General and administrative expense[1]	$ 10,797	$ 8,463	$ 31,191	$ 27,484
Share-based compensation expense	4,948	3,938	16,822	7,892
General and administrative expense	$ 15,745	$ 12,401	$ 48,013	$ 35,376

(1) Includes a non-cash lease credit of $100 and $294, respectively for the three and nine months ended September 30, 2022 (2021 – credit of $92 and $273, respectively).

13) FOREIGN EXCHANGE

($ thousands)	Three months ended September 30, 2022	Three months ended September 30, 2021	Nine months ended September 30, 2022	Nine months ended September 30, 2021
Realized:				
Foreign exchange (gain)/loss	$ 68	$ 499	$ (41)	$ 2,867
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company	(956)	(288)	(1,071)	(1,907)
Unrealized:				
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company	16,997	(14,234)	14,876	(7,229)
Foreign exchange (gain)/loss	$ 16,109	$ (14,023)	$ 13,764	$ (6,269)

14) INCOME TAXES

($ thousands)	Three months ended September 30, 2022	Three months ended September 30, 2021	Nine months ended September 30, 2022	Nine months ended September 30, 2021
Current tax				
United States	$ 7,929	$ (926)	$ 24,929	$ 2,489
Canada	—	—	—	—
Current tax expense/(recovery)	7,929	(926)	24,929	2,489
Deferred tax				
United States	$ 43,328	$ 41,583	$ 173,694	$ 85,903
Canada	49,821	(10,182)	938	(54,854)
Deferred tax expense/(recovery)	93,149	31,401	174,632	31,049
Income tax expense/(recovery)	$ 101,078	$ 30,475	$ 199,561	$ 33,538

The difference between the expected income taxes based on the statutory income tax rate and the effective income taxes for the current and prior period is impacted by expected annual earnings, recognition or reversal of valuation allowance, foreign rate differentials for foreign operations, statutory and other rate differentials, non-taxable portions of capital gain and losses, and share-based compensation.

The Company's deferred income tax asset recorded in Canada is $197.4 million offset by a deferred income tax liability in the U.S. of $11.1 million at September 30, 2022 (December 31, 2021 – $380.9 million net asset).

15) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized unlimited number of common shares issued: (thousands)	**Nine months ended September 30, 2022** Shares	Amount	**Year ended December 31, 2021** Shares	Amount
Balance, beginning of year	243,852	$ 3,094,061	222,548	$ 3,113,829
Issued/(Purchased) for cash:				
Issue of shares (net of tax effected issue costs)	—	—	33,062	99,516
Purchase of common shares under Normal Course Issuer Bid	(18,126)	(175,803)	(12,898)	(128,686)
Non-cash:				
Share-based compensation – treasury settled(1)	1,240	7,959	1,140	9,402
Balance, end of period	226,966	$ 2,926,217	243,852	$ 3,094,061

(1) The amount of shares issued on long-term incentive settlement is net of employee withholding taxes.

Dividends declared to shareholders for the three and nine months ended September 30, 2022 were $11.5 million and $29.4 million, respectively (2021 – $7.9 million and $22.6 million, respectively). Subsequent to the quarter, the Board of Directors approved a 10% increase to the dividend to $0.055 per share to be effective for the December 2022 payment.

On August 16, 2022, Enerplus renewed its Normal Course Issuer Bid ("NCIB") to purchase up to 10% of the public float (within the meaning under Toronto Stock Exchange rules) during a 12-month period. Enerplus completed its previous NCIB in July 2022.

During the three months ended September 30, 2022, 7,913,168 common shares were repurchased and cancelled under the NCIB at an average price of $14.13 per share, for total consideration of $111.8 million. Of the amount paid, $75.4 million was charged to share capital and $36.4 million was credited to accumulated deficit. During the nine months ended September 30, 2022, 18,126,090 common shares were repurchased and cancelled under the NCIB at an average price of $13.35 per share, for total consideration of $241.9 million. Of the amount paid, $175.8 million was charged to share capital and $66.1 million was credited to accumulated deficit.

During the three and nine months ended September 30, 2021, 1,657,650 common shares were repurchased and cancelled under the NCIB at an average price of $6.12 per share, for total consideration of $10.1 million. Of the amount paid, $16.5 million was charged to share capital and $6.4 million was credited to accumulated deficit.

Subsequent to September 30, 2022 and up to and including November 2, 2022, the Company repurchased 2,729,590 common shares under the NCIB at an average price of $16.00 per share, for total consideration of $43.7 million.

b) Share-based Compensation

The following table summarizes Enerplus' share-based compensation expense, which is included in General and Administrative expense on the Condensed Consolidated Statements of Income/(Loss):

($ thousands)	**Three months ended September 30,** 2022	2021	**Nine months ended September 30,** 2022	2021
Cash:				
Long-term incentive plans expense	$ 1,183	$ 825	$ 3,577	$ 4,842
Non-Cash:				
Long-term incentive plans expense	3,765	3,369	14,253	4,333
Equity swap gain	—	(256)	(1,008)	(1,283)
Share-based compensation expense	$ 4,948	$ 3,938	$ 16,822	$ 7,892

Long-term Incentive ("LTI") Plans

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU"), Director Deferred Share Unit ("DSU") and Director RSU ("DRSU") activity for the nine months ended September 30, 2022:

	Cash-settled LTI plans	Equity-settled LTI plans		Total
(thousands of units)	Director Plans	PSU[1]	RSU	
Balance, beginning of year	589	3,981	3,065	7,635
Granted	86	796	825	1,707
Vested	(45)	(827)	(1,300)	(2,172)
Forfeited	—	(38)	(116)	(154)
Balance, end of period	630	3,912	2,474	7,016

(1) Based on underlying awards before any effect of the performance multiplier.

Cash-settled LTI Plans

For the three and nine months ended September 30, 2022, the Company recorded a cash share-based compensation expense of $1.2 million and $3.6 million, respectively (2021 – $0.8 million and $4.8 million, respectively).

As of September 30, 2022, a liability of $8.9 million (December 31, 2021 – $6.3 million) with respect to the Director DSU and DRSU plans has been recorded to Accounts Payable on the Condensed Consolidated Balance Sheets.

Equity-settled LTI Plans

The following table summarizes the cumulative share-based compensation expense recognized to-date, which is recorded as Paid-in Capital on the Condensed Consolidated Balance Sheets. Unrecognized amounts will be recorded to non-cash share-based compensation expense over the remaining vesting terms.

At September 30, 2022 ($ thousands, except for years)	PSU[1]	RSU	Total
Cumulative recognized share-based compensation expense	$ 14,145	$ 9,169	$ 23,314
Unrecognized share-based compensation expense	9,046	6,281	15,327
Fair value	$ 23,191	$ 15,450	$ 38,641
Weighted-average remaining contractual term (years)	1.3	1.0	

(1) Includes estimated performance multipliers.

The Company directly withholds shares on PSU and RSU settlements for tax-withholding purposes. For the three and nine months ended September 30, 2022, nil and $11.6 million, respectively (2021 – nil and $3.6 million, respectively) in cash withholding taxes were paid.

c) Basic and Diluted Net Income/(Loss) Per Share

Net income/(loss) per share has been determined as follows:

	Three months ended September 30,		Nine months ended September 30,	
(thousands, except per share amounts)	2022	2021	2022	2021
Net income/(loss)	$ 305,945	$ 98,112	$ 583,594	$ 57,528
Weighted average shares outstanding – Basic	231,565	256,345	237,835	252,432
Dilutive impact of share-based compensation	7,571	4,486	7,568	4,468
Weighted average shares outstanding – Diluted	239,136	260,831	245,403	256,900
Net income/(loss) per share				
Basic	$ 1.32	$ 0.38	$ 2.47	$ 0.22
Diluted	$ 1.28	$ 0.38	$ 2.40	$ 0.22

16) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At September 30, 2022, the carrying value of cash and cash equivalents, accounts receivable, and accounts payable approximated their fair value due to the short-term nature of these instruments. The fair values of the bank credit facilities approximate their carrying values as they bear interest at floating rates and the credit spread approximates current market rates.

At September 30, 2022, the senior notes had a carrying value of $203.2 million and a fair value of $189.2 million (December 31, 2021 – $303.8 million and $304.1 million, respectively). The fair value of the senior notes is estimated based on the amount that Enerplus would have to pay a third party to assume the debt, including the credit spread for the difference between the issue rate and the period end market rate. The period end market rate is estimated by comparing the debt to new issuances (secured or unsecured) and secondary trades of similar size and credit statistics for both public and private debt.

The fair value of derivative contracts, senior notes and bank credit facilities are considered level 2 fair value measurements. There were no transfers between fair value hierarchy levels during the period.

b) Derivative Financial Instruments

The derivative financial assets and liabilities on the Condensed Consolidated Balance Sheets result from recording derivative financial instruments at fair value. At September 30, 2022, Enerplus has commodity and contingent consideration contracts. See Note 6 regarding the contingent consideration contract.

The following table summarizes the income statement change in fair value for the three and nine months ended September 30, 2022 and 2021:

	Three months ended September 30,		Nine months ended September 30,		Income Statement
Gain/(Loss) ($ thousands)	**2022**	**2021**	**2022**	**2021**	**Presentation**
Equity Swaps	$ —	$ 256	$ 1,008	$ 1,283	G&A
Commodity Contracts:					
Crude oil	125,978	3,250	98,785	(158,259)	Commodity derivative
Natural gas	19,502	(11,469)	3,630	(21,625)	instruments
Total Unrealized Gain/(Loss)	$ 145,480	$ (7,963)	$ 103,423	$ (178,601)	

The following table summarizes the effect of Enerplus' commodity contracts on the Condensed Consolidated Statements of Income/(Loss):

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2022**	**2021**	**2022**	**2021**
Unrealized change in fair value gain/(loss)	$ 145,480	$ (8,219)	$ 102,415	$ (179,884)
Net realized gain/(loss)	(88,485)	(49,228)	(299,783)	(95,648)
Commodity contracts gain/(loss)	$ 56,995	$ (57,447)	$ (197,368)	$ (275,532)

The following table summarizes the presentation of fair values at the respective period ends:

	September 30, 2022				December 31, 2021		
	Assets		Liabilities		Assets	Liabilities	
($ thousands)	Current	Long-term	Current	Long-term	Current	Current	Long-term
Equity Swaps	$ —	$ —	$ —	$ —	$ —	$ 969	$ —
Commodity Contracts:							
Crude oil	7,088	3,407	38,025	2,181	1,771	141,364	7,098
Natural gas	8,091	—	1,429	—	3,897	867	—
Total	$ 15,179	$ 3,407	$ 39,454	$ 2,181	$ 5,668	$ 143,200	$ 7,098

The fair value of commodity contracts and the equity swaps is estimated based on commodity and option pricing models that incorporate various factors including forecasted commodity prices, volatility and the credit risk of the entities party to the contract. Changes and variability in commodity prices over the term of the contracts can result in material differences between the estimated fair value at a point in time and the actual settlement amounts.

On March 10, 2021, the outstanding crude oil commodity contracts acquired with the Bruin acquisition were recorded at fair value. Realized and unrealized gains and losses on the acquired contracts are recognized in the Condensed Consolidated Statement of Income/(Loss) and the Condensed Consolidated Balance Sheets to reflect changes in crude oil prices from the closing date of the Bruin acquisition.

At September 30, 2022, the fair value of Enerplus' commodity contracts totaled a net liability of $23.0 million (December 31, 2021 – $143.7 million). Of this total net liability, $13.2 million (December 31, 2021 – $40.2 million) related to Bruin contracts, with $4.7 million (December 31, 2021 – $22.8 million) remaining from the original $76.4 million liability acquired from Bruin on March 10, 2021.

c) Risk Management

In the normal course of operations, Enerplus is exposed to various market risks, including commodity prices, foreign exchange, interest rates, equity prices, credit risk, liquidity risk, and the risks associated with environmental/climate change risk, social and governance regulation, and compliance.

i) Market Risk

Market risk is comprised of commodity price, foreign exchange, interest rate and equity price risk.

Commodity Price Risk:

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes. The following tables summarize Enerplus' price risk management positions at November 3, 2022:

Crude Oil Instruments:

Instrument Type(1)(2)	Oct 1, 2022 - Dec 31, 2022	
	bbls/day	US$/bbl
WTI Purchased Put	17,000	50.00
WTI Sold Put	17,000	40.00
WTI Sold Call	17,000	57.91
WTI Sold Swap(3)	1,834	42.65
WTI Purchased Swap	1,834	64.55

	Jan 1, 2023 - Jun 30, 2023		Jul 1, 2023 - Oct 31, 2023		Nov 1, 2023 - Dec 31, 2023	
	bbls/day	US$/bbl	bbls/day	US$/bbl	bbls/day	US$/bbl
WTI Purchased Put	15,000	79.33	5,000	85.00	5,000	85.00
WTI Sold Put	15,000	61.67	5,000	65.00	5,000	65.00
WTI Sold Call	15,000	114.31	5,000	128.16	5,000	128.16
Brent – WTI Spread	10,000	5.47	10,000	5.47	10,000	5.47
WTI Purchased Swap	250	64.85	250	64.85	—	—
WTI Sold Swap(3)	250	42.10	250	42.10	—	—
WTI Purchased Put(3)	2,000	5.00	2,000	5.00	2,000	5.00
WTI Sold Call(3)	2,000	75.00	2,000	75.00	2,000	75.00

(1) The total average deferred premium spent on the Company's outstanding crude oil contracts is $1.50/bbl from October 1, 2022 – December 31, 2022 and $1.25/bbl from January 1, 2023 – December 31, 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 E&P Holdco, LLC's outstanding crude oil contracts were recorded at a fair value liability of $76.4 million. At September 30, 2022, the remaining liability was $4.7 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.

Natural Gas Instruments:

Instrument Type[(1)]	Oct 1, 2022 – Oct 31, 2022		Nov 1, 2022 – Mar 31, 2023		Apr 1, 2023 – Oct 31, 2023	
	MMcf/day	US$/Mcf	MMcf/day	US$/Mcf	MMcf/day	US$/Mcf
NYMEX Swap	40.0	3.40	—	—	—	—
NYMEX Purchased Put	60.0	3.77	120.0	6.27	50.0	4.05
NYMEX Sold Call	60.0	4.50	120.0	18.17	50.0	7.00

(1) Transactions with a common term have been aggregated and presented at weighted average prices/Mcf.

Foreign Exchange Risk & Net Investment Hedge:

Enerplus is exposed to foreign exchange risk as it relates to certain activity transacted in Canadian or United States dollars. Enerplus has a U.S. dollar reporting currency, however Enerplus' parent company has a Canadian functional currency. Activity in the Canadian parent company that is transacted in U.S. dollars results in realized and unrealized foreign exchange gains and losses and is recorded on the Condensed Consolidated Statements of Income/(Loss).

Enerplus may designate certain U.S. dollar denominated debt held in the parent entity as a hedge of its net investment in its U.S. subsidiary, which has a U.S. dollar functional currency. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in Other Comprehensive Income/(Loss), net of tax, and are limited by the cumulative translation gain or loss on the net investment in the foreign subsidiary. At September 30, 2022, $203.2 million of senior notes and $230.0 million drawn on the bank credit facilities were designated as net investment hedges (December 31, 2021 – $303.8 million of the senior notes and $400 million of the term loan, respectively). For the three and nine months ended September 30, 2022, Other Comprehensive Income/(Loss) included an unrealized loss of $24.3 million and $33.0 million, respectively on Enerplus' U.S. denominated senior notes and bank credit facilities (2021 – $13.7 million loss and $2.2 million gain, respectively).

Interest Rate Risk:

The Company's senior notes bear interest at fixed rates while the bank credit facilities bear interest at floating rates. At September 30, 2022, approximately 47% of Enerplus' debt was based on fixed interest rates and 53% on floating interest rates (December 31, 2021 – 43% fixed and 57% floating), with weighted average interest rates of 4.2% and 2.5%, respectively. At September 30, 2022, Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 15. The Company may enter into various equity swaps to fix the future settlement cost on a portion of its cash settled LTI plans. At September 30, 2022, Enerplus did not have any equity swaps outstanding.

ii) Credit Risk

Credit risk represents the financial loss Enerplus would experience due to the potential non-performance of counterparties to its financial instruments. Enerplus is exposed to credit risk mainly through its joint venture, marketing and financial counterparty receivables. Enerplus has appropriate policies and procedures in place to manage its credit risk; however, given the volatility in commodity prices, Enerplus is subject to an increased risk of financial loss due to non-performance or insolvency of its counterparties.

Enerplus mitigates credit risk through credit management techniques, including conducting financial assessments to establish and monitor counterparties' credit worthiness, setting exposure limits, monitoring exposures against these limits and obtaining financial assurances such as letters of credit, parental guarantees, or third party credit insurance where warranted. Enerplus monitors and manages its concentration of counterparty credit risk on an ongoing basis.

The Company's maximum credit exposure consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At September 30, 2022, approximately 91% of Enerplus' marketing receivables were with companies considered investment grade (December 31, 2021 – 83%).

Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts of future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at September 30, 2022 was $3.9 million (December 31, 2021 – $3.9 million).

iii) Liquidity Risk & Capital Management

Liquidity risk represents the risk that Enerplus will be unable to meet its financial obligations as they become due. Enerplus mitigates liquidity risk through actively managing its capital, which it defines as debt (net of cash and cash equivalents) and shareholders' capital. Enerplus' objective is to provide adequate short and longer term liquidity while maintaining a flexible capital structure to sustain the future development of its business. Enerplus strives to balance the portion of debt and equity in its capital structure given its current crude oil and natural gas assets and planned investment opportunities.

Management monitors a number of key variables with respect to its capital structure, including debt levels, capital spending plans, dividends, share repurchases, access to capital markets, as well as acquisition and divestment activity.

At September 30, 2022, Enerplus was in full compliance with all covenants under the bank credit facilities and outstanding senior notes. If the Company breaches or anticipates breaching its covenants, the Company may be required to repay, refinance, or renegotiate the terms of the debt.

iv) Climate Change Risk

Enerplus is exposed to climate change risks through changing regulation, potential access to capital, capital spending plans and the impact of climate related events on the Company's financial position. The Company did not recognize amounts in respect of climate change risk in the Condensed Consolidated Financial Statements at and for the three and nine months ended September 30, 2022 as there have been no material changes since management's risk assessment at December 31, 2021.

17) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2022	2021	2022	2021
Accounts receivable	$ 73,456	$ (31,861)	$ (86,627)	$ (152,635)
Other assets	(2,575)	(6,361)	2,217	(5,093)
Accounts payable – operating	(14,997)	18,949	39,002	33,538
Non-cash operating activities	$ 55,884	$ (19,273)	$ (45,408)	$ (124,190)

b) Changes in Non-Cash Financing Working Capital

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2022	2021	2022	2021
Dividends payable	$ —	$ —	$ —	$ (1,749)
Non-cash financing activities	$ —	$ —	$ —	$ (1,749)

c) Changes in Non-Cash Investing Working Capital

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2022	2021	2022	2021
Accounts payable – investing(1)	$ (6,750)	$ (13,815)	$ 35,540	$ 29,029

(1) Relates to changes in accounts payable for capital and office expenditures and included in capital and office expenditures on the Condensed Consolidated Statements of Cash Flows.

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2022	2021	2022	2021
Settlement on divestment(1)	$ —	$ —	$ 13,053	$ —

(1) Relates to funding abandonment and reclamation obligation requirements on previously disposed assets. Refer to Note 9.

d) Cash Income Taxes and Interest Payments

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2022	2021	2022	2021
Income taxes paid/(received)	$ 17,657	$ 753	$ 20,271	$ 4,171
Interest paid	$ 5,056	$ 6,221	$ 17,455	$ 18,585

e) Other

During the three months ended September 30, 2021, Enerplus received a $4.6 million distribution associated with a privately held investment. This distribution was recorded within Transaction costs and other expense/(income) on the Consolidated Statements of Income/(Loss), and reflected as an investing activity in the Condensed Consolidated Statements of Cash Flows.

18) SUBSEQUENT EVENTS

During the quarter, the Company announced it had entered into a definitive agreement with Journey Energy Inc. ("Journey") to sell certain Canadian assets ("the Assets") located in Alberta for total consideration of CDN$140 million, prior to closing adjustments. The total consideration comprises cash of CDN$81 million, 3.0 million common shares in Journey, and a CDN$45 million monthly amortizing, interest-bearing loan which Enerplus will provide to Journey that is secured by certain of the Assets and which must be repaid in full by October 31, 2024. The divestment closed on October 31, 2022.

Subsequent to the quarter, on November 2, 2022, the Company announced it had entered into a definitive agreement with Surge Energy Inc. (“Surge”) to sell substantially all of its remaining Canadian assets located in Alberta and Saskatchewan for total consideration of CDN$245 million, prior to closing adjustments. The total consideration comprises cash of CDN$210 million and CDN$35 million in common shares of Surge. The divestment is expected to close in December 2022.

BOARD OF DIRECTORS

Hilary A. Foulkes(1)(2)
Corporate Director
Calgary, Alberta

Sherri A. Brillon(5)(9)
Corporate Director
Calgary, Alberta

Judith D. Buie(3)(5)(7)
Corporate Director
Houston, Texas

Karen E. Clarke-Whistler(3)(7)(9)
Corporate Director
Toronto, Ontario

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

Robert B. Hodgins(4)(9)
Corporate Director
Calgary, Alberta

Mark A. Houser(5)(7)(9)
Corporate Director
Houston, Texas

Susan M. MacKenzie(7)(10)
Corporate Director
Calgary, Alberta

Jeffrey W. Sheets(6)(9)
Corporate Director
Houston, Texas

Sheldon B. Steeves(5)(8)
Corporate Director
Calgary, Alberta

(1) Chair of the Board
(2) *Ex-Officio* member of all Committees of the Board
(3) Member of the Corporate Governance & Nominating Committee
(4) Chair of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chair of the Audit & Risk Management Committee
(7) Member of the Reserves, Safety & Social Responsibility Committee
(8) Chair of the Reserves, Safety & Social Responsibility Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chair of the Compensation & Human Resources Committee

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas
President & Chief Executive Officer

Wade D. Hutchings
Senior Vice President & Chief Operating Officer

Jodine J. Jenson Labrie
Senior Vice President & Chief Financial Officer

Garth R. Doll
Vice President, Marketing

Terry S. Eichinger
Vice President, Drilling, Completions & Operations Support

Nathan D. Fisher
Vice President, United States Business Unit

Daniel J. Fitzgerald
Vice President, Business Development

John E. Hoffman
Vice President, Digital Technology & Corporate Sustainability

David A. McCoy
Vice President, General Counsel & Corporate Secretary

Shaina B. Morihira
Vice President, Finance

Pamela A. Ramotowski
Vice President, People & Culture

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION

Enerplus Resources (USA) Corporation

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ABBREVIATIONS

bbl(s)/day	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
Bcf	billion cubic feet
BOE	barrels of oil equivalent
Brent	crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $U.S. dollars
DAPL	Dakota Access Pipeline
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMcf	million cubic feet
MMBOE	million barrels of oil equivalent
MSW	Mixed Sweet Blend at Edmonton, Alberta, the benchmark for Canadian light sweet crude oil pricing
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange, the benchmark for North American natural gas pricing
Transco Leidy	Price benchmark for Marcellus natural gas delivered into the Transco pipeline system between Hunterdon County, New Jersey and connections east of the Leidy storage facility in Clinton and Potter Counties in Pennsylvania
Transco Z6 Non-New York	Price benchmark for Marcellus natural gas delivered into the Transco pipeline system from the start of zone 6 at the Virginia-Maryland border to the Linden, New Jersey, compressor station and on the 24-inch pipeline to the Wharton, Pennsylvania, station
U.S. GAAP	accounting principles generally accepted in the United States of America
WCS	Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

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