enerPLUS

THIRD QUARTER REPORT

9 months ended September 30, 2023

SELECTED FINANCIAL RESULTS	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Financial (US$, thousands, except ratios)				
Net Income/(Loss)	$127,655	$305,945	$339,374	$583,594
Adjusted Net Income[1]	137,184	207,913	362,317	525,992
Cash Flow from Operating Activities	212,245	409,946	640,244	856,798
Adjusted Funds Flow	263,684	355,622	720,717	914,910
Dividends to Shareholders - Declared	12,612	11,516	36,361	29,374
Net Debt	212,072	391,059	212,072	391,059
Capital Spending	121,354	114,459	440,943	346,357
Property and Land Acquisitions	2,275	16,252	5,661	19,662
Property and Land Divestments	1,563	4,214	1,702	19,386
Net Debt to Adjusted Funds Flow Ratio	0.2x	0.3x	0.2x	0.3x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ 0.61	$ 1.32	$ 1.59	$ 2.47
Net Income/(Loss) - Diluted	0.59	1.28	1.54	2.40
Weighted Average Number of Shares Outstanding (000's) - Basic	210,337	231,565	213,621	237,835
Weighted Average Number of Shares Outstanding (000's) - Diluted	216,857	239,136	220,093	245,403
Selected Financial Results per BOE[2][3]				
Crude Oil & Natural Gas Sales[4]	$ 48.65	$ 66.90	$ 45.44	$ 67.38
Commodity Derivative Instruments	0.56	(8.92)	1.99	(11.19)
Operating Expenses	(10.17)	(10.47)	(10.32)	(10.10)
Transportation Costs	(3.87)	(4.16)	(4.04)	(4.29)
Production Taxes	(4.21)	(4.86)	(3.65)	(4.76)
General and Administrative Expenses	(1.27)	(1.10)	(1.31)	(1.18)
Cash Share-Based Compensation	(0.20)	(0.12)	(0.04)	(0.13)
Interest, Foreign Exchange and Other Expenses	(0.40)	(0.61)	(0.36)	(0.64)
Current Income Tax Expense	(1.32)	(0.80)	(1.00)	(0.93)
Adjusted Funds Flow	$ 27.77	$ 35.86	$ 26.71	$ 34.16

SELECTED OPERATING RESULTS	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Average Daily Production[3]				
Crude Oil (bbls/day)	54,195	57,482	49,690	51,146
Natural Gas Liquids (bbls/day)	12,430	10,900	10,871	9,319
Natural Gas (Mcf/day)	219,401	236,558	229,591	225,845
Total (BOE/day)	103,192	107,808	98,826	98,106
% Crude Oil and Natural Gas Liquids	65%	63%	61%	62%
Average Selling Price[3][4]				
Crude Oil (per bbl)	$ 82.66	$ 92.48	$ 77.50	$ 97.44
Natural Gas Liquids (per bbl)	19.21	32.04	18.36	34.13
Natural Gas (per Mcf)	1.37	6.53	1.91	5.79
Net Wells Drilled	12.9	9.0	50.2	40.2

(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, 2023	2022	Nine months ended September 30, 2023	2022
WTI Crude Oil ($/bbl)	$ 82.26	$ 91.56	$ 77.39	$ 98.09
Brent (ICE) Crude Oil ($/bbl)	85.95	97.81	82.06	102.33
Propane – Conway ($/bbl)	27.98	44.73	29.56	49.98
NYMEX Natural Gas – Last Day ($/Mcf)	2.55	8.20	2.69	6.77
CDN/US Average Exchange Rate	0.74	0.77	0.74	0.78

Share Trading Summary For the three months ended September 30, 2023	U.S.(1) – ERF (US$)	CDN(2) – ERF (CDN$)
High	$ 18.00	$ 24.32
Low	$ 13.80	$ 18.43
Close	$ 17.63	$ 23.90

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

2023 Dividends Declared per Share	US$	CDN$(1)
First Quarter Total	$ 0.055	$ 0.076
Second Quarter Total	$ 0.055	$ 0.074
Third Quarter Total	$ 0.060	$ 0.082
Total Year to Date	$ 0.170	$ 0.232

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

NEWS RELEASE

HIGHLIGHTS

- Third quarter total production was 103,192 BOE per day (up 8% from the prior quarter) including liquids production of 66,625 barrels per day (up 14% from the prior quarter)
- Adjusted funds flow was $263.7 million in the third quarter, which exceeded capital spending of $121.4 million, generating free cash flow[1] of $142.3 million
- Total return of capital to shareholders during the third quarter was $67.7 million (inclusive of share repurchases and dividends), with $200.8 million returned through the first three quarters of 2023
- On track to return approximately 70% of full-year 2023 free cash flow to shareholders which is expected to result in fourth quarter return of capital of approximately $100 million, based on the current commodity price environment. Enerplus has repurchased $41 million of stock in the fourth quarter through November 1, with additional repurchases planned
- 2023 total production and liquids production guidance was increased by 2,000 BOE per day and 1,000 barrels per day at the midpoint, respectively, due to continued strong operational performance
- 2023 capital spending guidance was narrowed to $520 to $540 million (from the previous range of $510 to $550 million)
- Enerplus expects to exceed its 2030 scope 1 and 2 greenhouse gas (“GHG”) emissions intensity reduction target this year, representing an approximate 40% reduction from the 2021 baseline (and 55% from 2019)

“Enerplus’ third quarter results demonstrate our consistent operational execution and the capital efficient well productivity from our high-quality Bakken asset,” said Ian C. Dundas, President and CEO. “We expect a solid finish to the year with annual production growth in North Dakota tracking 9%, capital spending on budget, and a robust free cash flow profile that supports an increase in the pace of share repurchases in the fourth quarter.”

THIRD QUARTER SUMMARY

Production in the third quarter of 2023 was 103,192 BOE per day, an increase of 8% compared to the prior quarter and 4% lower than the same period a year ago. Crude oil and natural gas liquids production in the third quarter of 2023 was 66,625 barrels per day, an increase of 14% compared to the prior quarter and 3% lower than the same period a year ago. Production increased from the prior quarter primarily due to strong well productivity and operational execution in North Dakota. Production was lower compared to the prior year period as a result of the sale of substantially all of Enerplus’ Canadian assets in the fourth quarter of 2022 and limited capital activity in the Marcellus in 2023.

Enerplus reported third quarter 2023 net income of $127.7 million, or $0.61 per share (basic), compared to net income of $305.9 million, or $1.32 per share (basic), in the same period in 2022. Adjusted net income(1) for the third quarter of 2023 was $137.2 million, or $0.65 per share (basic), compared to $207.9 million, or $0.90 per share (basic), during the same period in 2022. Net income and adjusted net income were lower compared to the prior year period primarily due to lower realized commodity prices and production during the third quarter of 2023.

Enerplus’ third quarter 2023 realized Bakken crude oil price differential was $0.20 per barrel above WTI, compared to $2.41 per barrel above WTI in the third quarter of 2022. Bakken crude oil prices have weakened in the fourth quarter due to increased basin production and lower seasonal refinery demand resulting from planned maintenance outages. Consequently, Enerplus expects its 2023 realized Bakken crude oil price differential to average $0.25 per barrel below WTI, compared to at par with WTI previously.

The Company’s realized Marcellus natural gas price differential widened to $1.24 per Mcf below NYMEX during the third quarter of 2023, compared to $0.99 per Mcf below NYMEX in the third quarter of 2022. As a result of the weaker pricing, Enerplus has revised its full-year 2023 Marcellus natural gas price differential to $0.85 per Mcf below NYMEX, from $0.75 per Mcf below NYMEX previously.

In the third quarter of 2023, Enerplus’ operating expenses were $10.17 per BOE, compared to $10.47 per BOE during the third quarter of 2022. The Company continues to expect operating expenses in the fourth quarter to increase compared to the third quarter due to planned workover activity. Full-year operating expenses are tracking the lower end of the previous guidance range. As a result, Enerplus has revised its full-year 2023 operating expense guidance to $10.75–$11.00 per BOE, from $10.75–$11.50 per BOE.

Capital spending totaled $121.4 million in the third quarter of 2023.

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

Net debt was $212.1 million at September 30, 2023 compared to $199.6 million at June 30, 2023. The increase in net debt was primarily due to the non-cash operating and investing working capital deficit decreasing by approximately $85 million. A portion of this is expected to reverse in the fourth quarter of 2023.

OPERATIONS

North Dakota production averaged 77,702 BOE per day during the third quarter of 2023, an increase of 13% compared to the prior quarter and 6% compared to the same period a year ago. Enerplus drilled 15 gross operated wells (80% working interest) during the third quarter and brought 19 operated wells (91% working interest) on production. The wells were brought on production across three pads in Fort Berthold Indian Reservation and one pad in Williams County.

Marcellus production averaged 145 MMcf per day during the third quarter of 2023, a decrease of 12% compared to the same period in 2022 and 6% lower than the prior quarter. The reduced Marcellus production reflects the limited capital activity directed to the asset in 2023 following the lower natural gas price environment compared to 2022.

RETURN OF CAPITAL TO SHAREHOLDERS

In the third quarter, Enerplus returned $67.7 million to shareholders through the repurchase of 3.3 million common shares under its normal course issuer bid ("NCIB") at an average price of $16.85 per share and $12.6 million in dividends. During the nine months ended September 30, 2023, a total of $200.8 million was returned to shareholders through dividends and share repurchases.

Subsequent to September 30, 2023 and up to November 1, 2023, Enerplus repurchased 2.5 million common shares under its NCIB at an average price of $16.65 per share, for total consideration of $40.9 million.

The Board of Directors approved a fourth quarter dividend of $0.06 per share to be paid in December 2023, for shareholders of record on November 30, 2023.

Based on current market conditions and the Company's low financial leverage, Enerplus expects to continue to return significant free cash flow to shareholders in 2024. Enerplus anticipates its return of capital will equal approximately 70% of free cash flow in 2024.

UPDATED GHG EMISSIONS TARGETS

Enerplus has made significant progress in reducing its GHG emissions intensity through improved operational processes and planning, and investment in emissions reduction projects. The Company now expects to exceed its 2030 scope 1 and 2 emissions intensity reduction target this year, representing an approximate reduction of 40% from the 2021 baseline (and 55% from 2019). Enerplus is also tracking ahead of its existing methane intensity reduction targets in 2023, where it expects to achieve an approximate 45% reduction from the 2021 baseline (and 65% from 2019).

As a result of the outperformance noted above, Enerplus is revising its GHG and methane emissions intensity targets as follows:

- Scope 1 GHG emissions intensity of 7 kg CO_2e/BOE by 2030; an approximate 60% reduction from 2023
- Scope 1 & 2 GHG emissions intensity of 13 kg CO_2e/MBOE by 2030; an approximate 30% reduction from 2023
- Methane emissions intensity of 0.02 kg CH_4/MBOE by 2030; an approximate 45% reduction from 2023

In addition, Enerplus is endorsing the World Bank Zero Routine Flaring by 2030 initiative and has established a flare intensity target of less than 2% per thousand cubic feet of natural gas produced by 2026.

2023 GUIDANCE UPDATE

Capital spending guidance in 2023 has been narrowed to $520 to $540 million from the prior range of $510 to $550 million.

Annual production guidance has been revised to 98,000 to 99,000 BOE per day from the prior range of 94,500 to 98,500 BOE per day, representing an increase of 2,000 BOE per day at the midpoint. Annual liquids production guidance has been revised to 60,500 to 61,500 barrels per day from the prior range of 58,500 to 61,500 barrels per day, representing an increase of 1,000 barrels per day at the midpoint.

Enerplus is providing fourth quarter 2023 production guidance of 95,000 to 99,000 BOE per day, including liquids production of 60,500 to 64,500 barrels per day.

A summary of the changes to Enerplus' 2023 guidance is provided in the tables below.

2023 Guidance Summary

	Updated Guidance	Previous Guidance
Capital spending	$520 – 540 million	$510 – 550 million
Average total production	98,000 – 99,000 BOE/day	94,500 – 98,500 BOE/day
Average liquids production	60,500 – 61,500 bbls/day	58,500 – 61,500 bbls/day
Fourth quarter total production	95,000 – 99,000 BOE/day	N/A
Fourth quarter liquids production	60,500 – 64,500 bbls/day	N/A
Average production tax rate (% of net sales, before transportation)	8% (No change)	8%
Operating expense	$10.75 – $11.00/BOE	$10.75 – $11.50/BOE
Transportation expense	$4.05/BOE	$4.20/BOE
Cash G&A expense	$1.35/BOE (No change)	$1.35/BOE
Current tax expense	3 – 4% of adjusted funds flow, before tax (No change)	3 – 4% of adjusted funds flow, before tax

2023 Differential/Basis Outlook(1)

	Updated Guidance	Previous Guidance
U.S. Bakken crude oil differential (compared to WTI crude oil)	$(0.25)/bbl	Par with WTI
Marcellus natural gas sales price differential (compared to last day NYMEX natural gas)	$(0.75)/Mcf (No change)	$(0.75)/Mcf

(1) Excluding transportation costs.

Q3 2023 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 3, 2023, to discuss these results. Details of the conference call are as follows:

Date: Friday, November 3, 2023
Time: 9:00 AM MT (11:00 AM ET)
Dial-In: 1-888-390-0546 (Toll Free)
Conference ID: 18470310
Audiocast: https://app.webinar.net/Vl8X1bX2M37

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: 470310 #

PRICE RISK MANAGEMENT

The following is a summary of Enerplus' financial commodity hedging contracts at September 30, 2023 and positions entered into subsequent to September 30, 2023 and up to November 1, 2023.

	WTI Crude Oil ($/bbl)(1)(2)		NYMEX Natural Gas ($/Mcf)(2)
	Oct 1, 2023 – Dec 31, 2023	Jan 1, 2024 – Jun 30, 2024	Oct 1, 2023 – Oct 31, 2023
Swaps			
Volume (bbls/day)	10,000	–	–
Brent - WTI Spread	$ 5.47	–	–
3 Way Collars			
Volume (bbls/day)	10,000	5,000	–
Sold Puts	$ 65.00	$ 65.00	–
Purchased Puts	$ 81.00	$ 77.00	–
Sold Calls	$ 111.58	$ 95.00	–
Collars			
Volume (Mcf/day)	–	–	50,000
Volume (bbls/day)(3)	2,000	–	–
Purchased Puts	$ 5.00	–	$ 4.05
Sold Calls	$ 75.00	–	$ 7.00

(1) The total average deferred premium spent on our outstanding crude oil contracts is $1.19/bbl from October 1, 2023 – June 30, 2024.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Outstanding commodity derivative instruments acquired as part of the Company's acquisition of Bruin E&P Holdco, LLC completed in 2021.

THIRD QUARTER 2023 PRODUCTION AND OPERATIONAL SUMMARY TABLES

Summary of Average Daily Production[1]

	Three months ended September 30, 2023				Nine months ended September 30, 2023			
	Williston Basin	Marcellus	Other[2]	Total	Williston Basin	Marcellus	Other[2]	Total
Tight oil (bbl/d)	53,002	—	1,193	54,195	48,815	—	875	49,690
Total crude oil (bbl/d)	**53,002**	**—**	**1,193**	**54,195**	**48,815**	**—**	**875**	**49,690**
Natural gas liquids (bbl/d)	**12,347**	**—**	**83**	**12,430**	**10,774**	**—**	**97**	**10,871**
Shale gas (Mcf/d)	74,120	144,523	758	219,401	69,299	159,509	783	229,591
Total natural gas (Mcf/d)	**74,120**	**144,523**	**758**	**219,401**	**69,299**	**159,509**	**783**	**229,591**
Total production (BOE/d)	**77,702**	**24,087**	**1,403**	**103,192**	**71,139**	**26,585**	**1,102**	**98,826**

(1) Table may not add due to rounding.
(2) Largely comprises the DJ Basin.

Summary of Wells Drilled[1]

	Three months ended September 30, 2023				Nine months ended September 30, 2023			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	15	12.0	11	0.5	46	39.6	66	7.0
Marcellus	—	—	14	0.4	—	—	40	0.8
DJ Basin	—	—	—	—	3	2.9	—	—
Total	**15**	**12.0**	**25**	**0.9**	**49**	**42.5**	**106**	**7.7**

(1) Table may not add due to rounding.

Summary of Wells Brought On-Stream[1]

	Three months ended September 30, 2023				Nine months ended September 30, 2023			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	19	17.2	26	3.3	46	40.0	40	6.5
Marcellus	—	—	1	0.0	—	—	22	0.3
DJ Basin	3	2.9	—	—	3	2.9	10	0.2
Total	**22**	**20.2**	**27**	**3.3**	**49**	**43.0**	**72**	**7.0**

(1) Table may not add due to rounding.

Readers are encouraged to review the 2023 interim Management's Discussion & Analysis (MD&A) and financial statements, and 2022 MD&A and financial statements filed on SEDAR+ and as part of our Form 6-K and Form 40-F, respectively, on EDGAR concurrently with this news release for more complete disclosure on our operations.

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.

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

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: 2023 production and capital spending guidance; fourth quarter 2023 production guidance; Enerplus' return of capital plans, including expectations regarding payment of dividends and the source of funds related thereto; the funding of dividends and the share repurchase program from free cash flow; the anticipated percentage of free cash flow planned to be returned to shareholders, based on current commodity prices; expectations regarding Enerplus' share purchase program, including the timing and amounts thereof; expectations regarding the number of net operated wells brought on production during the remainder of 2023; expected operating strategy in 2023 and expectations regarding our drilling program; expectations regarding oil production growth and free cash flow profile for the remainder of 2023; anticipated reduction levels of Enerplus' scope 1 and 2 GHG emissions intensities targets and its flare intensity target and the timing thereof; methane emissions targets and expectations; oil and natural gas prices and differentials and expectations regarding the market environment and our commodity risk management program in 2023; 2023 Bakken and Marcellus differential guidance; capital spending guidance; expectations regarding realized oil and natural gas prices; and expected operating, transportation and cash G&A expenses and production taxes and 2023 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 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; that we will conduct our operations and achieve results of operations as anticipated; 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 and storage fundamentals; 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; our ability to comply with our debt covenants; our ability to meet the targets associated with our credit facilities; 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 2023 guidance described in this news release is based on rest of year commodity prices of: a WTI price of $80.00/bbl, a NYMEX price of $3.00/Mcf 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 greater 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: continued instability, or further deterioration, in global economic and market environment, including from 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 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 our third quarter 2023 MD&A, our annual information form for the year ended December 31, 2022, our 2022 annual MD&A and Form 40-F as at December 31, 2022).

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

Readers are referred to "Non-GAAP Measures" in Enerplus' third quarter 2023 MD&A for supplementary financial measures, which information is incorporated by reference to this new release.

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: (a) indicated the composition of the measure; (b) identified the most directly comparable GAAP financial measure and provided comparative detail where appropriate; (c) indicated the reconciliation of the measure to the most directly comparable GAAP financial measure to the extent one exists; and (d) 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).

	Three months ended September 30,	
($ millions)	**2023**	**2022**
Net income/(loss)	**$ 127.7**	**$ 305.9**
Unrealized derivative instrument, foreign exchange and marketable securities (gain)/loss	15.6	(128.5)
Other expense/(income) related to investing activities	(1.4)	—
Tax effect	(4.7)	30.5
Adjusted net income/(loss)	**$ 137.2**	**$ 207.9**
Adjusted net income/(loss) per share (basic)	**$ 0.65**	**$ 0.90**

"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)	**2023**	**2022**
Cash flow from/(used in) operating activities	$ 212.2	$ 409.9
Asset retirement obligation settlements	2.5	1.6
Changes in non-cash operating working capital	49.0	(55.9)
Adjusted funds flow	**$ 263.7**	**$ 355.6**
Capital spending	(121.4)	(114.5)
Free cash flow	**$ 142.3**	**$ 241.1**

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 5 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.

Electronic copies of Enerplus' 2023 interim and 2022 annual 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 2, 2023 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, 2023 and 2022 (the "Interim Financial Statements") and notes thereto;

- the audited consolidated financial statements of Enerplus at December 31, 2022 and 2021 and for the years ended December 31, 2022, 2021 and 2020; and

- the MD&A for the year ended December 31, 2022 (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, 2022 (the "Annual Information Form").

BASIS OF PRESENTATION

The Interim Financial Statements and notes thereto have been prepared in accordance with U.S. GAAP. Unless otherwise stated, all dollar amounts are presented in U.S. dollars. Certain prior period amounts have been restated to conform with current period presentation as a result of the voluntary and retroactively applied change in the presentation currency from Canadian to U.S. dollars adopted by the Company in the fourth quarter of 2021.

The functional currency of the parent company changed from Canadian dollars to U.S. dollars effective January 1, 2023. This was the result of a gradual change in the primary economic environment in which the entity operates, culminating in the sale of Enerplus' remaining Canadian operating assets at the end of 2022. This has triggered a prospective change as of January 1, 2023 in functional currency of the parent entity to U.S. dollars, consistent with the functional currency of its U.S. subsidiaries. All assets and liabilities held by the parent company were translated at the exchange rate at December 31, 2022 to determine opening balances in U.S. dollars. Amounts that are part of Shareholders' Equity of the parent company were translated at historical exchange rates. Monetary assets and liabilities denominated in Canadian dollars will be revalued at current exchange rates at each reporting period. Upon settlement and/or realization of Canadian dollar denominated assets and liabilities, there may be realized foreign exchange gains and losses depending on the change in the foreign exchange rate when the transaction was originally recorded and the final settlement date.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE 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 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1 or 0.167:1, as applicable, utilizing a conversion on this basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading.

In accordance with U.S. GAAP, crude oil and natural gas sales are presented net of royalties in the Financial Statements. In addition, unless otherwise noted, all production volumes are 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.

All references to "liquids" in this MD&A include light and medium 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

Crude oil and natural gas liquids production increased by 14% to 66,625 BOE/day during the third quarter of 2023, compared to the second quarter of 2023, primarily due to strong well performance from additional wells coming on-stream in North Dakota. Total production during the third quarter of 2023 averaged 103,192 BOE/day, an increase of 8% compared to average production of 95,572 BOE/day in the second quarter of 2023. As a result, we are increasing our average annual production guidance for 2023 to 98,000 BOE/day - 99,000 BOE/day, including 60,500 bbls/day - 61,500 bbls/day of crude oil and natural gas liquids, from 94,500 BOE/day - 98,500 BOE/day, including 58,500 bbls/day - 61,500 bbls/day of crude oil and natural gas liquids. For the fourth quarter of 2023, we expect average production of 95,000 BOE/day - 99,000 BOE/day, including 60,500 bbls/day - 64,500 bbls/day of crude oil and natural gas liquids.

During the third quarter of 2023, a total of $67.7 million was returned to shareholders through share repurchases and dividends, an increase from $66.5 million in the second quarter of 2023. As previously announced, we plan to return at least 60% of second half 2023 free cash flow1 to our shareholders, which is expected to result in over 70% of full year 2023 free cash flow returned. In conjunction with this plan, the Board of Directors approved a fourth quarter dividend of $0.06 per share to be paid in December 2023. The Company expects to continue to return significant free cash flow to shareholders in 2024 and anticipates its return of capital will equal approximately 70% of free cash flow. The Company expects to continue to prioritize share repurchases for the majority of its return of capital plan, based on current market conditions. We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

Capital spending during the third quarter of 2023 was $121.4 million, compared to $180.9 million during the second quarter of 2023, with the majority of the spending focused on our U.S. crude oil properties. The decrease in capital spending was due to less completions activity during the third quarter of 2023. We are narrowing our annual capital spending guidance for 2023 to range between $520 - $540 million from $510 - $550 million.

Our realized Bakken crude oil price differential averaged $0.20/bbl above WTI during the third quarter of 2023, compared to $0.71/bbl below WTI during the second quarter of 2023. The stronger realized differential was due to higher prices for crude oil delivered to downstream markets in both Patoka and the U.S. Gulf Coast via the Dakota Access Pipeline combined with a recovery in WTI prices throughout the summer. Additionally, U.S. refinery utilizations and margins remained strong throughout the third quarter of 2023. Bakken crude oil prices have weakened in the fourth quarter of 2023 due to increased basin production and lower seasonal refinery demand resulting from planned maintenance outages. As a result, we are revising our 2023 expected annual realized Bakken crude oil price differential to $0.25/bbl below WTI, from a crude oil price differential at par to WTI, previously.

Our realized Marcellus sales price differential averaged $1.24/Mcf below NYMEX in the third quarter of 2023 compared to $0.68/Mcf below NYMEX in the second quarter of 2023. The wider differential was mainly due to increased supply in the northeast U.S. and regional storage levels tracking above historical averages. As a result of weaker expected realized differentials, we are revising our 2023 expected annual realized Marcellus natural gas differential to average $0.85/Mcf below NYMEX, from a natural gas differential of $0.75/Mcf below NYMEX, previously.

Operating expenses for the third quarter of 2023 increased to $96.6 million, or $10.17/BOE, compared to $89.1 million, or $10.25/BOE during the second quarter of 2023. The increase in total spend was due to higher production as a result of new wells brought on stream during the second and third quarters of 2023. We continue to expect operating expenses in the fourth quarter of 2023 to increase compared to the third quarter of 2023, due to planned workover activity. As a result, we are revising our operating expenses guidance for 2023 to range between $10.75/BOE - $11.00/BOE from $10.75/BOE - $11.50/BOE.

We reported net income of $127.7 million in the third quarter of 2023, compared to net income of $74.2 million in the second quarter of 2023. Net income increased primarily due to higher commodity prices and crude oil and natural gas liquids production in the third quarter of 2023.

In the third quarter of 2023, cash flow from operating activities and adjusted funds flow increased to $212.2 million and $263.7 million, respectively, compared to $186.6 million and $196.6 million in the second quarter of 2023. The increase was primarily due to higher commodity prices and crude oil and natural gas liquids production in the third quarter of 2023.

At September 30, 2023, net debt increased to $212.1 million, compared to $199.6 million at June 30, 2023. Net debt is calculated as total debt, which was comprised of our senior notes and borrowing on our $900 million sustainability linked lending (“SLL”) bank credit facility and our $365 million SLL bank credit facility (together referred to as the “Bank Credit Facilities”), less cash on hand of $46.2 million. Net debt increased primarily due to working capital changes, as our non-cash operating and investing working capital deficit changed by approximately $85.0 million in the third quarter of 2023. At September 30, 2023, a total of $135.7 million was drawn on our Bank Credit Facilities. Our net debt to adjusted funds flow ratio was 0.2x, which remains consistent with the second quarter of 2023.

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

RESULTS OF OPERATIONS

Production

Crude oil and natural gas liquids production increased by 14% during the third quarter of 2023, compared to the second quarter of 2023, primarily due to 17.2 net operated and 3.3 net non-operated wells coming on-stream in North Dakota. The increase in crude oil and natural gas production was partially offset by a 6% decrease in natural gas production in the Marcellus as a result of limited capital investment during 2023. As a result, total production during the third quarter of 2023 averaged 103,192 BOE/day, an increase of 8% compared to average production of 95,572 BOE/day in the second quarter of 2023.

Production decreased for the three months ended September 30, 2023 compared to the same period in 2022, due to the sale of substantially all of our Canadian assets in the fourth quarter of 2022, and a decrease in natural gas production in the Marcellus as a result of limited capital investment during 2023. Production for the nine months ended September 30, 2023, increased compared to the same period in 2022 due to strong well performance from new wells brought online, and an increase in gas capture which contributed to higher natural gas liquids and natural gas production volumes in North Dakota, partially offset by the sale of our Canadian assets in the fourth quarter of 2022.

Our crude oil and natural gas liquids weighting increased to 65% from 63% for the three months ended September 30, 2023 and decreased to 61% from 62% for the nine months ended September 30, 2023, compared to the same periods in 2022.

We are increasing our average annual total production guidance for 2023 to 98,000 BOE/day - 99,000 BOE/day, including 60,500 bbls/day - 61,500 bbls/day of crude oil and natural gas liquids, from 94,500 BOE/day - 98,500 BOE/day, including 58,500 bbls/day - 61,500 bbls/day of crude oil and natural gas liquids. For the fourth quarter of 2023, we expect average production of 95,000 BOE/day - 99,000 BOE/day, including 60,500 bbls/day - 64,500 bbls/day of crude oil and natural gas liquids.

Average daily production volumes for the three and nine months ended September 30, 2023 and 2022 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2023**	**2022**	**% Change**	**2023**	**2022**	**% Change**
Tight oil (bbls/day)	54,195	52,793	3%	49,690	46,194	8%
Light and medium oil (bbls/day)	—	2,038	(100%)	—	2,097	(100%)
Heavy oil (bbls/day)	—	2,651	(100%)	—	2,855	(100%)
Total crude oil (bbls/day)	54,195	57,482	(6%)	49,690	51,146	(3%)
Natural gas liquids (bbls/day)	12,430	10,900	14%	10,871	9,319	17%
Shale gas - Marcellus (Mcf/day)	144,523	164,731	(12%)	159,509	164,843	(3%)
Shale gas - Bakken (Mcf/day)	74,878	64,918	15%	70,082	53,863	30%
Conventional natural gas (Mcf/day)	—	6,909	(100%)	—	7,139	(100%)
Total natural gas (Mcf/day)	219,401	236,558	(7%)	229,591	225,845	2%
Total daily sales (BOE/day)	103,192	107,808	(4%)	98,826	98,106	1%

Pricing

The prices received for crude oil, natural gas liquids 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)	**2023**	**2022**	**Q3 2023**	**Q2 2023**	**Q1 2023**	**Q4 2022**	**Q3 2022**
Benchmarks							
WTI crude oil ($/bbl)	$ 77.39	$ 98.09	$ 82.26	$ 73.78	$ 76.13	$ 82.65	$ 91.56
Brent (ICE) crude oil ($/bbl)	82.06	102.33	85.95	78.01	82.22	88.60	97.81
Propane – Conway ($/bbl)	29.56	49.98	27.98	27.70	32.99	34.21	44.73
NYMEX natural gas – last day ($/Mcf)	2.69	6.77	2.55	2.10	3.42	6.26	8.20
CDN/US average exchange rate	0.74	0.78	0.74	0.74	0.74	0.74	0.77
CDN/US period end exchange rate	0.74	0.72	0.74	0.76	0.74	0.74	0.72
Enerplus selling price[1]							
Crude oil ($/bbl)	$ 77.50	$ 97.44	$ 82.66	$ 72.69	$ 76.34	$ 83.06	$ 92.48
Natural gas liquids ($/bbl)	18.36	34.13	19.21	15.49	20.55	21.88	32.04
Natural gas ($/Mcf)	1.91	5.79	1.37	1.08	3.18	4.76	6.53
Average differentials							
Bakken DAPL – WTI ($/bbl)	$ 0.94	$ 2.43	$ 0.73	$ 0.78	$ 1.32	$ 3.19	$ 3.60
Brent (ICE) – WTI ($/bbl)	4.67	4.24	3.69	4.23	6.09	5.95	6.25
Transco Leidy monthly – NYMEX ($/Mcf)	(0.88)	(0.89)	(1.47)	(0.63)	(0.54)	(1.51)	(1.06)
Transco Z6 Non-New York monthly – NYMEX ($/Mcf)	0.47	(0.10)	(1.36)	(0.57)	3.35	(0.20)	(0.85)
Enerplus realized differentials[1][2]							
Bakken crude oil – WTI ($/bbl)	$ (0.16)	$ 1.07	$ 0.20	$ (0.71)	$ 0.06	$ 1.05	$ 2.41
Marcellus natural gas – NYMEX ($/Mcf)	(0.83)	(0.53)	(1.24)	(0.68)	(0.64)	(1.18)	(0.99)

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

CRUDE OIL

During the third quarter of 2023, our realized crude oil sales price averaged $82.66/bbl, an increase of 14% compared to the second quarter of 2023, in line with the increases in the underlying benchmark WTI price and Bakken differentials over the same period. WTI prices increased through the third quarter of 2023 due to strong demand for refined products during the peak summer consumption period as well as additional voluntary production cuts by Saudi Arabia and Russia through the end of the year.

Our realized Bakken crude oil price differential averaged $0.20/bbl above WTI during the third quarter of 2023, compared to $0.71/bbl below WTI during the second quarter of 2023. The stronger realized differential was due to higher prices for crude oil delivered to downstream markets in both Patoka and the U.S. Gulf Coast via the Dakota Access Pipeline combined with a recovery in WTI prices throughout the summer. Additionally, U.S. refinery utilizations and margins remained strong throughout the third quarter of 2023. Bakken crude oil prices have weakened in the fourth quarter of 2023 due to increased basin production and lower seasonal refinery demand resulting from planned maintenance outages. As a result, we are revising our 2023 expected annual realized Bakken crude oil price differential to $0.25/bbl below WTI, from a crude oil price differential at par to WTI, previously.

NATURAL GAS LIQUIDS

Our realized sales price for natural gas liquids averaged $19.21/bbl during the third quarter of 2023 compared to $15.49/bbl during the second quarter of 2023. The improved realized differentials were primarily due to an adjustment in our overall natural gas liquids composition due to wells coming on stream in the Little Knife area. Propane price weakness continued during the third quarter of 2023 due to high inventories, growing production, and reliance on exports to balance the North American market. Benchmark propane pricing at Conway remained flat, even as prices rose for other energy products.

NATURAL GAS

Our realized natural gas sales price averaged $1.37/Mcf during the third quarter of 2023, an increase of 27% compared to the second quarter of 2023. The NYMEX benchmark price increased by 21% over the same period. The difference in price realization versus the benchmark was due to stronger regional prices received for our Bakken natural gas production, which offset weakness in Marcellus regional prices.

Our realized Marcellus sales price differential averaged $1.24/Mcf below NYMEX in the third quarter of 2023 compared to $0.68/Mcf below NYMEX in the second quarter of 2023. The wider differential was mainly due to increased supply in the northeast U.S. and regional storage levels tracking above historical averages. As a result of weaker expected realized differentials, we are revising our 2023 expected annual realized Marcellus natural gas differential to average $0.85/Mcf below NYMEX, from a natural gas differential of $0.75/Mcf below NYMEX, previously.

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. At November 1, 2023, we have hedged 10,000 bbls/day of WTI crude oil price exposure for the remainder of 2023. Additionally, we have hedged 5,000 bbls/day of WTI crude oil price exposure for the period January 1, 2024 to June 30, 2024. Our crude oil contracts include 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 table summarizes Enerplus' price risk management positions at September 30, 2023, and positions entered into subsequent to September 30, 2023 and up to November 1, 2023:

	WTI Crude Oil ($/bbl)[1][2]		NYMEX Natural Gas ($/Mcf)[2]
	Oct 1, 2023 – Dec 31, 2023	Jan 1, 2024 – Jun 30, 2024	Oct 1, 2023 – Oct 31, 2023
Swaps			
Volume (bbls/day)	10,000	–	–
Brent - WTI Spread	$ 5.47	–	–
3 Way Collars			
Volume (bbls/day)	10,000	5,000	–
Sold Puts	$ 65.00	$ 65.00	–
Purchased Puts	$ 81.00	$ 77.00	–
Sold Calls	$ 111.58	$ 95.00	–
Collars			
Volume (Mcf/day)	–	–	50,000
Volume (bbls/day)[3]	2,000	–	–
Purchased Puts	$ 5.00	–	$ 4.05
Sold Calls	$ 75.00	–	$ 7.00

(1) The total average deferred premium spent on our outstanding crude oil contracts is $1.19/bbl from October 1, 2023 – June 30, 2024.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Outstanding commodity derivative instruments acquired as part of the Company's acquisition of Bruin E&P Holdco, LLC completed in 2021.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	**Three months ended September 30,**		**Nine months ended September 30,**	
($ millions)	**2023**	**2022**	**2023**	**2022**
Realized gains/(losses):				
Crude oil	$ (1.6)	$ (50.5)	$ 7.1	$ (233.1)
Natural gas	6.9	(38.0)	46.7	(66.7)
Total realized gains/(losses)	$ 5.3	$ (88.5)	$ 53.8	$ (299.8)
Unrealized gains/(losses):				
Crude oil	$ (14.0)	$ 126.0	$ (8.8)	$ 98.8
Natural gas	(5.9)	19.5	(24.7)	3.6
Total unrealized gains/(losses)	$ (19.9)	$ 145.5	$ (33.5)	$ 102.4
Total commodity derivative instruments gains/(losses)	$ (14.6)	$ 57.0	$ 20.3	$ (197.4)

	Three months ended September 30,		**Nine months ended September 30,**	
(Per BOE)	**2023**	**2022**	**2023**	**2022**
Total realized gains/(losses)	$ 0.56	$ (8.92)	$ 1.99	$ (11.19)
Total unrealized gains/(losses)	(2.10)	14.67	(1.24)	3.82
Total commodity derivative instruments gains/(losses)	$ (1.54)	$ 5.75	$ 0.75	$ (7.37)

During the three and nine months ended September 30, 2023, Enerplus realized a loss of $1.6 million and a gain of $7.1 million, respectively, on our crude oil contracts, compared to realized losses of $50.5 million and $233.1 million for the same periods in 2022. For the three and nine months ended September 30, 2023, realized gains of $6.9 million and $46.7 million, respectively, were recorded on our natural gas contracts, compared to realized losses of $38.0 million and $66.7 million for the same periods in 2022. Realized gains recorded during the three and nine months ended September 30, 2023 were due to natural gas commodity prices falling below the purchased put 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, 2023, the fair value of our crude oil and natural gas contracts was in a net liability position of $5.3 million (December 31, 2022 – net asset position of $26.1 million). For the three and nine months ended September 30, 2023, the change in the fair value of our crude oil contracts resulted in unrealized losses of $14.0 million and $8.8 million, respectively, compared to unrealized gains of $126.0 million and $98.8 million, during the same periods in 2022. For the three and nine months ended September 30, 2023, we recorded unrealized losses on our natural gas contracts of $5.9 million and $24.7 million, respectively, compared to unrealized gains of $19.5 million and $3.6 million, during the same periods in 2022.

Crude Oil and Natural Gas Sales

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2023	2022	2023	2022
Crude oil and natural gas sales	$ 461.8	$ 663.5	$ 1,226.0	$ 1,804.7
Per BOE	$ 48.65	$ 66.90	$ 45.44	$ 67.38

Crude oil and natural gas sales for the three and nine months ended September 30, 2023 were $461.8 million, or $48.65/BOE, and $1,226.0 million, or $45.44/BOE, respectively, compared to $663.5 million, or $66.90/BOE, and $1,804.7 million, or $67.38/BOE, for the same periods in 2022. The decrease in crude oil and natural gas sales was primarily due to lower commodity prices and Marcellus production during the three and nine months ended September 30, 2023, and the impact of the Canadian divestments completed in the fourth quarter of 2022.

Operating Expenses

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2023	2022	2023	2022
Operating expenses	$ 96.6	$ 103.8	$ 278.5	$ 270.5
Per BOE	$ 10.17	$ 10.47	$ 10.32	$ 10.10

For the three and nine months ended September 30, 2023, operating expenses were $96.6 million, or $10.17/BOE, and $278.5 million, or $10.32/BOE, respectively, compared to $103.8 million, or $10.47/BOE, and $270.5 million, or $10.10/BOE, for the same periods in 2022. During the three months ended September 30, 2023, the decrease was due to the impact of the Canadian divestments completed in the fourth quarter of 2022, partially offset by higher gas facility charges and lower natural gas production in the Marcellus which has lower associated operating expenses. During the nine months ended September 30, 2023, the increase was due to inflation adjusted contract pricing and lower natural gas production in the Marcellus, offset by the Canadian divestments completed in the fourth quarter of 2022.

We continue to expect operating expenses in the fourth quarter of 2023 to increase compared to the third quarter of 2023, due to planned workover activity. We are revising our operating expenses guidance for 2023 to range between $10.75/BOE - $11.00/BOE from $10.75/BOE - $11.50/BOE.

Transportation Costs

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2023	2022	2023	2022
Transportation costs	$ 36.7	$ 41.3	$ 108.9	$ 114.9
Per BOE	$ 3.87	$ 4.16	$ 4.04	$ 4.29

For the three and nine months ended September 30, 2023, transportation costs were $36.7 million, or $3.87/BOE, and $108.9 million, or $4.04/BOE, respectively, compared to $41.3 million, or $4.16/BOE, and $114.9 million, or $4.29/BOE for the same periods in 2022. The decrease was due to a higher proportion of total production volumes from areas with lower associated transportation costs, offset by the impact of the Canadian divestments in the fourth quarter of 2022.

We are revising our transportation costs guidance for 2023 to $4.05/BOE from $4.20/BOE.

Production Taxes

($ millions, except per BOE amounts)	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Production taxes	$ 40.0	$ 48.2	$ 98.8	$ 127.4
Per BOE	$ 4.21	$ 4.86	$ 3.65	$ 4.76
Production taxes (% of crude oil and natural gas sales)	8.7%	7.3%	8.1%	7.1%

Production taxes for the three and nine months ended September 30, 2023, were $40.0 million, or 8.7%, and $98.8 million, or 8.1%, respectively, compared to $48.2 million, or 7.3%, and $127.4 million, or 7.1% for the same periods in 2022. The decrease in total production taxes for the three and nine months ended September 30, 2023, was primarily due to lower realized prices and higher effective tax rates on U.S. crude oil during June to October 2022 as WTI based pricing exceeded certain thresholds. The increase in production tax as a percentage of revenue for the three and nine months ended September 30, 2023 was due to increased U.S. crude oil production which has higher rates of production tax combined with decreased natural gas and natural gas liquids revenues with lower associated production taxes, compared to the same periods in 2022.

We continue to expect production taxes to average 8% in 2023.

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, 2023 Crude Oil	Natural Gas	Total
Average Daily Production	79,100 BOE/day	144,549 Mcfe/day	103,192 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 61.07	$ 1.31	$ 48.65
Operating expenses	(12.93)	(0.19)	(10.17)
Transportation costs	(3.37)	(0.92)	(3.87)
Production taxes	(5.40)	(0.05)	(4.21)
Netback before impact of commodity derivative contracts	$ 39.37	$ 0.15	$ 30.40
Realized gains/(losses) on commodity derivative contracts	(0.22)	0.52	0.56
Netback after impact of commodity derivative contracts	$ 39.15	$ 0.67	$ 30.96
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 286.5	$ 2.0	$ 288.5
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 284.9	$ 8.9	$ 293.8

(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, 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 gains/(losses) on commodity derivative contracts	(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)	$ 325.5	$ 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	Nine months ended September 30, 2023 Crude Oil	Natural Gas	Total
Average Daily Production	72,209 BOE/day	159,702 Mcfe/day	98,826 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 57.98	$ 1.91	$ 45.44
Operating expenses	(13.72)	(0.19)	(10.32)
Transportation costs	(3.54)	(0.90)	(4.04)
Production taxes	(4.94)	(0.03)	(3.65)
Netback before impact of commodity derivative contracts	$ 35.78	$ 0.79	$ 27.43
Realized gains/(losses) on commodity derivative contracts	0.36	1.07	1.99
Netback after impact of commodity derivative contracts	$ 36.14	$ 1.86	$ 29.42
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 705.4	$ 34.4	$ 739.8
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 712.4	$ 81.2	$ 793.6

(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 gains/(losses) on commodity derivative contracts	(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.

Total netbacks before and after the impact of commodity derivative contracts for the three and nine months ended September 30, 2023 were lower compared to the same periods in 2022, due to lower realized commodity prices.

For the three and nine months ended September 30, 2023, crude oil properties accounted for 99% and 95%, respectively, of total netback before commodity derivative contracts, compared to 80% and 82% during the same periods in 2022, as a result of lower realized natural gas prices in 2023.

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”).

($ millions)	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Cash:				
G&A expenses	$ 12.1	$ 10.9	$ 35.4	$ 31.5
Share-based compensation expense/(recovery)	1.9	1.2	1.1	3.6
Non-Cash:				
Share-based compensation expense/(recovery)	5.0	3.8	17.2	14.3
Equity swap gain	—	—	—	(1.0)
G&A recovery	(0.1)	(0.1)	(0.3)	(0.3)
Total G&A expenses	$ 18.9	$ 15.8	$ 53.4	$ 48.1

(Per BOE)	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Cash:				
G&A expenses	$ 1.27	$ 1.10	$ 1.31	$ 1.18
Share-based compensation expense/(recovery)	0.20	0.12	0.04	0.13
Non-Cash:				
Share-based compensation expense/(recovery)	0.53	0.38	0.64	0.53
Equity swap gain	—	—	—	(0.04)
G&A recovery	(0.01)	(0.01)	(0.01)	(0.01)
Total G&A expenses	$ 1.99	$ 1.59	$ 1.98	$ 1.79

Cash G&A expenses for the three and nine months ended September 30, 2023 were $12.1 million, or $1.27/BOE, and $35.4 million, or $1.31/BOE, respectively, compared to $10.9 million, or $1.10/BOE, and $31.5 million, or $1.18/BOE, for the same periods in 2022. Total cash G&A expenses increased primarily 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. Cash-settled SBC for the three and nine months ended September 30, 2023, was an expense of $1.9 million, or $0.20/BOE, and an expense of $1.1 million, or $0.04/BOE, respectively, compared to expenses of $1.2 million, or $0.12/BOE, and $3.6 million, or $0.13/BOE, for the same periods in 2022, and relates to our director plans. The large expense in 2022 was due to a significant increase in Enerplus' share price from 2021.

Equity-settled non-cash SBC for the three and nine months ended September 30, 2023, was $5.0 million, or $0.53/BOE, and $17.2 million, or $0.64/BOE, respectively, compared to $3.8 million, or $0.38/BOE, and $14.3 million, or $0.53/BOE, for the same periods in 2022. Performance Share Units ("PSUs"), as one of the equity-settled LTI plans, are impacted by performance multipliers. For the three months ended September 30, 2023, the increase was due to the applicable multipliers being higher compared to the same period in 2022. For the nine months ended September 30, 2023, the increase was due to additional expense for retirement eligible individuals, compared to the same period in 2022.

Enerplus previously had hedged a portion of the outstanding cash-settled units under its LTI plans. During the nine months ended September 30, 2022, we recorded a mark-to-market gain of $1.0 million as a result of higher share prices. Enerplus settled its equity derivative contracts during 2022 and did not have any equity derivatives outstanding at September 30, 2023.

We continue to expect cash G&A expenses of $1.35/BOE in 2023.

Interest Expense

For the three and nine months ended September 30, 2023, we recorded a total interest expense of $4.8 million and $12.7 million, respectively, compared to $6.5 million and $18.6 million for the same periods in 2022. The decrease was primarily due to lower debt levels during the three and nine months ended September 30, 2023, compared to the same period in 2022, as lower debt levels were sustained throughout 2023.

At September 30, 2023, $135.7 million was drawn on the Bank Credit Facilities. At September 30, 2023, approximately 47% of our debt was based on fixed interest rates and 53% on floating interest rates (December 31, 2022 – 78%, 22%), with a weighted average interest rate of 4.1% and 6.6%, respectively (December 31, 2022 – 4.1%, 5.7%).

Foreign Exchange

($ millions)	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Realized:				
Foreign exchange (gain)/loss	$ (0.1)	$ 0.1	$ (0.2)	$ —
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company	—	(1.0)	—	(1.1)
Unrealized:				
Foreign exchange (gain)/loss on Canadian dollar working capital in parent company	0.7	—	(0.1)	—
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company	—	17.0	—	14.9
Total foreign exchange (gain)/loss	$ 0.6	$ 16.1	$ (0.3)	$ 13.8
CDN/US average exchange rate	0.74	0.77	0.74	0.78
CDN/US period end exchange rate	0.74	0.72	0.74	0.72

For the three and nine months ended September 30, 2023, Enerplus recorded a foreign exchange loss of $0.6 million and a gain of $0.3 million, respectively, compared to gains of $16.1 million and $13.8 million for the same periods in 2022. The decrease for the three and nine months ended September 30, 2023, was due to Enerplus previously recording unrealized foreign exchange gains and losses on the translation of our U.S. dollar denominated working capital held in Canada at each period-end, prior to the functional currency change of the parent company to U.S. dollars on January 1, 2023.

Enerplus is exposed to foreign exchange risk as it relates to certain activities transacted in Canadian dollars. The parent company and its subsidiaries have a U.S. dollar functional currency, and the parent company has both U.S. and Canadian dollar transactions. Canadian denominated monetary assets and liabilities are subject to revaluation from the source currency of Canadian dollars to the functional currency of U.S. dollars, generating realized and unrealized foreign exchange (gains)/losses in the Condensed Consolidated Statements of Income/(Loss). For the three and nine months ended September 30, 2022, Enerplus recorded unrealized foreign exchange losses of $17.0 million and $14.9 million, respectively, due to the impact of the weaker Canadian dollar on the U.S. dollar-denominated working capital held in the parent company, which had a Canadian dollar functional currency until December 31, 2022.

Following the change in functional currency of the parent company to U.S. dollars on January 1, 2023, the net investment hedge on the U.S. dollar denominated debt held in the parent entity for the U.S. subsidiaries was no longer required. Previously, the unrealized foreign exchange gains and losses arising from the translation of the debt were recorded in Other Comprehensive Income/(Loss), net of tax, and were limited by the cumulative translation gain or loss on the net investment in the U.S. subsidiaries. For the three and nine months ended September 30, 2023, there were no unrealized foreign exchange gains or losses recorded in Other Comprehensive Income/(Loss) compared to unrealized losses of $24.3 million and $33.0 million, respectively, for the same periods in 2022, on Enerplus' U.S. dollar denominated senior notes and Bank Credit Facilities.

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

($ millions)	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Capital spending(1)	$ 121.4	$ 114.5	$ 440.9	$ 346.4
Office capital	1.3	0.2	2.6	0.6
Sub-total	122.7	114.7	443.5	347.0
Property and land acquisitions	2.3	16.3	5.7	19.7
Property and land divestments(1)	(1.6)	(4.2)	(1.7)	(19.4)
Sub-total	0.7	12.1	4.0	0.3
Total	$ 123.4	$ 126.8	$ 447.5	$ 347.3

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

Capital spending for the three and nine months ended September 30, 2023 totaled $121.4 million and $440.9 million, respectively, compared to $114.5 million and $346.4 million for the same periods in 2022. The increase was mainly due to increased capital activity on our North Dakota properties offset by minimal capital investment on our Marcellus natural gas properties.

Property and land acquisitions for the three and nine months ended September 30, 2023, were $2.3 million and $5.6 million, respectively, compared to $16.3 million and $19.7 million for the same periods in 2022. Property and land acquisitions during both periods were primarily related to the acquisition of interests in North Dakota.

Property and land divestments for the three and nine months ended September 30, 2023, were $1.6 million and $1.7 million, respectively, compared to $4.2 million and $19.4 million for the same periods in 2022. Property and land divestments for the nine months ended September 30, 2022 related to the sale of minor non-operated interests in North Dakota and Colorado.

We are narrowing our annual capital spending guidance range for 2023 to $520 - $540 million from $510 - $550 million.

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

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2023	2022	2023	2022
DD&A expense	$ 91.8	$ 82.2	$ 264.1	$ 219.0
Per BOE	$ 9.67	$ 8.29	$ 9.79	$ 8.18

DD&A related to PP&E is recognized using the unit of production method based on proved reserves. For the three and nine months ended September 30, 2023, Enerplus recorded DD&A expense of $91.8 million, or $9.67/BOE, and $264.1 million, or $9.79/BOE, respectively, compared to $82.2 million, or $8.29/BOE, and $219.0 million, or $8.18/BOE for the same periods in 2022. The increase was primarily a result of reserve additions and revisions at December 31, 2022 and subsequent capital spending in 2023.

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 $117.9 million at September 30, 2023, compared to $114.7 million at December 31, 2022.

For the three and nine months ended September 30, 2023, ARO settlements were $2.4 million and $11.3 million, respectively, compared to $1.6 million and $12.7 million during the same periods in 2022.

During 2022, Enerplus benefited from provincial government assistance to support the clean-up of inactive or abandoned crude oil and natural gas wells. These programs provided direct funding to oil field service contractors engaged by Enerplus to perform abandonment, remediation, and reclamation work. The funding received by the contractor was reflected as a reduction to ARO.

Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2023	2022	2023	2022
Current tax expense	$ 12.5	$ 7.9	$ 27.0	$ 24.9
Deferred tax expense	25.6	93.1	70.6	174.6
Total tax expense	$ 38.1	$ 101.0	$ 97.6	$ 199.5

For the three and nine months ended September 30, 2023, we recorded a current tax expense of $12.5 million and $27.0 million, respectively, compared to $7.9 million and $24.9 million for the same periods in 2022. Current tax expense in 2023 was higher compared to 2022 as a result of utilizing all of our net operating losses in 2022. Many factors influence taxable income, including future commodity prices, production levels, development activities, capital spending, and overall profitability. We continue to expect 2023 cash tax of 3.0% – 4.0% of adjusted funds flow before tax based on guidance pricing.

For the three and nine months ended September 30, 2023, we recorded a deferred income tax expense of $25.6 million and $70.6 million, respectively, compared to an expense of $93.1 million and $174.6 million for the same periods in 2022. Deferred tax expense was lower in 2023 compared to 2022 due to a decrease in net 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, 2023, 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 was $143.1 million, and the deferred income tax liability recorded in the U.S. was $114.1 million as at September 30, 2023. (December 31, 2022 - $155.0 million deferred income tax asset in Canada and $55.4 million deferred income tax liability in the U.S.).

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, 2023, our senior debt to adjusted EBITDA ratio was 0.2x and our net debt to adjusted funds flow ratio was 0.2x. 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, 2023 decreased to $212.1 million, compared to $221.5 million at December 31, 2022. Net debt was comprised of our senior notes and Bank Credit Facilities totaling $258.3 million, less cash on hand of $46.2 million.

At September 30, 2023, our Bank Credit Facilities totaled $1.3 billion, of which $135.7 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.

Our reinvestment rate[1] was 46% and 61% for the three and nine months ended September 30, 2023, respectively, compared to 32% and 38% for the same periods in 2022.

During the nine months ended September 30, 2023, a total of $200.8 million was returned to shareholders through share repurchases and dividends, compared to $271.3 million for the same period in 2022. During the nine months ended September 30, 2023, a total of 10.6 million common shares were repurchased and cancelled under the Normal Course Issuer Bid (“NCIB”) at an average price of $15.50 per share, for total consideration of $164.4 million. During the nine months ended September 30, 2022, a total of 18.1 million 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.

Subsequent to September 30, 2023 and up to November 1, 2023, we repurchased 2.5 million common shares under the NCIB at an average price of $16.65 per share, for total consideration of $40.9 million.

As previously announced, we plan to return at least 60% of second half 2023 free cash flow to shareholders through share repurchases and dividends, which is expected to result in over 70% of full year 2023 free cash flow returned. In conjunction with this plan, the Board of Directors approved a fourth quarter dividend of $0.06 per share to be paid in December 2023. The Company expects to continue to return significant free cash flow to shareholders in 2024 and anticipates its return of capital will equal approximately 70% of free cash flow. Based on current market conditions, the Company expects to continue to prioritize share repurchases for the majority of its return of capital plan. Remaining free cash flow not allocated to return of capital is expected to be directed to reinforcing the balance sheet.

At September 30, 2023, 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.sedarplus.ca.

[1] This financial measure is a supplementary financial measure. See “Non-GAAP Measures – Supplementary Financial Measures” section in this MD&A.

The following table lists our financial covenants at September 30, 2023:

Covenant Description		September 30, 2023
Bank Credit Facilities:	**Maximum Ratio**	
Senior debt to adjusted EBITDA	3.5x	0.2x
Total debt to adjusted EBITDA	4.0x	0.2x
Total debt to capitalization	55%	12%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA[(1)]	3.0x - 3.5x	0.2x
Senior debt to consolidated present value of total proved reserves[(2)]	60%	6%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	65.6x

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, 2023 was $282.5 million and $1,225.0 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)	2023	2022	2023	2022
Dividends	$ 12.6	$ 11.5	$ 36.4	$ 29.4
Per weighted average share (Basic)	$ 0.060	$ 0.050	$ 0.170	$ 0.126

During the three and nine months ended September 30, 2023, we declared total dividends of $12.6 million, or $0.06 per share, and $36.4 million, or $0.17 per share, respectively, compared to $11.5 million, or $0.05 per share, and $29.4 million, or $0.126 per share for the same periods in 2022. The total amount of dividends paid to shareholders has increased compared to the same period in 2022 due to the increased sustainability of the business and as a result of our current return of capital plan.

Subsequent to September 30, 2023, the Board of Directors approved a fourth quarter dividend of $0.06 per share to be paid in December 2023. We expect to fund the dividend through the free cash flow generated by the business.

Shareholders' Capital

	Nine months ended September 30,	
	2023	2022
Share capital ($ millions)	$ 2,745.6	$ 2,926.2
Common shares outstanding (thousands)	207,985	226,966
Weighted average shares outstanding – basic (thousands)	213,621	237,835
Weighted average shares outstanding – diluted (thousands)	220,093	245,403

For the nine months ended September 30, 2023, a total of 2.4 million units vested pursuant to our treasury-settled LTI plans, including the impact of performance multipliers (2022 – 2.2 million). In total, 1.3 million shares were issued from treasury and $7.3 million was transferred from paid-in capital to share capital (2022 – 1.2 million shares; $8.0 million). We elected to cash-settle the remaining units related to the required tax withholdings for the total amount of $16.5 million (2022 – $11.6 million).

On August 4, 2023, we filed a short form base shelf prospectus (the "Shelf Prospectus") with securities regulatory authorities in each of the provinces and territories of Canada and a Registration Statement with the U.S. Securities and Exchange Commission. The Shelf Prospectus allows us to offer and issue common shares, preferred shares, warrants, subscription receipts and units by way of one or more prospectus supplements during the 25-month period that the Shelf Prospectus remains valid.

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), or 21.0 million common shares, during a 12-month period. The Company completed its previous NCIB in July 2023.

During the nine months ended September 30, 2023, 10.6 million common shares were repurchased and cancelled under the NCIB at an average price of $15.50 per share, for total consideration of $164.4 million. Of the amount paid, $99.0 million was charged to share capital and $65.4 million was added to accumulated deficit.

During the nine months ended September 30, 2022, 18.1 million 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 added to accumulated deficit.

Subsequent to September 30, 2023 and up to November 1, 2023, we repurchased 2.5 million common shares under the NCIB at an average price of $16.65 per share, for total consideration of $40.9 million. At November 1, 2023, 15.8 million common shares remain available for repurchase under the current NCIB.

At November 1, 2023, we had 205,529,455 common shares outstanding. In addition, an aggregate of 7,991,418 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.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Crude Oil and Natural Gas Sales	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2023				
Third Quarter	$ 461.8	$ 127.7	$ 0.61	$ 0.59
Second Quarter	350.9	74.2	0.35	0.34
First Quarter	413.2	137.5	0.63	0.62
Total 2023	$ 1,226.0	$ 339.4	$ 1.59	$ 1.54
2022				
Fourth Quarter	$ 548.7	$ 330.7	$ 1.49	$ 1.43
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	$ 2,353.4	$ 914.3	$ 3.91	$ 3.77
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

Crude oil and natural gas sales increased to $461.8 million during the third quarter of 2023, compared to $350.9 million during the second quarter of 2023. We reported net income of $127.7 million during the third quarter of 2023 compared to net income of $74.2 million during the second quarter of 2023. The increase in crude oil and natural gas sales and net income was primarily due to higher commodity prices and higher crude oil and natural gas liquids production in the third quarter of 2023.

Crude oil and natural gas sales increased in 2022, compared to 2021, due to higher production and improved realized pricing. Net income increased in 2022, compared to 2021, due to higher production and commodity prices as well as the gain on the Canadian asset divestments recorded in the fourth quarter of 2022.

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, 2022.

2023 GUIDANCE[1]

Summary of 2023 Annual Expectations	Target
Capital spending ($ millions)	$520 to $540 (from $510 to $550)
Average annual production (BOE/day)	98,000 - 99,000 (from 94,500 - 98,500)
Average annual crude oil and natural gas liquids production (bbls/day)	60,500 - 61,500 (from 58,500 - 61,500)
Fourth quarter average production (BOE/day)	95,000 - 99,000
Fourth quarter average crude oil and natural gas liquids production (bbls/day)	60,500 - 64,500
Average production tax rate (% of gross sales, before transportation)	8%
Operating expenses (per BOE)	$10.75 - $11.00 (from $10.75 - $11.50)
Transportation costs (per BOE)	$4.05 (from $4.20)
Cash G&A expenses (per BOE)	$1.35
Current tax expense (% of adjusted funds flow before tax)	3% - 4%

Differential/Basis Outlook[2]	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	($0.25)/bbl (from $0.00/bbl)
Average Marcellus natural gas differential (compared to last day NYMEX natural gas)	($0.85)/Mcf (from ($0.75)/Mcf)

(1) This constitutes forward-looking information. Refer to “Forward-Looking Information and Statements” section in this MD&A.
(2) Excludes transportation costs.

NON-GAAP MEASURES

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

These non-GAAP financial measures and non-GAAP ratios do not have standardized meanings or definitions as prescribed by U.S. GAAP and may not be comparable with the calculation of similar financial measures by other entities.

For each measure, we have: (a) indicated the composition of the measure; (b) identified the most directly comparable GAAP financial measure and provided comparative detail where appropriate; (c) indicated the reconciliation of the measure to the most directly comparable GAAP financial measure to the extent one exists; and (d) 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).

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2023	2022	2023	2022
Net income/(loss)	**$ 127.7**	**$ 305.9**	**$ 339.4**	**$ 583.6**
Unrealized derivative instrument, foreign exchange and marketable securities (gain)/loss	15.6	(128.5)	32.0	(88.5)
Other expense/(income) related to investing activities	(1.4)	—	(1.4)	13.1
Tax effect	(4.7)	30.5	(7.7)	17.8
Adjusted net income/(loss)	**$ 137.2**	**$ 207.9**	**$ 362.3**	**$ 526.0**

“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)	2023	2022	2023	2022
Cash flow from/(used in) operating activities	$ 212.2	$ 409.9	$ 640.2	$ 856.8
Asset retirement obligation settlements	2.5	1.6	11.3	12.7
Changes in non-cash operating working capital	49.0	(55.9)	69.1	45.4
Adjusted funds flow	**$ 263.7**	**$ 355.6**	**$ 720.6**	**$ 914.9**
Capital spending	(121.4)	(114.5)	(440.9)	(346.4)
Free cash flow	**$ 142.3**	**$ 241.1**	**$ 279.7**	**$ 568.5**

“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)	2023	2022	2023	2022
Crude oil and natural gas sales	$ 461.8	$ 663.5	$ 1,226.0	$ 1,804.7
Less:				
Operating expenses	(96.6)	(103.8)	(278.5)	(270.5)
Transportation expenses	(36.7)	(41.3)	(108.9)	(114.9)
Production taxes	(40.0)	(48.2)	(98.8)	(127.4)
Netback before impact of commodity derivative contracts	**$ 288.5**	**$ 470.2**	**$ 739.8**	**$ 1,291.9**
Net realized gain/(loss) on derivative instruments	5.3	(88.5)	53.8	(299.8)
Netback after impact of commodity derivative contracts	**$ 293.8**	**$ 381.7**	**$ 793.6**	**$ 992.1**

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

We are required to comply with National Instrument 52-109 - Certification of Disclosure in Issuers' Annual and Interim Filings. This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to Enerplus' internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended September 30, 2023.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our Annual Information Form, is available under our profile on the SEDAR+ website at www.sedarplus.ca, 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: expectations regarding Enerplus' business, operations and financial condition in 2023 and beyond; 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; expected production volumes in 2023, including the production mix, and 2023 production guidance; 2023 capital spending guidance; expectations regarding free cash flow generation and long-term capital spending reinvestment rates; expected operating strategy in 2023; 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 2023; 2023 Bakken and Marcellus differential guidance; capital spending guidance; expectations regarding realized oil and natural gas prices; expected operating, transportation and cash G&A expenses and production taxes and 2023 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 2023 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; 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; 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; our ability to comply with our debt covenants; our ability to meet the targets associated with the Bank Credit Facilities; 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 2023 guidance described in this MD&A is based on rest of year commodity prices of: a WTI price of $80.00/bbl, a NYMEX price of $3.00/Mcf, 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 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, 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, as well as changes to the market conditions, that could impact our planned share repurchases and dividend levels, including the timing and sources of financing thereof; 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, 2022), which are available at www.sedarplus.ca, 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, 2023	December 31, 2022
Assets			
Current assets			
Cash and cash equivalents		$ 46,205	$ 38,000
Accounts receivable, net of allowance for doubtful accounts	12	305,991	276,590
Other current assets	4	57,332	56,552
Derivative financial assets	12	2,047	36,542
		411,575	407,684
Property, plant and equipment:			
Crude oil and natural gas properties (full cost method)	3	1,520,074	1,322,904
Other capital assets	3	9,501	10,685
Property, plant and equipment		1,529,575	1,333,589
Other long-term assets	4	7,028	21,154
Right-of-use assets		21,117	20,556
Deferred income tax asset	10	143,123	154,998
Total Assets		$ 2,112,418	$ 1,937,981
Liabilities			
Current liabilities			
Accounts payable		$ 375,806	$ 398,482
Current portion of long-term debt	5	80,600	80,600
Derivative financial liabilities	12	7,324	10,421
Current portion of lease liabilities		11,655	13,664
		475,385	503,167
Long-term debt	5	177,677	178,916
Asset retirement obligation	6	117,903	114,662
Lease liabilities		11,502	9,262
Deferred income tax liability	10	114,069	55,361
Total Liabilities		896,536	861,368
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: September 30, 2023 – 208 million shares			
December 31, 2022 – 217 million shares	11	2,745,597	2,837,329
Paid-in capital		43,887	50,457
Accumulated deficit		(1,272,261)	(1,509,832)
Accumulated other comprehensive loss		(301,341)	(301,341)
		1,215,882	1,076,613
Total Liabilities & Shareholders' Equity		$ 2,112,418	$ 1,937,981

Subsequent Event 11

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, 2023	Three months ended September 30, 2022	Nine months ended September 30, 2023	Nine months ended September 30, 2022
Revenues					
Crude oil and natural gas sales	7	$ 461,836	$ 663,532	$ 1,225,957	$ 1,804,701
Commodity derivative instruments gain/(loss)	12	(14,602)	56,995	20,324	(197,368)
		447,234	720,527	1,246,281	1,607,333
Expenses					
Operating		96,573	103,841	278,493	270,451
Transportation		36,745	41,312	108,946	114,949
Production taxes		39,959	48,169	98,847	127,351
General and administrative	8	18,862	15,745	53,368	48,013
Depletion, depreciation and accretion		91,825	82,225	264,051	219,006
Interest		4,832	6,471	12,742	18,624
Foreign exchange (gain)/loss	9	641	16,109	(250)	13,764
Other expense/(income)	4, 6	(7,935)	(368)	(6,873)	12,020
		281,502	313,504	809,324	824,178
Income/(Loss) Before Taxes		165,732	407,023	436,957	783,155
Current income tax expense/(recovery)	10	12,500	7,929	27,000	24,929
Deferred income tax expense/(recovery)	10	25,577	93,149	70,583	174,632
Net Income/(Loss)		$ 127,655	$ 305,945	$ 339,374	$ 583,594
Other Comprehensive Income/(Loss)					
Unrealized gain/(loss) on foreign currency translation	12	—	28,582	—	29,939
Foreign exchange gain/(loss) on net investment hedge, net of tax	12	—	(24,276)	—	(32,995)
Total Comprehensive Income/(Loss)		$ 127,655	$ 310,251	$ 339,374	$ 580,538
Net Income/(Loss) per Share					
Basic	11	$ 0.61	$ 1.32	$ 1.59	$ 2.47
Diluted	11	$ 0.59	$ 1.28	$ 1.54	$ 2.40

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, 2023	Three months ended September 30, 2022	Nine months ended September 30, 2023	Nine months ended September 30, 2022
Share Capital				
Balance, beginning of period	$ 2,776,088	$ 3,001,604	$ 2,837,329	$ 3,094,061
Purchase of common shares under Normal Course Issuer Bid	(30,520)	(75,387)	(99,023)	(175,803)
Share-based compensation – treasury settled	29	—	7,291	7,959
Balance, end of period	$ 2,745,597	$ 2,926,217	$ 2,745,597	$ 2,926,217
Paid-in Capital				
Balance, beginning of period	$ 38,963	$ 41,843	$ 50,457	$ 50,881
Share-based compensation – tax withholdings settled in cash	(50)	—	(16,470)	(11,567)
Share-based compensation – treasury settled	(29)	—	(7,291)	(7,959)
Share-based compensation – non-cash	5,003	3,765	17,191	14,253
Balance, end of period	$ 43,887	$ 45,608	$ 43,887	$ 45,608
Accumulated Deficit				
Balance, beginning of period	$ (1,362,697)	$ (2,008,253)	$ (1,509,832)	$ (2,238,325)
Net income/(loss)	127,655	305,945	339,374	583,594
Purchase of common shares under Normal Course Issuer Bid	(24,607)	(36,413)	(65,442)	(66,132)
Dividends declared(1)	(12,612)	(11,516)	(36,361)	(29,374)
Balance, end of period	$ (1,272,261)	$ (1,750,237)	$ (1,272,261)	$ (1,750,237)
Accumulated Other Comprehensive Income/(Loss)				
Balance, beginning of period	$ (301,341)	$ (304,669)	$ (301,341)	$ (297,307)
Unrealized gain/(loss) on foreign currency translation	—	28,582	—	29,939
Foreign exchange gain/(loss) on net investment hedge, net of tax	—	(24,276)	—	(32,995)
Balance, end of period	$ (301,341)	$ (300,363)	$ (301,341)	$ (300,363)
Total Shareholders’ Equity	$ 1,215,882	$ 921,225	$ 1,215,882	$ 921,225

(1) For the three and nine months ended September 30, 2023, dividends declared were $0.060 per share and $0.170 per share, respectively (2022 – $0.050 per share and $0.126 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, 2023	Three months ended September 30, 2022	Nine months ended September 30, 2023	Nine months ended September 30, 2022
Operating Activities					
Net income/(loss)		$ 127,655	$ 305,945	$ 339,374	$ 583,594
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		91,825	82,225	264,051	219,006
Changes in fair value of derivative instruments	12	19,924	(145,480)	33,515	(103,423)
Deferred income tax expense/(recovery)	10	25,577	93,149	70,583	174,632
Unrealized foreign exchange (gain)/loss on working capital	9	679	16,997	(33)	14,876
Share-based compensation and general and administrative	8, 11	4,881	3,665	16,869	13,959
Other expense/(income)	4	(5,411)	(289)	(2,322)	12,267
Amortization of debt issuance costs	5	388	366	1,176	1,070
Translation of U.S. dollar cash held in parent company	9	—	(956)	—	(1,071)
Investing activities in Other income		(1,834)	—	(2,496)	—
Asset retirement obligation settlements	6	(2,448)	(1,560)	(11,318)	(12,704)
Changes in non-cash operating working capital	13	(48,991)	55,884	(69,155)	(45,408)
Cash flow from/(used in) operating activities		212,245	409,946	640,244	856,798
Financing Activities					
Drawings from/(repayment of) bank credit facilities	5	42,172	(130,315)	79,361	(186,015)
Repayment of senior notes	5	(21,000)	(21,000)	(80,600)	(100,600)
Purchase of common shares under Normal Course Issuer Bid	11	(55,127)	(111,800)	(164,465)	(241,935)
Share-based compensation – tax withholdings settled in cash	11	(50)	—	(16,470)	(11,567)
Dividends	11	(12,612)	(11,516)	(36,361)	(29,374)
Cash flow from/(used in) financing activities		(46,617)	(274,631)	(218,535)	(569,491)
Investing Activities					
Capital and office expenditures	13	(170,635)	(121,382)	(439,440)	(311,449)
Canadian divestments	4, 13	15,128	—	27,362	—
Property and land acquisitions		(2,275)	(16,252)	(5,661)	(19,662)
Property and land divestments		1,563	4,214	4,202	6,333
Cash flow from/(used in) investing activities		(156,219)	(133,420)	(413,537)	(324,778)
Effect of exchange rate changes on cash and cash equivalents		(679)	14,884	33	18,308
Change in cash and cash equivalents		8,730	16,779	8,205	(19,163)
Cash and cash equivalents, beginning of period		37,475	25,406	38,000	61,348
Cash and cash equivalents, end of period		$ 46,205	$ 42,185	$ 46,205	$ 42,185

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 production 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, 2023 and the 2022 comparative periods. 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, 2022.

The functional currency of the parent company changed from Canadian dollars to U.S. dollars effective January 1, 2023. This was the result of a gradual change in the primary economic environment in which the entity operates, culminating in the sale of Enerplus' remaining Canadian operating assets at the end of 2022. This has triggered a prospective change as of January 1, 2023 in functional currency of the parent entity to U.S. dollars, consistent with the functional currency of its U.S. subsidiaries. All assets and liabilities held by the parent company were translated at the exchange rate at December 31, 2022 to determine opening balances in U.S. dollars. Amounts that are part of Shareholders' Equity of the parent company are translated at historical exchange rates. Monetary assets and liabilities denominated in Canadian dollars will be revalued at current exchange rates at each reporting period. Upon settlement and/or realization of Canadian dollar denominated assets and liabilities, there may be realized foreign exchange gains and losses depending on the change in the foreign exchange rate when the transaction was originally recorded and the final settlement date.

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.

In preparing these financial statements, Enerplus is required to make estimates and assumptions and use judgement. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates and judgement used in the preparation of the financial statements are described in the Company's annual audited Consolidated Financial Statements as of December 31, 2022.

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

At September 30, 2023 ($ thousands)	**Cost**	**Accumulated Depletion, Depreciation, and Impairment**	**Net Book Value**
Crude oil and natural gas properties[1]	$ 7,661,991	$ (6,141,917)	$ 1,520,074
Other capital assets	101,314	(91,813)	9,501
Total PP&E	$ 7,763,305	$ (6,233,730)	$ 1,529,575

At December 31, 2022 ($ thousands)	**Cost**	**Accumulated Depletion, Depreciation, and Impairment**	**Net Book Value**
Crude oil and natural gas properties[1]	$ 7,214,993	$ (5,892,089)	$ 1,322,904
Other capital assets	99,283	(88,598)	10,685
Total PP&E	$ 7,314,276	$ (5,980,687)	$ 1,333,589

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

4) DIVESTMENTS

In the fourth quarter of 2022, the Company divested substantially all of its Canadian assets in two transactions for total adjusted proceeds of $213.0 million after purchase price adjustments and transaction costs. These transactions resulted in a $151.9 million gain on asset divestments on the Consolidated Statements of Income/(Loss) in the fourth quarter of 2022.

At September 30, 2023, the current and long-term portion of the outstanding loan receivable from one of the purchasers of $15.8 million and $1.2 million, respectively (December 31, 2022 – $17.7 million and $13.4 million, respectively), have been recorded as part of Other current assets and Other long-term assets on the Condensed Consolidated Balance Sheets.

At September 30, 2023, the common shares of one of the purchasers had a fair value of $19.0 million (December 31, 2022 – $23.1 million). The fair value of the marketable securities has been recorded as part of Other current assets on the Condensed Consolidated Balance Sheets.

5) DEBT

($ thousands)	September 30, 2023	December 31, 2022
Current:		
Senior notes	$ 80,600	$ 80,600
Long-term:		
Bank credit facilities	135,677	56,316
Senior notes	42,000	122,600
Total debt	$ 258,277	$ 259,516

Bank Credit Facilities

Enerplus has two senior unsecured, covenant-based, sustainability linked lending ("SLL") bank credit facilities. The first is a $900 million facility with $50 million maturing on October 31, 2025 and $850 million maturing on October 31, 2026. The second facility for $365 million matures on October 31, 2025. Debt issuance costs of $2.0 million in relation to the SLL bank credit facilities were netted against the bank credit facilities at September 30, 2023. For the three and nine months ended September 30, 2023, total amortization of debt issuance costs amounted to $0.4 million and $1.2 million, respectively (2022 – $0.4 million and $1.1 million, respectively).

Senior Notes

During the three months ended September 30, 2023, Enerplus made a $21.0 million principal repayment on its 2014 senior notes. In addition, during the nine months ended September 30, 2023, Enerplus made its fourth $59.6 million principal repayment on its 2012 senior notes. 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	3 equal annual installments beginning September 3, 2024	3.79%	$200,000	$63,000
May 15, 2012	May 15 and Nov 15	1 final installment on May 15, 2024	4.40%	$355,000	$59,600
				Total carrying value at September 30, 2023	$ 122,600

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, 2023	December 31, 2022
Current portion of long-term debt	$ 80,600	$ 80,600
Long-term debt	177,677	178,916
Total debt	$ 258,277	$ 259,516
Less: Cash and cash equivalents	(46,205)	(38,000)
Net debt	$ 212,072	$ 221,516

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)	2023	2022	2023	2022
Cash flow from/(used in) operating activities	$ 212,245	$ 409,946	$ 640,244	$ 856,798
Asset retirement obligation settlements	2,448	1,560	11,318	12,704
Changes in non-cash operating working capital	48,991	(55,884)	69,155	45,408
Adjusted funds flow	$ 263,684	$ 355,622	$ 720,717	$ 914,910

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, 2023	December 31, 2022
Net debt	$ 212,072	$ 221,516
Trailing adjusted funds flow	1,036,096	1,230,289
Net debt to adjusted funds flow ratio	0.2x	0.2x

6) ASSET RETIREMENT OBLIGATION (“ARO”)

($ thousands)	September 30, 2023	December 31, 2022
Balance, beginning of year	$ 114,662	$ 132,814
Change in estimates	6,538	48,419
Property acquisition and development activity	3,920	3,985
Divestments	—	(58,284)
Settlements	(11,318)	(17,401)
Government assistance	—	(1,744)
Accretion expense	4,101	6,873
Balance, end of period	$ 117,903	$ 114,662

Enerplus has estimated the present value of its ARO to be $117.9 million at September 30, 2023 based on a total undiscounted uninflated liability of $272.3 million (December 31, 2022 – $114.7 million and $262.4 million, respectively).

During 2022, Enerplus benefited from provincial government assistance to support the clean-up of inactive or abandoned crude oil and natural gas wells. These programs provided direct funding to oil field service contractors engaged by Enerplus to perform abandonment, remediation, and reclamation work. The funding received by the contractor was reflected as a reduction to ARO.

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

7) CRUDE OIL AND NATURAL GAS SALES

Crude oil and natural gas sales by country and by product for the three and nine months ended September 30, 2023 and 2022 are as follows:

Three months ended September 30, 2023 ($ thousands)	**Total revenue**	**Crude oil[1]**	**Natural gas[1]**	**Natural gas liquids and other[1][2]**
United States	$ 461,836	$ 412,149	$ 27,707	$ 21,980

Three months ended September 30, 2022 ($ thousands)	**Total revenue**	**Crude oil[1]**	**Natural gas[1]**	**Natural gas liquids and other[1][2]**
United States	$ 626,746	$ 456,385	$ 139,575	$ 30,786
Canada	36,786	32,684	2,593	1,509
Total	$ 663,532	$ 489,069	$ 142,168	$ 32,295

Nine months ended September 30, 2023 ($ thousands)	**Total revenue**	**Crude oil[1]**	**Natural gas[1]**	**Natural gas liquids and other[1][2]**
United States	$ 1,225,957	$ 1,051,339	$ 120,035	$ 54,583

Nine months ended September 30, 2022 ($ thousands)	**Total revenue**	**Crude oil[1]**	**Natural gas[1]**	**Natural gas liquids and other[1][2]**
United States	$ 1,677,253	$ 1,247,816	$ 347,043	$ 82,394
Canada	127,448	112,680	9,855	4,913
Total	$ 1,804,701	$ 1,360,496	$ 356,898	$ 87,307

(1) U.S. sales of crude oil, natural gas and natural gas liquids relate primarily to the Company's North Dakota and Marcellus properties. Canadian crude oil sales relate primarily to the Company's waterflood properties in 2022. Substantially all of the Canadian assets were disposed of in the fourth quarter of 2022.

(2) Includes third party processing income of nil for the three and nine months ended September 30, 2023 (2022 – $0.2 million and $0.5 million, respectively).

8) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	Three months ended September 30, 2023	Three months ended September 30, 2022	Nine months ended September 30, 2023	Nine months ended September 30, 2022
General and administrative expense excluding share-based compensation[1]	$ 11,957	$ 10,797	$ 35,122	$ 31,191
Share-based compensation expense	6,905	4,948	18,246	16,822
General and administrative expense	$ 18,862	$ 15,745	$ 53,368	$ 48,013

(1) Includes a non-cash lease credit of $122 and $322 for the three and nine months ended September 30, 2023 (2022 – credit of $100 and $294, respectively).

9) FOREIGN EXCHANGE

($ thousands)	Three months ended September 30, 2023	Three months ended September 30, 2022	Nine months ended September 30, 2023	Nine months ended September 30, 2022
Realized:				
Foreign exchange (gain)/loss	$ (38)	$ 68	$ (217)	$ (41)
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company	—	(956)	—	(1,071)
Unrealized:				
Foreign exchange (gain)/loss on Canadian dollar working capital in parent company	679	—	(33)	—
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company	—	16,997	—	14,876
Foreign exchange (gain)/loss	$ 641	$ 16,109	$ (250)	$ 13,764

10) INCOME TAXES

($ thousands)	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Current tax				
United States	$ 12,500	$ 7,929	$ 27,000	$ 24,929
Canada	—	—	—	—
Current tax expense/(recovery)	12,500	7,929	27,000	24,929
Deferred tax				
United States	$ 24,804	$ 43,328	$ 58,708	$ 173,694
Canada	773	49,821	11,875	938
Deferred tax expense/(recovery)	25,577	93,149	70,583	174,632
Income tax expense/(recovery)	$ 38,077	$ 101,078	$ 97,583	$ 199,561

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 was $143.1 million and the deferred income tax liability recorded in the U.S. was $114.1 million at September 30, 2023 (December 31, 2022 – $155.0 million deferred income tax asset in Canada and $55.4 million deferred income tax liability in the U.S.).

11) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized unlimited number of common shares issued: (thousands)	Nine months ended September 30, 2023 Shares	Amount	Year ended December 31, 2022 Shares	Amount
Balance, beginning of year	217,285	$ 2,837,329	243,852	$ 3,094,061
Issued/(Purchased) for cash:				
Purchase of common shares under Normal Course Issuer Bid	(10,611)	(99,023)	(27,925)	(266,694)
Non-cash:				
Share-based compensation – treasury settled(1)	1,311	7,291	1,358	9,962
Balance, end of period	207,985	$ 2,745,597	217,285	$ 2,837,329

(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, 2023 were $12.6 million and $36.4 million, respectively (2022 – $11.5 million and $29.4 million, respectively).

On August 4, 2023, the Company filed a short form base shelf prospectus (the "Shelf Prospectus") with securities regulatory authorities in each of the provinces and territories of Canada and a Registration Statement with the U.S. Securities and Exchange Commission. The Shelf Prospectus allows Enerplus to offer and issue common shares, preferred shares, warrants, subscription receipts and units by way of one or more prospectus supplements during the 25-month period that the Shelf Prospectus remains valid.

On August 17, 2023, 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 2023.

During the three months ended September 30, 2023, 3.3 million common shares were repurchased and cancelled under the NCIB at an average price of $16.85 per share, for total consideration of $55.1 million. Of the amount paid, $30.5 million was charged to share capital and $24.6 million was added to accumulated deficit. During the nine months ended September 30, 2023, 10.6 million common shares were repurchased and cancelled under the NCIB at an average price of $15.50 per share, for total consideration of $164.4 million. Of the amount paid, $99.0 million was charged to share capital and $65.4 million was added to accumulated deficit.

During the three months ended September 30, 2022, 7.9 million 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 added to accumulated deficit. During the nine months ended September 30, 2022, 18.1 million 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 added to accumulated deficit.

Subsequent to September 30, 2023, and up to November 1, 2023, the Company repurchased 2.5 million common shares under the NCIB at an average price of $16.65 per share, for total consideration of $40.9 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):

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2023	2022	2023	2022
Cash:				
Long-term incentive plans (recovery)/expense	$ 1,902	$ 1,183	$ 1,055	$ 3,577
Non-Cash:				
Long-term incentive plans (recovery)/expense	5,003	3,765	17,191	14,253
Equity swap (gain)/loss	—	—	—	(1,008)
Share-based compensation expense	$ 6,905	$ 4,948	$ 18,246	$ 16,822

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, 2023:

	Cash-settled LTI plans	Equity-settled LTI plans		
(thousands of units)	DSU/DRSU	PSU(1)	RSU	Total
Balance, beginning of year	633	3,689	2,321	6,643
Granted	79	512	493	1,084
Vested	(170)	(996)	(1,200)	(2,366)
Forfeited	—	—	(33)	(33)
Balance, end of period	542	3,205	1,581	5,328

(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, 2023, the Company recorded a cash share-based compensation expense of $1.9 million and $1.1 million, respectively (2022 –$1.2 million and $3.6 million expense, respectively).

At September 30, 2023, a liability of $9.5 million (December 31, 2022 – $11.1 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, 2023 ($ thousands, except for years)	PSU[1]	RSU	Total
Cumulative recognized share-based compensation expense	$ 24,877	$ 15,552	$ 40,429
Unrecognized share-based compensation expense	7,744	5,494	13,238
Fair value	$ 32,621	$ 21,046	$ 53,667
Weighted-average remaining contractual term (years)	1.1	1.2	

(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, 2023, $0.1 million and $16.5 million, respectively (2022 – nil and $11.6 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)	2023	2022	2023	2022
Net income/(loss)	$ 127,655	$ 305,945	$ 339,374	$ 583,594
Weighted average shares outstanding – Basic	210,337	231,565	213,621	237,835
Dilutive impact of share-based compensation	6,520	7,571	6,472	7,568
Weighted average shares outstanding – Diluted	216,857	239,136	220,093	245,403
Net income/(loss) per share				
Basic	$ 0.61	$ 1.32	$ 1.59	$ 2.47
Diluted	$ 0.59	$ 1.28	$ 1.54	$ 2.40

12) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At September 30, 2023, 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, 2023, the senior notes had a carrying value of $122.6 million and a fair value of $113.4 million (December 31, 2022 – $203.2 million and $189.5 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.

At September 30, 2023, the loan receivable had a carrying value and fair value of $17.0 million (December 31, 2022 – $31.1 million and $31.6 million, respectively). The fair value of the loan receivable is estimated based on the amount that Enerplus would receive from a third party to assume the loan, including the difference between the coupon rate and the period end market rate for loan receivables of similar terms and credit risk.

The fair value of marketable securities are considered level 1 fair value measurements, while the derivative contracts, senior notes, bank credit facilities and loan receivable 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.

The following table summarizes the change in fair value associated with equity and commodity contracts for the three and nine months ended September 30, 2023 and 2022:

	Three months ended September 30,		Nine months ended September 30,		
Unrealized Gain/(Loss) ($ thousands)	**2023**	**2022**	**2023**	**2022**	**Income Statement Presentation**
Equity Swaps	$ —	$ —	$ —	$ 1,008	G&A expense
Commodity Contracts:					
Crude oil	(14,003)	125,978	(8,780)	98,785	Commodity derivative instruments
Natural gas	(5,921)	19,502	(24,735)	3,630	
Total unrealized gain/(loss)	$ (19,924)	$ 145,480	$ (33,515)	$ 103,423	

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)	**2023**	**2022**	**2023**	**2022**
Unrealized change in fair value gain/(loss)	$ (19,924)	$ 145,480	$ (33,515)	$ 102,415
Net realized cash gain/(loss)	5,322	(88,485)	53,839	(299,783)
Commodity contracts gain/(loss)	$ (14,602)	$ 56,995	$ 20,324	$ (197,368)

The following table summarizes the presentation of fair values on the Condensed Consolidated Balance Sheets:

	September 30, 2023		December 31, 2022	
	Assets	**Liabilities**	**Assets**	**Liabilities**
($ thousands)	**Current**	**Current**	**Current**	**Current**
Commodity Contracts:				
Crude oil	$ 74	$ 7,324	$ 9,834	$ 10,421
Natural gas	1,973	—	26,708	—
Total	$ 2,047	$ 7,324	$ 36,542	$ 10,421

The fair value of commodity contracts 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.

At September 30, 2023, the fair value of Enerplus' commodity contracts totaled a net liability of $5.3 million (December 31, 2022 – net asset of $26.1 million).

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 September 30, 2023, and positions entered into subsequent to September 30, 2023 and up to November 1, 2023:

Crude Oil Instruments:

Instrument Type[(1)(2)]	**Oct 1, 2023 – Oct 31, 2023**		**Nov 1, 2023 – Dec 31, 2023**		**Jan 1, 2024 – Jun 30, 2024**	
	bbls/day	**$/bbl**	**bbls/day**	**$/bbl**	**bbls/day**	**$/bbl**
WTI Purchased Put	10,000	81.00	10,000	81.00	5,000	77.00
WTI Sold Put	10,000	65.00	10,000	65.00	5,000	65.00
WTI Sold Call	10,000	111.58	10,000	111.58	5,000	95.00
Brent – WTI Spread	10,000	5.47	10,000	5.47	—	—
WTI Purchased Swap	250	64.85	—	—	—	—
WTI Sold Swap[(3)]	250	42.10	—	—	—	—
WTI Purchased Put[(3)]	2,000	5.00	2,000	5.00	—	—
WTI Sold Call[(3)]	2,000	75.00	2,000	75.00	—	—

(1) The total average deferred premium spent on the Company's outstanding crude oil contracts is $1.19/bbl from October 1, 2023 – June 30, 2024.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Outstanding commodity derivative instruments acquired as part of the Company's acquisition of Bruin E&P Holdco, LLC completed in 2021.

Natural Gas Instruments:

Instrument Type[(1)]	**Oct 1, 2023 – Oct 31, 2023**	
	MMcf/day	**$/Mcf**
NYMEX Purchased Put	50.0	4.05
NYMEX Sold Call	50.0	7.00

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

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk as it relates to certain activities transacted in Canadian dollars. The parent company and its subsidiaries have a U.S. dollar functional currency, and the parent company has both U.S. and Canadian dollar transactions. Canadian denominated monetary assets and liabilities are subject to revaluation from the source currency of Canadian dollars to the functional currency of U.S. dollars, generating realized and unrealized foreign exchange (gains)/losses in the Condensed Consolidated Statements of Income/(Loss).

Following the change in functional currency of the parent company to U.S. dollars on January 1, 2023, the net investment hedge on the U.S. dollar denominated debt held in the parent entity for the U.S. subsidiaries was no longer required. Previously, the unrealized foreign exchange gains and losses arising from the translation of the debt were recorded in Other Comprehensive Income/(Loss), net of tax, and were limited by the cumulative translation gain or loss on the net investment in the U.S. subsidiaries. For the three and nine months ended September 30, 2023, there were no unrealized foreign exchange gains or losses recorded in Other Comprehensive Income/(Loss) compared to an unrealized loss of $24.3 million and $33.0 million, respectively on Enerplus' U.S. denominated senior notes and bank credit facilities for the three and nine months ended September 30, 2022.

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, 2023, approximately 47% of Enerplus' debt was based on fixed interest rates and 53% on floating interest rates (December 31, 2022 – 78% fixed and 22% floating), with a weighted average interest rates of 4.1% and 6.6%, respectively (December 31, 2022 – 4.1% and 5.7%, respectively). At September 30, 2023, 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 11. 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, 2023 and December 31, 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, divestments 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, 2023, approximately 90% of Enerplus' marketing receivables were with companies considered investment grade (December 31, 2022 – 90%).

Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off 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, 2023 was $2.9 million (December 31, 2022 – $2.9 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, 2023, 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. There have been no material changes since management's risk assessment at December 31, 2022.

13) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	Three months ended September 30, 2023	Three months ended September 30, 2022	Nine months ended September 30, 2023	Nine months ended September 30, 2022
Accounts receivable	$ (68,223)	$ 73,456	$ (32,507)	$ (86,627)
Other assets – operating	(3,233)	(2,575)	6,057	2,217
Accounts payable – operating	22,465	(14,997)	(42,705)	39,002
Non-cash operating activities	$ (48,991)	$ 55,884	$ (69,155)	$ (45,408)

b) Changes in Non-Cash Investing Working Capital

($ thousands)	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Accounts payable – investing[1]	$ (47,940)	$ (6,750)	$ 16,553	$ 35,540
Other current assets – investing[1]	—	—	(12,439)	—
Non-cash investing activities	$ (47,940)	$ (6,750)	$ 4,114	$ 35,540

(1) Relates to changes in Accounts payable and Other current assets for capital and office expenditures and included in Capital and office expenditures on the Condensed Consolidated Statements of Cash Flows.

($ thousands)	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Settlement on divestment[1]	$ —	$ —	$ —	$ 13,053

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

($ thousands)	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Loan receivable	$ 5,509	$ —	$ 14,985	$ —
Accounts receivable	1,966	—	3,128	—
Other current assets	5,524	—	5,524	—
Non-cash working capital – Canadian divestments[1]	$ 12,999	$ —	$ 23,637	$ —

(1) Refer to Note 4.

c) Cash Income Taxes and Interest Payments

($ thousands)	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Income taxes paid	$ 5,026	$ 17,657	$ 20,260	$ 20,271
Interest paid	$ 4,853	$ 5,056	$ 11,962	$ 17,455

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(4)(7)(9)
Corporate Director
Toronto, Ontario

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

Mark A. Houser(5)(7)(10)
Corporate Director
Houston, Texas

Ward M. Polzin(5)(7)
Corporate Director
Denver, Colorado

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

Sheldon B. Steeves(3)(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 & Midstream

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

Subramanian L. Madhavarao
Vice President, Digital Technology

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
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New York Stock Exchange: ERF

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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
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
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
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

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