enerPLUS

SECOND QUARTER REPORT
6 months ended June 30, 2023

SELECTED FINANCIAL RESULTS	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Financial (US$, thousands, except ratios)				
Net Income/(Loss)	$ 74,233	$244,406	$211,719	$277,649
Adjusted Net Income[1]	84,405	172,251	225,151	318,079
Cash Flow from Operating Activities	186,598	250,860	427,999	446,852
Adjusted Funds Flow	196,624	297,393	457,033	559,288
Dividends to Shareholders - Declared	11,756	9,940	23,749	17,858
Net Debt	199,630	545,983	199,630	545,983
Capital Spending	180,942	132,884	319,590	231,898
Property and Land Acquisitions	1,638	1,469	3,386	3,410
Property and Land Divestments	(94)	8,591	139	15,172
Net Debt to Adjusted Funds Flow Ratio	0.2x	0.5x	0.2x	0.5x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ 0.35	$ 1.01	$ 0.98	$ 1.15
Net Income/(Loss) - Diluted	0.34	0.99	0.96	1.12
Weighted Average Number of Shares Outstanding (000's) - Basic	213,790	239,277	215,289	241,022
Weighted Average Number of Shares Outstanding (000's) - Diluted	219,732	247,216	221,276	248,957
Selected Financial Results per BOE[2][3]				
Crude Oil & Natural Gas Sales[4]	$ 40.35	$ 73.31	$ 43.70	$ 67.67
Commodity Derivative Instruments	1.63	(16.13)	2.77	(12.53)
Operating Expenses	(10.25)	(9.74)	(10.40)	(9.88)
Transportation Costs	(3.96)	(4.41)	(4.13)	(4.36)
Production Taxes	(3.31)	(5.11)	(3.37)	(4.70)
General and Administrative Expenses	(1.20)	(1.10)	(1.34)	(1.22)
Cash Share-Based Compensation	(0.01)	(0.04)	0.05	(0.14)
Interest, Foreign Exchange and Other Expenses	(0.24)	(0.67)	(0.31)	(0.67)
Current Income Tax Expense	(0.40)	(1.40)	(0.83)	(1.01)
Adjusted Funds Flow	$ 22.61	$ 34.71	$ 26.14	$ 33.16

SELECTED OPERATING RESULTS	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Average Daily Production[3]				
Crude Oil (bbls/day)	47,430	48,213	47,399	47,925
Natural Gas Liquids (bbls/day)	10,784	8,653	10,079	8,516
Natural Gas (Mcf/day)	224,149	223,653	234,770	220,400
Total (BOE/day)	95,572	94,142	96,606	93,174
% Crude Oil and Natural Gas Liquids	61%	60%	59%	61%
Average Selling Price[3][4]				
Crude Oil (per bbl)	$ 72.69	$ 108.77	$ 74.50	$ 100.46
Natural Gas Liquids (per bbl)	15.49	33.31	17.83	35.49
Natural Gas (per Mcf)	1.08	6.11	2.17	5.38
Net Wells Drilled	21.8	16.5	37.4	31.7

(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 June 30, 2023	Three months ended June 30, 2022	Six months ended June 30, 2023	Six months ended June 30, 2022
WTI Crude Oil ($/bbl)	$ 73.78	$ 108.41	$ 74.96	$ 101.35
Brent (ICE) Crude Oil ($/bbl)	78.01	111.78	80.12	104.58
Propane – Conway ($/bbl)	27.70	51.16	30.34	52.59
NYMEX Natural Gas – Last Day ($/Mcf)	2.10	7.17	2.76	6.06
CDN/US Average Exchange Rate	0.74	0.78	0.74	0.79

Share Trading Summary For the three months ended June 30, 2023	U.S.(1) – ERF (US$)	CDN(2) – ERF (CDN$)
High	$ 15.61	$ 20.93
Low	$ 13.73	$ 18.21
Close	$ 14.47	$ 19.15

(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
Total Year to Date	$ 0.110	$ 0.150

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

NEWS RELEASE

HIGHLIGHTS

- Second quarter production averaged 95.6 MBOE per day, including 58.2 Mbbl per day of liquids
- Production per share increased by 14% in the second quarter of 2023 compared to the same period in 2022
- Total production guidance for full-year 2023 was increased to 94.5 – 98.5 MBOE per day (from 93.0 – 98.0 MBOE per day), with liquids production guidance increased to 58.5 – 61.5 Mbbl per day (from 57.0 – 61.0 Mbbl per day) due to strong well performance
- Robust oil production growth is anticipated in the second half of 2023: approximately 10% liquids production growth is expected in the third quarter compared to the second quarter
- Returned $66.5 million to shareholders in the second quarter through dividends and share repurchases. Through the first half of 2023, Enerplus returned $133.1 million to shareholders, representing 97% of free cash flow[1]
- Planning to return at least 60% of second half 2023 free cash flow to shareholders which is expected to result in over 70% of full-year 2023 free cash flow returned to shareholders, based on current commodity prices
- Increased quarterly dividend by 9% to $0.06 per share
- Normal course issuer bid ("NCIB") was completed having repurchased the maximum 10% of the public float between August 2022 and July 2023. The Company plans to renew its NCIB in August 2023 for another 10% of the public float
- Capital spending guidance range for 2023 was narrowed to $510 – $550 million (from $500 – $550 million)

"Enerplus' second quarter results and updated 2023 outlook reflect our strong operating momentum," said Ian C. Dundas, President and CEO. "Our setup for the second half of 2023 is compelling. We anticipate robust oil production growth and a free cash flow profile that is approximately double what we generated during the first half of the year. With this outlook and our strong financial position, we plan to continue to return a meaningful proportion of free cash flow to shareholders through the balance of the year."

SECOND QUARTER SUMMARY

Production in the second quarter of 2023 was 95,572 BOE per day, a decrease of 2% compared to the first quarter of 2023 and 2% higher than the same period a year ago. Crude oil and natural gas liquids production in the second quarter of 2023 was 58,214 barrels per day, an increase of 3% and 2% compared to the prior quarter and the same period a year ago, respectively. The increased production compared to the same period in 2022 was primarily driven by new wells online in North Dakota, partially offset by lower natural gas production in the Marcellus due to limited capital activity in 2023, and was despite the sale of the Company's Canadian assets in the fourth quarter of 2022.

Enerplus reported second quarter 2023 net income of $74.2 million, or $0.35 per share (basic), compared to net income of $244.4 million, or $1.01 per share (basic), in the same period in 2022. Adjusted net income[1] for the second quarter of 2023 was $84.4 million, or $0.39 per share (basic), compared to $172.3 million, or $0.72 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 higher commodity prices during the second quarter of 2022.

Enerplus' second quarter 2023 realized Bakken oil price differential was $0.71 per barrel below WTI, compared to $0.85 per barrel above WTI in the second quarter of 2022. The weaker realized differential was due to lower prices for crude oil delivered to markets in both North Dakota and the U.S. Gulf Coast primarily due to weaker U.S. refinery margins early in the quarter. U.S. refinery utilization recovered later in the second quarter supported by resilient domestic product demand. Enerplus expects its annual realized Bakken crude oil price differential to be at par with WTI (prior guidance was $0.50 per barrel above WTI).

The Company's realized Marcellus natural gas price differential was $0.68 per Mcf below NYMEX during the second quarter of 2023, compared to $0.59 per Mcf below NYMEX in the second quarter of 2022. Enerplus continues to expect its 2023 Marcellus natural gas price differential to average $0.75 per Mcf below NYMEX.

In the second quarter of 2023, Enerplus' operating costs were $10.25 per BOE, compared to $9.74 per BOE during the second quarter of 2022. The increase in per unit operating expenses compared to the same period in 2022 was due to inflation adjusted contract pricing, increased gas processing volumes due to improved capture rates, higher planned well service activity and lower natural gas production in the Marcellus. Enerplus is updating its 2023 operating expense guidance to $10.75 – $11.50 per BOE (from $10.75 – $11.75 per BOE) to reflect lower operating expenses through the first half of the year, along with higher planned workover activity and an increased liquids production weighting in the second half of the year.

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

Capital spending totaled $180.9 million in the second quarter of 2023. In addition, Enerplus paid $11.8 million in dividends in the quarter and repurchased 3.8 million shares at an average price of $14.45 per share, for total consideration of $54.8 million. During July 2023, Enerplus repurchased the remaining 0.5 million shares under its NCIB at an average price of $14.63 per share, for total consideration of $7.9 million. This was the second consecutive year of repurchasing the maximum number of shares allowed under an NCIB.

Current tax expense was $3.5 million in the second quarter. Enerplus reduced its full-year 2023 current tax expense guidance to 3 – 4% of adjusted funds flow before tax (from 5 – 6%) due to lower than forecast realized commodity prices year to date.

Enerplus ended the second quarter of 2023 with net debt of $199.6 million and a net debt to adjusted funds flow ratio of 0.2 times.

OPERATIONS

North Dakota production averaged 68,938 BOE per day during the second quarter of 2023, an increase of 18% compared to the same period a year ago and 3% higher compared to the previous quarter. During the second quarter, Enerplus drilled 17 gross operated wells (92% average working interest) and brought 23 gross operated wells (86% average working interest) on production. In addition, the Company completed 4 refracs (75% average working interest) in the quarter.

The wells brought on production in the second quarter included Enerplus' first two operated pads in the Little Knife area. Early time performance has been strong — nine of these wells have had at least 30 days on production and have averaged a gross peak 30-day rate per well of 1,900 barrels of oil per day (2,900 BOE per day on a three-stream basis).

Enerplus expects to bring approximately 14 – 17 net operated wells on production in North Dakota in the third quarter.

RETURN OF CAPITAL TO SHAREHOLDERS

During the first six months of 2023, Enerplus returned $133.1 million to shareholders through share repurchases and dividends representing 97% of free cash flow. Given the Company's strong balance sheet and the robust free cash flow profile expected during the second half of the year, Enerplus plans to return at least 60% of its second half 2023 free cash flow to shareholders, which is expected to result in over 70% of full year 2023 free cash flow returned.

Based on current market conditions, Enerplus plans to continue to prioritize share repurchases for the majority of its return of capital through 2023. In connection with this plan, the Board of Directors approved the renewal of the Company's NCIB to repurchase another 10% of the public float in the next 12-month period.

Additionally, the Board of Directors approved a 9% increase to the quarterly dividend to $0.06 per share to be paid in September 2023, for shareholders of record on August 31, 2023.

Remaining free cash flow not allocated to shareholder returns is expected to be directed to reinforcing the balance sheet.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE UPDATE

As highlighted with the release of its 2023 ESG report in June 2023, Enerplus is delivering meaningful reductions to its greenhouse gas ("GHG") emissions profile through its flaring reduction and engine and power initiatives. The Company anticipates a reduction to its 2023 scope 1 and 2 GHG emissions intensity of approximately 30% compared to 2021 (representing an approximate 50% reduction compared to 2019). Given this performance, the Company anticipates achieving its 2030 GHG emissions intensity reduction target as early as 2024 and plans to provide an updated long-term target in due course.

2023 GUIDANCE UPDATE AND THIRD QUARTER OUTLOOK

Enerplus' updated 2023 guidance is provided in the tables below.

Enerplus increased its total production guidance to 94,500 – 98,500 BOE per day, from the prior guidance of 93,000 – 98,000 BOE per day. Liquids production guidance was increased to 58,500 – 61,500 barrels per day, from the prior guidance of 57,000 – 61,000 barrels per day. The increase to production guidance reflects strong well performance in North Dakota.

The execution of the Company's capital program remains on schedule and budget. Capital spending guidance has been narrowed to $510 – $550 million, from $500 – $550 million.

Enerplus is anticipating strong oil production growth in the second half of 2023. Third quarter liquids production is expected to be approximately 10% higher than the second quarter, with an oil weighting of approximately 82%. Natural gas production is anticipated to be modestly lower in the third quarter, compared to the second quarter, due to lower production from the Marcellus.

2023 Guidance Summary

	Updated Guidance	Previous Guidance
Capital spending	$510 – 550 million	$500 - 550 million
Average total production	94,500 – 98,500 BOE/day	93,000 – 98,000 BOE/day
Average liquids production	58,500 – 61,500 bbls/day	57,000 – 61,000 bbls/day
Average production tax rate (% of net sales, before transportation)	8%	7 – 8%
Operating expense	$10.75 – 11.50/BOE	$10.75 – 11.75/BOE
Transportation expense	$4.20/BOE (No change)	$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	5 – 6% 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)	Par with WTI	+ $0.50/bbl
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.

Q2 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 Thursday, August 10, 2023, to discuss these results. Details of the conference call are as follows:

Date: Thursday, August 10, 2023
Time: 9:00 AM MT (11:00 AM ET)
Audiocast: https://app.webinar.net/A7O5L5MLQxa

To immediately join the conference call by phone, without operator assistance, please use the following URL to register and be connected into the conference call by automated call back: https://emportal.ink/3XaahvI.

To join the call from a live operator managed queue, please dial 1-888-390-0546 (Toll Free) using conference ID 32077979.

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: 077979 #

PRICE RISK MANAGEMENT

The following is a summary of Enerplus' financial commodity hedging contracts at August 8, 2023.

	WTI Crude Oil ($/bbl)(1)(2)	NYMEX Natural Gas ($/Mcf)(2)
	Jul 1, 2023 – Dec 31, 2023	**Jul 1, 2023 – Oct 31, 2023**
Swaps		
Volume (bbls/day)	10,000	–
Brent - WTI Spread	$ 5.47	–
3 Way Collars		
Volume (bbls/day)	5,000	–
Sold Puts	$ 65.00	–
Purchased Puts	$ 85.00	–
Sold Calls	$ 128.16	–
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 outstanding hedges is $1.07/bbl from July 1, 2023 - December 31, 2023.
(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.

SECOND QUARTER 2023 PRODUCTION AND OPERATIONAL SUMMARY TABLES

Summary of Average Daily Production(1)

	Three months ended June 30, 2023				Six months ended June 30, 2023			
	Williston Basin	Marcellus	Other(2)	Total	Williston Basin	Marcellus	Other(2)	Total
Tight oil (bbl/d)	46,749	—	680	47,430	46,687	—	712	47,399
Total crude oil (bbl/d)	**46,749**	**—**	**680**	**47,430**	**46,687**	**—**	**712**	**47,399**
Natural gas liquids (bbl/d)	**10,666**	**—**	**118**	**10,784**	**9,975**	**—**	**104**	**10,079**
Shale gas (Mcf/d)	69,142	154,211	797	224,149	66,849	167,126	795	234,770
Total natural gas (Mcf/d)	**69,142**	**154,211**	**797**	**224,149**	**66,849**	**167,126**	**795**	**234,770**
Total production (BOE/d)	**68,938**	**25,702**	**931**	**95,572**	**67,804**	**27,854**	**949**	**96,606**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin.

Summary of Wells Drilled(1)

	Three months ended June 30, 2023				Six months ended June 30, 2023			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	17	15.6	36	5.0	31	27.6	54	6.5
Marcellus	—	—	14	0.2	—	—	26	0.4
DJ Basin	1	1.0	—	—	3	2.9	—	—
Total	**18**	**16.6**	**50**	**5.2**	**34**	**30.5**	**80**	**6.9**

(1) Table may not add due to rounding.

Summary of Wells Brought On-Stream(1)

	Three months ended June 30, 2023				Six months ended June 30, 2023			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	23	19.8	11	3.1	27	22.8	14	3.2
Marcellus	—	—	8	0.1	—	—	21	0.3
DJ Basin	—	—	10	0.2	—	—	10	0.2
Total	**23**	**19.8**	**29**	**3.4**	**27**	**22.8**	**45**	**3.7**

(1) Table may not add due to rounding.

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.

Readers are urged 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.

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; 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, anticipated renewal of the Company's NCIB based on current market conditions, including the timing and size thereof; expectations regarding the number of net operated wells brought on production in the third quarter 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 and the timing thereof; 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; 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; our ability to achieve, in a timely manner, all necessary regulatory approvals for the renewal of the Company's NCIB; 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 0.75. 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 second 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’ second 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 June 30,		Six months ended June 30,	
($ millions)	**2023**	**2022**	**2023**	**2022**
Net income/(loss)	**$ 74.2**	**$ 244.4**	**$ 211.7**	**$ 277.6**
Unrealized derivative instrument, foreign exchange and marketable securities (gain)/loss	11.7	(94.6)	16.4	40.0
Other expense related to investing activities	—	—	—	13.1
Tax effect	(1.5)	22.5	(3.0)	(12.6)
Adjusted net income/(loss)	**$ 84.4**	**$ 172.3**	**$ 225.1**	**$ 318.1**

“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 June 30,		Six months ended June 30,	
($ millions)	**2023**	**2022**	**2023**	**2022**
Cash flow from/(used in) operating activities	$ 186.6	$ 250.9	$ 428.0	$ 446.9
Asset retirement obligation settlements	2.1	2.3	8.9	11.1
Changes in non-cash operating working capital	7.9	44.2	20.2	101.3
Adjusted funds flow	**$ 196.6**	**$ 297.4**	**$ 457.1**	**$ 559.3**
Capital spending	(180.9)	(132.9)	(319.6)	(231.9)
Free cash flow	**$ 15.7**	**$ 164.5**	**$ 137.5**	**$ 327.4**

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 August 9, 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 six months ended June 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 3% during the second quarter of 2023, compared to the first quarter of 2023, primarily due to additional completions activity in North Dakota. The increase in crude oil and natural gas liquids production was offset by a 14% decrease in natural gas production in the Marcellus as a result of limited capital investment during 2023. As a result, total production during the second quarter of 2023 averaged 95,572 BOE/day, a decrease of 2% compared to average production of 97,652 BOE/day in the first quarter of 2023. As a result of strong crude oil and natural gas liquids production volumes during the first half of the year, we are increasing our average annual crude oil and natural gas liquids production guidance for 2023 to 58,500 bbls/day - 61,500 bbls/day and average annual total production guidance to 94,500 BOE/day - 98,500 BOE/day, from 57,000 bbls/day - 61,000 bbls/day of average annual crude oil and natural gas liquids production and 93,000 BOE/day - 98,000 BOE/day of average annual total production.

During the second quarter of 2023, a total of $66.5 million was returned to shareholders through share repurchases and dividends, consistent with $66.6 million in the first quarter of 2023, representing 97% of free cash flow[1] in the first half of 2023. Given the Company's strong balance sheet and robust free cash flow profile expected during the second half of the year, we plan to return at least 60% of second half 2023 free cash flow[1] to shareholders, which is expected to result in over 70% of full year 2023 free cash flow[1] returned.

Based on current market conditions, the Company expects to continue to prioritize share repurchases for the majority of its return of capital plan. In connection with this plan, the Company completed its Normal Course Issuer Bid ("NCIB") in July 2023, and fully repurchased 10% of its public float (within the meaning under Toronto Stock Exchange ("TSX") rules) within the last 12 months for the second consecutive year. Subsequent to the quarter, the Board of Directors approved the renewal of the Company's NCIB to purchase another 10% of the public float in the next 12-month period.

The Board of Directors also approved a 9% increase to the quarterly dividend to $0.060 per share, from $0.055 per share, beginning September 2023. We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

Capital spending during the second quarter of 2023 was $180.9 million, compared to $138.6 million during the first quarter of 2023, with the majority of the spending focused on our U.S. crude oil properties. The increase in capital spending was due to increased completions activity on our North Dakota properties. We are narrowing our annual capital spending guidance for 2023 to range between $510 - $550 million from $500 - $550 million.

Our realized Bakken crude oil price differential averaged $0.71/bbl below WTI during the second quarter of 2023, compared to $0.06/bbl above WTI during the first quarter of 2023. The weaker realized differential was due to lower prices for crude oil delivered to markets in both North Dakota and the U.S. Gulf Coast primarily due to weaker U.S. refinery margins early in the quarter. U.S. refinery utilization recovered later in the second quarter supported by resilient domestic product demand. We are revising our expected annual realized Bakken crude oil price differential to be at par with WTI, from a crude oil price differential of $0.50/bbl above WTI, previously.

Our realized Marcellus sales price differential averaged $0.68/Mcf below NYMEX in the second quarter of 2023 compared to $0.64/Mcf below NYMEX in the first quarter of 2023. The slightly wider differential was mainly due to lower seasonal demand in the spring months compared to the winter. We continue to expect our annual realized Marcellus differential to average $0.75/Mcf below NYMEX in 2023.

Operating expenses for the second quarter of 2023 decreased to $89.1 million, or $10.25/BOE, compared to $92.8 million, or $10.56/BOE during the first quarter of 2023. The decrease was due to fewer weather related expenses in the second quarter of 2023 when compared to the previous period. As a result of lower operating expenses during the first half of the year, higher planned workover activity and an increased crude oil and natural gas liquids weighting in the second half of the year, we are revising our operating expenses guidance for 2023 to range between $10.75/BOE - $11.50/BOE from $10.75/BOE - $11.75/BOE.

We reported net income of $74.2 million in the second quarter of 2023, compared to net income of $137.5 million in the first quarter of 2023. Net income decreased primarily due to lower commodity prices and commodity derivative instrument gains in the second quarter of 2023.

In the second quarter of 2023, cash flow from operating activities and adjusted funds flow decreased to $186.6 million and $196.6 million, respectively, compared to $241.4 million and $260.4 million in the first quarter of 2023. The decrease was primarily due to lower commodity prices and realized commodity derivative instrument gains, offset by lower cash taxes, in the second quarter of 2023.

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

At June 30, 2023, net debt increased to $199.6 million, compared to $150.6 million at March 31, 2023 due to the acceleration of our share repurchases during the second quarter of 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 $37.5 million. At June 30, 2023, a total of $93.5 million was drawn on our Bank Credit Facilities. Our net debt to adjusted funds flow ratio increased to 0.2x from 0.1x in the first quarter of 2023.

RESULTS OF OPERATIONS

Production

Crude oil and natural gas liquids production increased by 3% during the second quarter of 2023, compared to the first quarter of 2023, primarily due to additional completions activity in North Dakota with 19.8 net operated wells and 3.1 net non-operated wells coming on-stream. The increase in crude oil and natural gas liquids production was offset by a 14% decrease in natural gas production in the Marcellus as a result of limited capital investment during 2023. As a result, total production during the second quarter of 2023 averaged 95,572 BOE/day, a decrease of 2% compared to average production of 97,652 BOE/day in the first quarter of 2023.

The increase in production for the three and six months ended June 30, 2023, compared to the same period in 2022, was partially due to strong well performance on 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, offset by the sale of substantially all of our Canadian assets in the fourth quarter of 2022.

Our crude oil and natural gas liquids weighting increased to 61% from 60% for the three months ended June 30, 2023 and decreased to 59% from 61% for the six months ended June 30, 2023, compared to the same periods in 2022.

As a result of strong crude oil and natural gas liquids production volumes during the first half of the year, we are increasing our average annual crude oil and natural gas liquids production guidance for 2023 to 58,500 bbls/day - 61,500 bbls/day, and average annual total production guidance to 94,500 BOE/day - 98,500 BOE/day, from 57,000 bbls/day - 61,000 bbls/day of average annual crude oil and natural gas liquids production, and 93,000 BOE/day - 98,000 BOE/day of average annual total production.

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

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2023**	**2022**	**% Change**	**2023**	**2022**	**% Change**
Light and medium oil (bbls/day)	—	2,082	(100%)	—	2,127	(100%)
Heavy oil (bbls/day)	—	2,886	(100%)	—	2,959	(100%)
Tight oil (bbls/day)	47,430	43,245	10%	47,399	42,839	11%
Total crude oil (bbls/day)	47,430	48,213	(2%)	47,399	47,925	(1%)
Natural gas liquids (bbls/day)	10,784	8,653	25%	10,079	8,516	18%
Conventional natural gas (Mcf/day)	—	7,319	(100%)	—	7,256	(100%)
Shale gas - Marcellus (Mcf/day)	154,211	167,631	(8%)	167,126	164,900	1%
Shale gas - Bakken (Mcf/day)	69,938	48,703	44%	67,644	48,244	40%
Total natural gas (Mcf/day)	224,149	223,653	0%	234,770	220,400	7%
Total daily sales (BOE/day)	95,572	94,142	2%	96,606	93,174	4%

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:

Pricing (average for the period)	**Six months ended June 30, 2023**	**Six months ended June 30, 2022**	**Q2 2023**	**Q1 2023**	**Q4 2022**	**Q3 2022**	**Q2 2022**
Benchmarks							
WTI crude oil ($/bbl)	$ 74.96	$ 101.35	$ 73.78	$ 76.13	$ 82.65	$ 91.56	$ 108.41
Brent (ICE) crude oil ($/bbl)	80.12	104.58	78.01	82.22	88.60	97.81	111.78
Propane – Conway ($/bbl)	30.34	52.59	27.70	32.99	34.21	44.73	51.16
NYMEX natural gas – last day ($/Mcf)	2.76	6.06	2.10	3.42	6.26	8.20	7.17
CDN/US average exchange rate	0.74	0.79	0.74	0.74	0.74	0.77	0.78
CDN/US period end exchange rate	0.76	0.78	0.76	0.74	0.74	0.72	0.78
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 74.50	$ 100.46	$ 72.69	$ 76.34	$ 83.06	$ 92.48	$ 108.77
Natural gas liquids ($/bbl)	17.83	35.49	15.49	20.55	21.88	32.04	33.31
Natural gas ($/Mcf)	2.17	5.38	1.08	3.18	4.76	6.53	6.11
Average differentials							
Bakken DAPL – WTI ($/bbl)	$ 1.05	$ 1.85	$ 0.78	$ 1.32	$ 3.19	$ 3.60	$ 2.99
Brent (ICE) – WTI ($/bbl)	5.16	3.23	4.23	6.09	5.95	6.25	3.37
Transco Leidy monthly – NYMEX ($/Mcf)	(0.59)	(0.80)	(0.63)	(0.54)	(1.51)	(1.06)	(0.90)
Transco Z6 Non-New York monthly – NYMEX ($/Mcf)	1.39	0.28	(0.57)	3.35	(0.20)	(0.85)	(0.87)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI ($/bbl)	$ (0.33)	$ 0.23	$ (0.71)	$ 0.06	$ 1.05	$ 2.41	$ 0.85
Marcellus natural gas – NYMEX ($/Mcf)	(0.65)	(0.30)	(0.68)	(0.64)	(1.18)	(0.99)	(0.59)

(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 second quarter of 2023, our realized crude oil sales price averaged $72.69/bbl, a decrease of 5% compared to the first quarter of 2023, in line with the decreases in the underlying benchmark WTI price and Bakken differentials over the same period. WTI prices declined through the quarter despite additional production cuts from the OPEC+ group of producers which were outweighed by demand-related concerns resulting from rising interest rates, global recession risk and a slower than expected economic recovery in China.

Our realized Bakken crude oil price differential averaged $0.71/bbl below WTI during the second quarter of 2023, compared to $0.06/bbl above WTI during the first quarter of 2023. The weaker realized differential was due to lower prices for crude oil delivered to markets in both North Dakota and the U.S. Gulf Coast primarily due to weaker U.S. refinery margins early in the quarter. U.S. refinery utilization recovered later in the second quarter supported by resilient domestic product demand. We are revising our expected annual realized Bakken crude oil price differential to be at par with WTI, from a crude oil price differential of $0.50/bbl above WTI, previously.

NATURAL GAS LIQUIDS

Our realized sales price for natural gas liquids averaged $15.49/bbl during the second quarter of 2023 compared to $20.55/bbl during the first quarter of 2023. As a percentage of WTI, our realized natural gas liquids price decreased proportionately to the decrease in the Conway propane benchmark in the second quarter of 2023, compared to the first quarter of 2023. Our natural gas liquids are predominantly comprised of propane, and propane pricing weakened considerably during the second quarter due to strong U.S. domestic production growth, resulting in U.S. propane inventories accumulating well above the five-year range.

NATURAL GAS

Our realized natural gas sales price averaged $1.08/Mcf during the second quarter of 2023, a decrease of 66% compared to the first quarter of 2023. The NYMEX benchmark price decreased by 39% over the same period. The difference in price realization versus the benchmark was due to weaker regional prices received for our Bakken natural gas production.

Our realized Marcellus sales price differential averaged $0.68/Mcf below NYMEX in the second quarter of 2023 compared to $0.64/Mcf below NYMEX in the first quarter of 2023. The slightly wider differential was mainly due to lower seasonal demand in the spring months compared to the winter. We continue to expect our annual realized Marcellus differential to average $0.75/Mcf below NYMEX.

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 August 8, 2023, we have hedged 5,000 bbls/day of WTI exposure for the second half of 2023. We have also hedged 50,000 Mcf/day of NYMEX exposure for the period from July 1, 2023 to October 31, 2023. 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 is a summary of our financial contracts in place at August 8, 2023:

	WTI Crude Oil ($/bbl)(1)(2)	**NYMEX Natural Gas ($/Mcf)(2)**
	Jul 1, 2023 – Dec 31, 2023	**Jul 1, 2023 – Oct 31, 2023**
Swaps		
Volume (bbls/day)	10,000	–
Brent - WTI Spread	$ 5.47	–
3 Way Collars		
Volume (bbls/day)	5,000	–
Sold Puts	$ 65.00	–
Purchased Puts	$ 85.00	–
Sold Calls	$ 128.16	–
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 $1.07/bbl from July 1, 2023 – December 31, 2023.
(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 June 30,**		**Six months ended June 30,**	
($ millions)	**2023**	**2022**	**2023**	**2022**
Realized gains/(losses):				
Crude oil	$ 5.3	$ (109.9)	$ 8.7	$ (182.6)
Natural gas	8.9	(28.3)	39.8	(28.7)
Total realized gains/(losses)	$ 14.2	$ (138.2)	$ 48.5	$ (211.3)
Unrealized gains/(losses):				
Crude oil	$ 1.5	$ 68.5	$ 5.2	$ (27.2)
Natural gas	(8.7)	22.1	(18.8)	(15.9)
Total unrealized gains/(losses)	$ (7.2)	$ 90.6	$ (13.6)	$ (43.1)
Total commodity derivative instruments gains/(losses)	$ 7.0	$ (47.6)	$ 34.9	$ (254.4)

	Three months ended June 30,		**Six months ended June 30,**	
(Per BOE)	**2023**	**2022**	**2023**	**2022**
Total realized gains/(losses)	$ 1.63	$ (16.13)	$ 2.77	$ (12.53)
Total unrealized gains/(losses)	(0.83)	10.58	(0.78)	(2.56)
Total commodity derivative instruments gains/(losses)	$ 0.80	$ (5.55)	$ 1.99	$ (15.09)

During the three and six months ended June 30, 2023, Enerplus realized gains of $5.3 million and $8.7 million, respectively, on our crude oil contracts, compared to realized losses of $109.9 million and $182.6 million for the same periods in 2022. For the three and six months ended June 30, 2023, realized gains of $8.9 million and $39.8 million, respectively, were recorded on our natural gas contracts, compared to realized losses of $28.3 million and $28.7 million for the same periods in 2022. Realized gains recorded during the three and six months ended June 30, 2023 were due to 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 June 30, 2023, the fair value of our crude oil and natural gas contracts was in a net asset position of $14.0 million (December 31, 2022 – net asset position of $26.1 million). For the three and six months ended June 30, 2023, the change in the fair value of our crude oil contracts resulted in unrealized gains of $1.5 million and $5.2 million, respectively, compared to an unrealized gain of $68.5 million and an unrealized loss of $27.2 million during the same periods in 2022. For the three and six months ended June 30, 2023, we recorded unrealized losses on our natural gas contracts of $8.7 million and $18.8 million, respectively, compared to an unrealized gain of $22.1 million and an unrealized loss of $15.9 million during the same periods in 2022.

Crude Oil and Natural Gas Sales

	Three months ended June 30,		**Six months ended June 30,**	
($ millions, except per BOE amounts)	**2023**	**2022**	**2023**	**2022**
Crude oil and natural gas sales	$ 350.9	$ 628.0	$ 764.1	$ 1,141.2
Per BOE	$ 40.35	$ 73.31	$ 43.70	$ 67.67

Crude oil and natural gas sales for the three and six months ended June 30, 2023 were $350.9 million, or $40.35/BOE, and $764.1 million, or $43.70/BOE, respectively, compared to $628.0 million, or $73.31/BOE, and $1,141.2 million, or $67.67/BOE, for the same periods in 2022. The decrease in revenue was primarily due to significantly lower commodity prices in the first half of 2023, lower natural gas production in the Marcellus in the second quarter of 2023, and the impact of the Canadian divestments completed in the fourth quarter of 2022.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Operating expenses	$ 89.1	$ 83.4	$ 181.9	$ 166.6
Per BOE	$ 10.25	$ 9.74	$ 10.40	$ 9.88

For three and six months ended June 30, 2023, operating expenses were $89.1 million, or $10.25/BOE, and $181.9 million, or $10.40/BOE, respectively, compared to $83.4 million, or $9.74/BOE, and $166.6 million, or $9.88/BOE, for the same periods in 2022. The increase was due to inflation adjusted contract pricing, increased gas processing volumes due to improved capture rates, and higher planned well service activity. The per BOE increase was also due to lower natural gas production in the Marcellus which has lower associated operating expenses.

We are updating our 2023 operating expense guidance to $10.75 - $11.50/BOE (from $10.75 - $11.75/BOE) to reflect lower operating expenses through the first half of the year, along with higher planned workover activity and an increased crude oil and natural gas liquids production weighting in the second half of the year.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Transportation costs	$ 34.4	$ 37.8	$ 72.2	$ 73.6
Per BOE	$ 3.96	$ 4.41	$ 4.13	$ 4.36

For three and six months ended June 30, 2023, transportation costs were $34.4 million, or $3.96/BOE, and $72.2 million, or $4.13/BOE, respectively, compared to $37.8 million, or $4.41/BOE, and $73.6 million, or $4.36/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.

We are maintaining our transportation costs of $4.20/BOE in 2023.

Production Taxes

($ millions, except per BOE amounts)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Production taxes	$ 28.8	$ 43.8	$ 58.9	$ 79.2
Per BOE	$ 3.31	$ 5.11	$ 3.37	$ 4.70
Production taxes (% of crude oil and natural gas sales)	8.2%	7.0%	7.7%	6.9%

Production taxes for three and six months ended June 30, 2023, were $28.8 million, or 8.2%, and $58.9 million, or 7.7%, respectively, compared to $43.8 million, or 7.0%, and $79.2 million, or 6.9% for the same periods in 2022. The decrease in total production taxes was due to lower realized prices and the effect of the Canadian divestments in the fourth quarter of 2022, partially offset by increased U.S. crude oil production which has higher rates of production tax.

We are revising our production taxes guidance for 2023 to average 8% from a range between 7% - 8%.

Netbacks

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

	Three months ended June 30, 2023		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	69,846 BOE/day	154,353 Mcfe/day	95,572 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 52.10	$ 1.41	$ 40.35
Operating expenses	(13.56)	(0.21)	(10.25)
Transportation costs	(3.40)	(0.91)	(3.96)
Production taxes	(4.46)	(0.03)	(3.31)
Netback before impact of commodity derivative contracts	$ 30.68	$ 0.26	$ 22.83
Realized gains/(losses) on commodity derivative contracts	0.84	0.63	1.63
Netback after impact of commodity derivative contracts	$ 31.52	$ 0.89	$ 24.46
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 195.0	$ 3.7	$ 198.6
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 200.3	$ 12.6	$ 212.8

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

	Three months ended June 30, 2022		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	65,070 BOE/day	174,433 Mcfe/day	94,142 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 88.37	$ 6.60	$ 73.31
Operating expenses	(13.51)	(0.22)	(9.74)
Transportation costs	(3.97)	(0.90)	(4.41)
Production taxes	(7.25)	(0.06)	(5.11)
Netback before impact of commodity derivative contracts	$ 63.64	$ 5.42	$ 54.05
Realized gains/(losses) on commodity derivative contracts	(18.56)	(1.78)	(16.13)
Netback after impact of commodity derivative contracts	$ 45.08	$ 3.64	$ 37.92
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 376.9	$ 86.1	$ 463.0
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 267.0	$ 57.8	$ 324.8

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

	Six months ended June 30, 2023		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	68,706 BOE/day	167,404 Mcfe/day	96,606 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 56.17	$ 2.17	$ 43.70
Operating expenses	(14.19)	(0.18)	(10.40)
Transportation costs	(3.64)	(0.89)	(4.13)
Production taxes	(4.67)	(0.03)	(3.37)
Netback before impact of commodity derivative contracts	$ 33.67	$ 1.07	$ 25.80
Realized gains/(losses) on commodity derivative contracts	0.70	1.31	2.77
Netback after impact of commodity derivative contracts	$ 34.37	$ 2.38	$ 28.57
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 418.7	$ 32.4	$ 451.0
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 427.4	$ 72.3	$ 499.6

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

Netbacks by Property Type	Six months ended June 30, 2022 Crude Oil	Natural Gas	Total
Average Daily Production	64,556 BOE/day	171,711 Mcfe/day	93,174 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 82.29	$ 5.78	$ 67.67
Operating expenses	(13.64)	(0.23)	(9.88)
Transportation costs	(3.92)	(0.90)	(4.36)
Production taxes	(6.64)	(0.05)	(4.70)
Netback before impact of commodity derivative contracts	$ 58.09	$ 4.60	$ 48.73
Realized gains/(losses) on commodity derivative contracts	(15.62)	(0.92)	(12.53)
Netback after impact of commodity derivative contracts	$ 42.47	$ 3.68	$ 36.20
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 679.0	$ 142.8	$ 821.8
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 496.4	$ 114.1	$ 610.5

(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 six months ended June 30, 2023 were lower compared to the same periods in 2022, primarily due to lower realized prices.

For the three and six months ended June 30, 2023, crude oil properties accounted for 98% and 93%, respectively, of total netback before commodity derivative contracts, compared to 81% and 83% 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 June 30, 2023	2022	Six months ended June 30, 2023	2022
Cash:				
G&A expenses	$ 10.4	$ 9.4	$ 23.4	$ 20.6
Share-based compensation expense/(recovery)	0.1	0.3	(0.9)	2.4
Non-Cash:				
Share-based compensation expense/(recovery)	4.7	5.7	12.2	10.5
Equity swap gain	—	(0.6)	—	(1.0)
G&A recovery	(0.1)	(0.1)	(0.2)	(0.2)
Total G&A expenses	$ 15.1	$ 14.7	$ 34.5	$ 32.3

(Per BOE)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Cash:				
G&A expenses	$ 1.20	$ 1.10	$ 1.34	$ 1.22
Share-based compensation expense/(recovery)	0.01	0.04	(0.05)	0.14
Non-Cash:				
Share-based compensation expense/(recovery)	0.54	0.67	0.70	0.62
Equity swap gain	—	(0.07)	—	(0.06)
G&A recovery	(0.01)	(0.01)	(0.01)	(0.01)
Total G&A expenses	$ 1.74	$ 1.73	$ 1.98	$ 1.92

Cash G&A expenses for three and six months ended June 30, 2023 were $10.4 million, or $1.20/BOE, and $23.4 million, or $1.34/BOE, respectively, compared to $9.4 million, or $1.10/BOE, and $20.6 million or $1.22/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 six months ended June 30, 2023, was an expense of $0.1 million, or $0.01/BOE, and a recovery of $0.9 million, or $0.05/BOE, respectively, compared to expenses of $0.3 million, or $0.04/BOE, and $2.4 million, or $0.14/BOE, for the same periods in 2022, and relates to our director plans. The recovery was due to a decrease in Enerplus' share price in 2023 compared to an increase in share price in the same period in 2022.

Equity-settled non-cash SBC for the three and six months ended June 30, 2023, was $4.7 million or $0.54/BOE, and $12.2 million or $0.70/BOE, respectively, compared to $5.7 million, or $0.67/BOE, and $10.5 million, or $0.62/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 June 30, 2023, the decrease was due to the applicable multipliers being lower, partially offset by the full accelerated expense on retirement eligible awards, compared to the same period in 2022. For the six months ended June 30, 2023, the increase was due to additional expense on the acceleration of newly retirement eligible awards partially offset by a decrease in the applicable multipliers, compared to the same period in 2022.

Enerplus previously had hedged a portion of the outstanding cash-settled units under our LTI plans. During the three and six months ended June 30, 2022, we recorded a mark-to-market gain of $0.6 million and $1.0 million, as a result of the higher share prices. Enerplus settled its equity derivative contracts during 2022 and did not have any equity derivatives outstanding at June 30, 2023.

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

Interest Expense

For the three and six months ended June 30, 2023, we recorded a total interest expense of $3.6 million and $7.9 million, respectively, compared to $6.1 million and $12.2 million for the same periods in 2022. The decrease was primarily due to lower debt levels in the first half of 2023, compared to the first half of 2022, as free cash flow throughout 2022 was used to repay debt.

At June 30, 2023, $93.5 million was drawn on the Bank Credit Facilities. At June 30, 2023, approximately 61% of our debt was based on fixed interest rates and 39% on floating interest rates (December 31, 2022 – 78%, 22%), with a weighted average interest rate of 4.0% and 6.4%, respectively (December 31, 2022 – 4.1%, 5.7%).

Foreign Exchange

($ millions)	Three months ended June 30, 2023	Three months ended June 30, 2022	Six months ended June 30, 2023	Six months ended June 30, 2022
Realized:				
Foreign exchange (gain)/loss	$ (0.3)	$ 0.2	$ (0.2)	$ (0.1)
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company	—	(0.1)	—	(0.1)
Unrealized:				
Foreign exchange (gain)/loss on Canadian dollar working capital in parent company	(0.5)	—	(0.7)	—
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company	—	(3.3)	—	(2.1)
Total foreign exchange (gain)/loss	$ (0.8)	$ (3.2)	$ (0.9)	$ (2.3)
CDN/US average exchange rate	0.74	0.78	0.74	0.79
CDN/US period end exchange rate	0.76	0.78	0.76	0.78

For three and six months ended June 30, 2023, Enerplus recorded foreign exchange gains of $0.8 million and $0.9 million, respectively, compared to gains of $3.2 million and $2.3 million for the same periods in 2022.

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 six months ended June 30, 2023, there were no unrealized foreign exchange gains or losses recorded in Other Comprehensive Income/(Loss) compared to unrealized losses of $14.1 million and $8.7 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")

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2023	2022	2023	2022
Capital spending[1]	$ 180.9	$ 132.9	$ 319.6	$ 231.9
Office capital	1.5	0.1	1.3	0.4
Sub-total	182.4	133.0	320.9	232.3
Property and land acquisitions	1.6	1.5	3.4	3.4
Property and land divestments[1]	0.1	(8.6)	(0.2)	(15.2)
Sub-total	1.7	(7.1)	3.2	(11.8)
Total	$ 184.1	$ 125.9	$ 324.1	$ 220.5

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

Capital spending for the three and six months ended June 30, 2023 totaled $180.9 million and $319.6 million, respectively, compared to $132.9 million and $231.9 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 in 2023.

Property and land divestments for the three and six months ended June 30, 2023, were $0.1 million and $0.2 million, respectively, compared to $8.6 million and $15.2 million for the same periods in 2022. Property and land divestments for the six months ended June 30, 2022 relate to the sale of minor non-operated interests in North Dakota and Colorado.

We are narrowing our capital spending for 2023 to range between $510 - $550 million from $500 - $550 million.

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

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2023	2022	2023	2022
DD&A expense	$ 85.1	$ 70.1	$ 172.2	$ 136.8
Per BOE	$ 9.79	$ 8.18	$ 9.85	$ 8.11

DD&A related to PP&E is recognized using the unit of production method based on proved reserves. For the three and six months ended June 30, 2023, Enerplus recorded DD&A expense of $85.1 million, or $9.79/BOE, and $172.2 million, or $9.85/BOE, respectively, compared to $70.1 million, or $8.18/BOE, and $136.8 million, or $8.11/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 $119.1 million at June 30, 2023, compared to $114.7 million at December 31, 2022.

For the three and six months ended June 30, 2023, ARO settlements were $2.1 million and $8.9 million, respectively, compared to $2.3 million and $11.1 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 is reflected as a reduction to ARO. During the three and six months ended June 30, 2022, Enerplus benefited from $0.1 million and $0.5 million, respectively, in government assistance.

Income Taxes

($ millions)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Current tax expense	$ 3.5	$ 12.0	$ 14.5	$ 17.0
Deferred tax expense	21.1	71.7	45.0	81.5
Total tax expense	$ 24.6	$ 83.7	$ 59.5	$ 98.5

For the three and six months ended June 30, 2023, we recorded a current tax expense of $3.5 million and $14.5 million, respectively, compared to $12.0 million and $17.0 million for the same periods in 2022. Current tax expense in 2023 was lower compared to 2022 primarily due to lower income. Many factors influence taxable income, including future commodity prices, production levels, development activities, capital spending, and overall profitability. We are revising our cash tax guidance for 2023 to 3.0% - 4.0% from 5.0% - 6.0% of adjusted funds flow before tax based on guidance pricing.

For the three and six months ended June 30, 2023, we recorded a deferred income tax expense of $21.1 million and $45.0 million, respectively, compared to an expense of $71.7 million and $81.5 million for the same periods in 2022. Deferred tax expense was lower in 2023 compared to 2022 due to lower 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 six months ended June 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 $143.9 million, offset by a deferred income tax liability in the U.S. of $89.3 million as at June 30, 2023. (December 31, 2022 - $155.0 million deferred income tax asset in Canada offset by $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 six months, after which it drops to 3.0x. At June 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 June 30, 2023 decreased to $199.6 million, compared to $221.5 million at December 31, 2022. Net debt was comprised of our senior notes and Bank Credit Facilities totaling $237.1 million, less cash on hand of $37.5 million.

At June 30, 2023, through our Bank Credit Facilities, we had total credit capacity of $1.3 billion, of which $93.5 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 92% and 70% for the three and six months ended June 30, 2023, respectively, compared to 45% and 41% for the same periods in 2022.

During the six months ended June 30, 2023, a total of $133.1 million was returned to shareholders through share repurchases and dividends, compared to $147.9 million for the same period in 2022. During the six months ended June 30, 2023, a total of 7.3 million common shares were repurchased and cancelled under the NCIB at an average price of $14.89 per share, for total consideration of $109.3 million. During the six months ended June 30, 2022, a total of 10.2 million common shares were repurchased and cancelled under the NCIB at an average price of $12.74 per share, for total consideration of $130.1 million.

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

Subsequent to June 30, 2023, we repurchased 0.5 million common shares under the NCIB at an average price of $14.63 per share, for total consideration of $7.9 million. The Company completed its NCIB in July 2023, and fully repurchased 10% of its public float (within the meaning under TSX rules) within the last 12 months for the second consecutive year. Subsequent to the quarter, the Board of Directors approved the renewal of the Company's NCIB to purchase another 10% of the public float in the next 12-month period.

Given the Company's strong balance sheet and robust free cash flow profile expected during the second half of the year, we plan to return at least 60% of second half 2023 free cash flow[1] to shareholders through share repurchases and dividends, which is expected to result in over 70% of full year 2023 free cash flow[1] returned. 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. In connection with this plan, the Board of Directors has approved a 9% increase to the quarterly dividend to $0.060 per share, from $0.055 per share, beginning September 2023. We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

At June 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.com.

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

Covenant Description		June 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%	5%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	63.5x

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 June 30, 2023 was $203.7 million and $1,290.3 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 June 30,		Six months ended June 30,	
($ millions, except per share amounts)	2023	2022	2023	2022
Dividends	$ 11.8	$ 9.9	$ 23.7	$ 17.8
Per weighted average share (Basic)	$ 0.055	$ 0.043	$ 0.110	$ 0.076

During the three and six months ended June 30, 2023, we declared total dividends of $11.8 million, or $0.055 per share, and $23.7 million, or $0.110 per share, respectively, compared to $9.9 million, or $0.043 per share, and $17.8 million, or $0.076 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 June 30, 2023, the Board of Directors approved a 9% increase to the quarterly dividend to $0.060 per share, from $0.055 per share, beginning September 2023. We expect to fund the dividend through the free cash flow generated by the business.

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

Shareholders' Capital

	Six months ended June 30, 2023	2022
Share capital ($ millions)	$ 2,776.1	$ 3,001.6
Common shares outstanding (thousands)	211,251	234,879
Weighted average shares outstanding – basic (thousands)	215,289	241,022
Weighted average shares outstanding – diluted (thousands)	221,276	248,957

For the six months ended June 30, 2023, a total of 2.3 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 $16.4 million (2022 – $11.6 million).

During the six months ended June 30, 2023, 7.3 million common shares were repurchased and cancelled under the NCIB at an average price of $14.89 per share, for total consideration of $109.3 million. Of the amount paid, $68.5 million was charged to share capital and $40.8 million was added to accumulated deficit. At June 30, 2023, 0.5 million common shares remained available for repurchase under the current NCIB. Subsequent to June 30, 2023, we completed our current NCIB and repurchased 0.5 million common shares at an average price of $14.63 per share, for total consideration of $7.9 million.

During the six months ended June 30, 2022, 10.2 million common shares were repurchased and cancelled under the NCIB at an average price of $12.74 per share, for total consideration of $130.1 million. Of the amount paid, $100.4 million was charged to share capital and $29.7 million was added to accumulated deficit.

Subsequent to June 30, 2023, Enerplus received approval from the Board of Directors to renew its NCIB to purchase another 10% of the public float during the following 12-month period. The NCIB renewal remains subject to approval by the TSX.

Subsequent to the quarter, 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.

At August 8, 2023, we had 210,709,740 common shares outstanding. In addition, an aggregate of 7,967,421 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	Diluted
2023				
Second Quarter	$ 350.9	$ 74.2	$ 0.35	$ 0.34
First Quarter	413.2	137.5	0.63	0.62
Total 2023	$ 764.1	$ 211.7	$ 0.98	$ 0.96
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 decreased to $350.9 million during the second quarter of 2023, compared to $413.2 million during the first quarter of 2023. We reported net income of $74.2 million during the second quarter of 2023 compared to net income of $137.5 million during the first quarter of 2023. The decrease in crude oil and natural gas sales and net income was primarily due to lower commodity prices and commodity derivative instrument gains in the second 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.

U.S Filing Status

Pursuant to U.S. securities regulations, we are required to reassess our U.S. securities filing status annually at June 30. At June 30, 2023, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

2023 GUIDANCE(1)

Summary of 2023 Annual Expectations	Target
Capital spending ($ millions)	$510 - $550 (from $500 - $550)
Average annual production (BOE/day)	94,500 - 98,500 (from 93,000 - 98,000)
Average annual crude oil and natural gas liquids production (bbls/day)	58,500 - 61,500 (from 57,000 - 61,000)
Average production tax rate (% of gross sales, before transportation)	8% (from 7 - 8%)
Operating expenses (per BOE)	$10.75 - $11.50 (from $10.75 - $11.75)
Transportation costs (per BOE)	$4.20
Cash G&A expenses (per BOE)	$1.35
Current tax expense (% of adjusted funds flow before tax)	3% - 4% (from 5% - 6%)

Differential/Basis Outlook(2)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	$0.00/bbl (from $0.50/bbl)
Average Marcellus natural gas differential (compared to last day NYMEX natural gas)	($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 June 30,		Six months ended June 30,	
($ millions)	2023	2022	2023	2022
Net income/(loss)	**$ 74.2**	**$ 244.4**	**$ 211.7**	**$ 277.6**
Unrealized derivative instrument, foreign exchange and marketable securities (gain)/loss	11.7	(94.6)	16.4	40.0
Other expense related to investing activities	—	—	—	13.1
Tax effect	(1.5)	22.5	(3.0)	(12.6)
Adjusted net income/(loss)	**$ 84.4**	**$ 172.3**	**$ 225.1**	**$ 318.1**

"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 June 30,		Six months ended June 30,	
($ millions)	2023	2022	2023	2022
Cash flow from/(used in) operating activities	$ 186.6	$ 250.9	$ 428.0	$ 446.9
Asset retirement obligation settlements	2.1	2.3	8.9	11.1
Changes in non-cash operating working capital	7.9	44.2	20.2	101.3
Adjusted funds flow	**$ 196.6**	**$ 297.4**	**$ 457.1**	**$ 559.3**
Capital spending	(180.9)	(132.9)	(319.6)	(231.9)
Free cash flow	**$ 15.7**	**$ 164.5**	**$ 137.5**	**$ 327.4**

"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 June 30,		Six months ended June 30,	
($ millions)	2023	2022	2023	2022
Crude oil and natural gas sales	$ 350.9	$ 628.0	$ 764.1	$ 1,141.2
Less:				
Operating expenses	(89.1)	(83.4)	(181.9)	(166.6)
Transportation expenses	(34.4)	(37.8)	(72.2)	(73.6)
Production taxes	(28.8)	(43.8)	(58.9)	(79.2)
Netback before impact of commodity derivative contracts	**$ 198.6**	**$ 463.0**	**$ 451.1**	**$ 821.8**
Net realized gain/(loss) on derivative instruments	14.2	(138.2)	48.5	(211.3)
Netback after impact of commodity derivative contracts	**$ 212.8**	**$ 324.8**	**$ 499.6**	**$ 610.5**

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 June 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.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and statements (“forward-looking information”) within the meaning of applicable securities laws. The use of any of the words “expect”, “anticipate”, “continue”, “estimate”, “guidance”, “ongoing”, “may”, “will”, “project”, “plans”, “budget”, “strategy” and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: 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, the anticipated renewal of the Company’s NCIB and timing 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; 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 $0.75. 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.com*,* www.sec.gov *and through Enerplus' website at* www.enerplus.com*.*

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

Condensed Consolidated Balance Sheets

(US$ thousands) unaudited	Note	June 30, 2023	December 31, 2022
Assets			
Current assets			
Cash and cash equivalents		$ 37,475	$ 38,000
Accounts receivable, net of allowance for doubtful accounts	12	239,867	276,590
Other current assets	4	56,360	56,552
Derivative financial assets	12	16,163	36,542
		349,865	407,684
Property, plant and equipment:			
Crude oil and natural gas properties (full cost method)	3	1,487,322	1,322,904
Other capital assets	3	9,837	10,685
Property, plant and equipment		1,497,159	1,333,589
Other long-term assets	4	10,561	21,154
Right-of-use assets		25,042	20,556
Deferred income tax asset	10	143,896	154,998
Total Assets		$ 2,026,523	$ 1,937,981
Liabilities			
Current liabilities			
Accounts payable		$ 400,691	$ 398,482
Current portion of long-term debt	5	80,600	80,600
Derivative financial liabilities	12	2,195	10,421
Current portion of lease liabilities		12,397	13,664
		495,883	503,167
Long-term debt	5	156,505	178,916
Asset retirement obligation	6	119,050	114,662
Lease liabilities		14,808	9,262
Deferred income tax liability	10	89,264	55,361
Total Liabilities		875,510	861,368
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: June 30, 2023 – 211 million shares			
December 31, 2022 – 217 million shares	11	2,776,088	2,837,329
Paid-in capital		38,963	50,457
Accumulated deficit		(1,362,697)	(1,509,832)
Accumulated other comprehensive loss		(301,341)	(301,341)
		1,151,013	1,076,613
Total Liabilities & Shareholders' Equity		$ 2,026,523	$ 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 June 30, 2023	Three months ended June 30, 2022	Six months ended June 30, 2023	Six months ended June 30, 2022
Revenues					
Crude oil and natural gas sales	7	$ 350,939	$ 628,017	$ 764,121	$ 1,141,169
Commodity derivative instruments gain/(loss)	12	6,961	(47,553)	34,926	(254,363)
		357,900	580,464	799,047	886,806
Expenses					
Operating		89,116	83,366	181,920	166,610
Transportation		34,433	37,830	72,201	73,637
Production taxes		28,765	43,827	58,888	79,182
General and administrative	8	15,074	14,687	34,506	32,268
Depletion, depreciation and accretion		85,117	70,090	172,226	136,781
Interest		3,592	6,098	7,910	12,153
Foreign exchange (gain)/loss	9	(794)	(3,232)	(891)	(2,345)
Other expense/(income)	4, 6	3,728	(309)	1,062	12,388
		259,031	252,357	527,822	510,674
Income/(Loss) Before Taxes		98,869	328,107	271,225	376,132
Current income tax expense/(recovery)	10	3,500	12,000	14,500	17,000
Deferred income tax expense/(recovery)	10	21,136	71,701	45,006	81,483
Net Income/(Loss)		$ 74,233	$ 244,406	$ 211,719	$ 277,649
Other Comprehensive Income/(Loss)					
Unrealized gain/(loss) on foreign currency translation	12	—	1,977	—	1,357
Foreign exchange gain/(loss) on net investment hedge, net of tax	12	—	(14,094)	—	(8,719)
Total Comprehensive Income/(Loss)		$ 74,233	$ 232,289	$ 211,719	$ 270,287
Net Income/(Loss) per Share					
Basic	11	$ 0.35	$ 1.01	$ 0.98	$ 1.15
Diluted	11	$ 0.34	$ 0.99	$ 0.96	$ 1.12

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 June 30, 2023	Three months ended June 30, 2022	Six months ended June 30, 2023	Six months ended June 30, 2022
Share Capital				
Balance, beginning of period	$ 2,811,708	$ 3,070,678	$ 2,837,329	$ 3,094,061
Purchase of common shares under Normal Course Issuer Bid	(35,653)	(69,074)	(68,503)	(100,416)
Share-based compensation – treasury settled	33	—	7,262	7,959
Balance, end of period	$ 2,776,088	$ 3,001,604	$ 2,776,088	$ 3,001,604
Paid-in Capital				
Balance, beginning of period	$ 34,295	$ 36,110	$ 50,457	$ 50,881
Share-based compensation – tax withholdings settled in cash	(28)	—	(16,420)	(11,567)
Share-based compensation – treasury settled	(33)	—	(7,262)	(7,959)
Share-based compensation – non-cash	4,729	5,733	12,188	10,488
Balance, end of period	$ 38,963	$ 41,843	$ 38,963	$ 41,843
Accumulated Deficit				
Balance, beginning of period	$ (1,406,049)	$ (2,218,865)	$ (1,509,832)	$ (2,238,325)
Net income/(loss)	74,233	244,406	211,719	277,649
Purchase of common shares under Normal Course Issuer Bid	(19,125)	(23,854)	(40,835)	(29,719)
Dividends declared(1)	(11,756)	(9,940)	(23,749)	(17,858)
Balance, end of period	$ (1,362,697)	$ (2,008,253)	$ (1,362,697)	$ (2,008,253)
Accumulated Other Comprehensive Income/(Loss)				
Balance, beginning of period	$ (301,341)	$ (292,552)	$ (301,341)	$ (297,307)
Unrealized gain/(loss) on foreign currency translation	—	1,977	—	1,357
Foreign exchange gain/(loss) on net investment hedge, net of tax	—	(14,094)	—	(8,719)
Balance, end of period	$ (301,341)	$ (304,669)	$ (301,341)	$ (304,669)
Total Shareholders' Equity	$ 1,151,013	$ 730,525	$ 1,151,013	$ 730,525

(1) For the three and six months ended June 30, 2023, dividends declared were $0.055 per share and $0.110 per share, respectively (2022 – $0.043 per share and $0.076 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 June 30, 2023	Three months ended June 30, 2022	Six months ended June 30, 2023	Six months ended June 30, 2022
Operating Activities					
Net income/(loss)		$ 74,233	$ 244,406	$ 211,719	$ 277,649
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		85,117	70,090	172,226	136,781
Changes in fair value of derivative instruments	12	7,247	(91,275)	13,591	42,057
Deferred income tax expense/(recovery)	10	21,136	71,701	45,006	81,483
Unrealized foreign exchange (gain)/loss on working capital	9	(527)	(3,292)	(712)	(2,121)
Share-based compensation and general and administrative	8, 11	4,625	5,634	11,988	10,294
Other expense/(income)	4	4,739	(97)	3,089	12,556
Amortization of debt issuance costs	5	394	351	788	704
Translation of U.S. dollar cash held in parent company	9	—	(125)	—	(115)
Investing activities in Other income		(340)	—	(662)	—
Asset retirement obligation settlements	6	(2,088)	(2,349)	(8,870)	(11,144)
Changes in non-cash operating working capital	13	(7,938)	(44,184)	(20,164)	(101,292)
Cash flow from/(used in) operating activities		186,598	250,860	427,999	446,852
Financing Activities					
Drawings from/(repayment of) bank credit facilities	5	93,505	48,709	37,189	(55,700)
Repayment of senior notes	5	(59,600)	(79,600)	(59,600)	(79,600)
Purchase of common shares under Normal Course Issuer Bid	11	(54,778)	(92,928)	(109,338)	(130,135)
Share-based compensation – tax withholdings settled in cash	11	(28)	—	(16,420)	(11,567)
Dividends	11	(11,756)	(9,940)	(23,749)	(17,858)
Cash flow from/(used in) financing activities		(32,657)	(133,759)	(171,918)	(294,860)
Investing Activities					
Capital and office expenditures	13	(174,882)	(115,040)	(268,805)	(190,067)
Canadian divestments	4, 13	7,043	—	12,234	—
Property and land acquisitions		(1,638)	(1,469)	(3,386)	(3,410)
Property and land divestments		(94)	(4,462)	2,639	2,119
Cash flow from/(used in) investing activities		(169,571)	(120,971)	(257,318)	(191,358)
Effect of exchange rate changes on cash and cash equivalents		527	6,545	712	3,424
Change in cash and cash equivalents		(15,103)	2,675	(525)	(35,942)
Cash and cash equivalents, beginning of period		52,578	22,731	38,000	61,348
Cash and cash equivalents, end of period		$ 37,475	$ 25,406	$ 37,475	$ 25,406

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 six months ended June 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 June 30, 2023 ($ thousands)	**Cost**	**Accumulated Depletion, Depreciation, and Impairment**	**Net Book Value**
Crude oil and natural gas properties(1)	$ 7,539,052	$ (6,051,730)	$ 1,487,322
Other capital assets	100,553	(90,716)	9,837
Total PP&E	$ 7,639,605	$ (6,142,446)	$ 1,497,159

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 June 30, 2023, the current and long-term portion of the outstanding loan receivable from one of the purchasers of $16.8 million and $5.3 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 June 30, 2023, the common shares of one of the purchasers had a fair value of $20.1 million (December 31, 2022 – $23.1 million) resulting in unrealized losses of $5.0 million and $3.5 million for the three and six months ended June 30, 2023, respectively, recognized in Other expense/(income) on the Condensed Consolidated Statements of Income/(Loss). 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)	June 30, 2023	December 31, 2022
Current:		
Senior notes	$ 80,600	$ 80,600
Long-term:		
Bank credit facilities	93,505	56,316
Senior notes	63,000	122,600
Total debt	$ 237,105	$ 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 $2.4 million in relation to the SLL bank credit facilities were netted against the bank credit facilities at June 30, 2023. For the three and six months ended June 30, 2023, total amortization of debt issuance costs amounted to $0.4 million and $0.8 million, respectively (2022 – $0.3 million and $0.7 million, respectively).

Senior Notes

During the three months ended June 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	4 equal annual installments beginning September 3, 2023	3.79%	$200,000	$84,000
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 June 30, 2023	$ 143,600

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)	June 30, 2023	December 31, 2022
Current portion of long-term debt	$ 80,600	$ 80,600
Long-term debt	156,505	178,916
Total debt	$ 237,105	$ 259,516
Less: Cash and cash equivalents	(37,475)	(38,000)
Net debt	$ 199,630	$ 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 June 30,		Six months ended June 30,	
($ thousands)	2023	2022	2023	2022
Cash flow from/(used in) operating activities	$ 186,598	$ 250,860	$ 427,999	$ 446,852
Asset retirement obligation settlements	2,088	2,349	8,870	11,144
Changes in non-cash operating working capital	7,938	44,184	20,164	101,292
Adjusted funds flow	$ 196,624	$ 297,393	$ 457,033	$ 559,288

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)	June 30, 2023	December 31, 2022
Net debt	$ 199,630	$ 221,516
Trailing adjusted funds flow	1,128,034	1,230,289
Net debt to adjusted funds flow ratio	0.2x	0.2x

6) ASSET RETIREMENT OBLIGATION (“ARO”)

($ thousands)	June 30, 2023	December 31, 2022
Balance, beginning of year	$ 114,662	$ 132,814
Change in estimates	7,782	48,419
Property acquisition and development activity	2,806	3,985
Divestments	—	(58,284)
Settlements	(8,870)	(17,401)
Government assistance	—	(1,744)
Accretion expense	2,670	6,873
Balance, end of period	$ 119,050	$ 114,662

Enerplus has estimated the present value of its ARO to be $119.1 million at June 30, 2023 based on a total undiscounted uninflated liability of $273.3 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 is reflected as a reduction to ARO. For the three and six months ended June 30, 2022, Enerplus benefited from $0.1 million and $0.5 million, respectively, in government assistance, which has been recorded as part of Other expense/(income) in the Condensed Consolidated Statements of Income/(Loss).

For the six months ended June 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 six months ended June 30, 2023 and 2022 are as follows:

Three months ended June 30, 2023 ($ thousands)	**Total revenue**	**Crude oil[1]**	**Natural gas[1]**	**Natural gas liquids and other[1][2]**
United States	$ 350,939	$ 313,729	$ 21,967	$ 15,243

Three months ended June 30, 2022 ($ thousands)	**Total revenue**	**Crude oil[1]**	**Natural gas[1]**	**Natural gas liquids and other[1][2]**
United States	$ 578,260	$ 433,774	$ 119,972	$ 24,514
Canada	49,757	43,449	4,481	1,827
Total	$ 628,017	$ 477,223	$ 124,453	$ 26,341

Six months ended June 30, 2023 ($ thousands)	**Total revenue**	**Crude oil[1]**	**Natural gas[1]**	**Natural gas liquids and other[1][2]**
United States	$ 764,121	$ 639,190	$ 92,328	$ 32,603

Six months ended June 30, 2022 ($ thousands)	**Total revenue**	**Crude oil[1]**	**Natural gas[1]**	**Natural gas liquids and other[1][2]**
United States	$ 1,050,507	$ 791,431	$ 207,468	$ 51,608
Canada	90,662	79,996	7,262	3,404
Total	$ 1,141,169	$ 871,427	$ 214,730	$ 55,012

(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 six months ended June 30, 2023 (2022 - $0.1 million and $0.3 million, respectively).

8) GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended June 30,		**Six months ended June 30,**	
($ thousands)	**2023**	**2022**	**2023**	**2022**
General and administrative expense excluding share-based compensation[1]	$ 10,304	$ 9,291	$ 23,165	$ 20,394
Share-based compensation expense	4,770	5,396	11,341	11,874
General and administrative expense	$ 15,074	$ 14,687	$ 34,506	$ 32,268

(1) Includes a non-cash lease credit of $104 and $200 for the three and six months ended June 30, 2023 (2022 – credit of $99 and $194, respectively).

9) FOREIGN EXCHANGE

	Three months ended June 30,		**Six months ended June 30,**	
($ thousands)	**2023**	**2022**	**2023**	**2022**
Realized:				
Foreign exchange (gain)/loss	$ (267)	$ 185	$ (179)	$ (109)
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company	—	(125)	—	(115)
Unrealized:				
Foreign exchange (gain)/loss on Canadian dollar working capital in parent company	(527)	—	(712)	—
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company	—	(3,292)	—	(2,121)
Foreign exchange (gain)/loss	$ (794)	$ (3,232)	$ (891)	$ (2,345)

10) INCOME TAXES

($ thousands)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Current tax				
United States	$ 3,500	$ 12,000	$ 14,500	$ 17,000
Canada	—	—	—	—
Current tax expense/(recovery)	3,500	12,000	14,500	17,000
Deferred tax				
United States	$ 14,752	$ 73,898	$ 33,904	$ 130,366
Canada	6,384	(2,197)	11,102	(48,883)
Deferred tax expense/(recovery)	21,136	71,701	45,006	81,483
Income tax expense/(recovery)	$ 24,636	$ 83,701	$ 59,506	$ 98,483

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

The Company's deferred income tax asset recorded in Canada is $143.9 million offset by a deferred income tax liability in the U.S. of $89.3 million at June 30, 2023 (December 31, 2022 – $155.0 million deferred income tax asset in Canada offset by a $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)	Six months ended June 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	(7,340)	(68,503)	(27,925)	(266,694)
Non-cash:				
Share-based compensation – treasury settled(1)	1,306	7,262	1,358	9,962
Balance, end of period	211,251	$ 2,776,088	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 six months ended June 30, 2023 were $11.8 million and $23.8 million, respectively (2022 – $9.9 million and $17.9 million, respectively). Subsequent to the quarter, the Board of Directors approved a 9% increase to the quarterly dividend to $0.060 per share to be effective for the September 2023 payment.

During the three months ended June 30, 2023, 3.8 million common shares were repurchased and cancelled under the NCIB at an average price of $14.45 per share, for total consideration of $54.8 million. Of the amount paid, $35.7 million was charged to share capital and $19.1 million was added to accumulated deficit. During the six months ended June 30, 2023, 7.3 million common shares were repurchased and cancelled under the NCIB at an average price of $14.89 per share, for total consideration of $109.3 million. Of the amount paid, $68.5 million was charged to share capital and $40.8 million was added to accumulated deficit.

During the three months ended June 30, 2022, 7.1 million common shares were repurchased and cancelled under the NCIB at an average price of $13.13 per share, for total consideration of $92.9 million. Of the amount paid, $69.1 million was charged to share capital and $23.8 million was added to accumulated deficit. During the six months ended June 30, 2022, 10.2 million common shares were repurchased and cancelled under the NCIB at an average price of $12.74 per share, for total consideration of $130.1 million. Of the amount paid, $100.4 million was charged to share capital and $29.7 million was added to accumulated deficit.

Subsequent to June 30, 2023, the Company completed its NCIB program and repurchased 0.5 million common shares under the current NCIB at an average price of $14.63 per share, for total consideration of $7.9 million.

Subsequent to the quarter, 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.

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 June 30,		Six months ended June 30,	
($ thousands)	2023	2022	2023	2022
Cash:				
Long-term incentive plans (recovery)/expense	$ 41	$ 296	$ (847)	$ 2,394
Non-Cash:				
Long-term incentive plans (recovery)/expense	4,729	5,733	12,188	10,488
Equity swap (gain)/loss	—	(633)	—	(1,008)
Share-based compensation expense	$ 4,770	$ 5,396	$ 11,341	$ 11,874

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 six months ended June 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	77	500	483	1,060
Vested	(170)	(996)	(1,193)	(2,359)
Forfeited	—	—	(30)	(30)
Balance, end of period	540	3,193	1,581	5,314

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

Cash-settled LTI Plans

For the three and six months ended June 30, 2023, the Company recorded a cash share-based compensation recovery of $0.1 million and $0.8 million, respectively (2022 – $0.3 million and $2.4 million expense, respectively).

At June 30, 2023, a liability of $7.8 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 June 30, 2023 ($ thousands, except for years)	PSU(1)	RSU	Total
Cumulative recognized share-based compensation expense	$ 21,250	$ 14,108	$ 35,358
Unrecognized share-based compensation expense	8,544	6,850	15,394
Fair value	$ 29,794	$ 20,958	$ 50,752
Weighted-average remaining contractual term (years)	1.3	1.3	

(1) Includes estimated performance multipliers.

The Company directly withholds shares on PSU and RSU settlements for tax-withholding purposes. For the three and six months ended June 30, 2023, nil and $16.4 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 June 30,		Six months ended June 30,	
(thousands, except per share amounts)	2023	2022	2023	2022
Net income/(loss)	$ 74,233	$ 244,406	$ 211,719	$ 277,649
Weighted average shares outstanding – Basic	213,790	239,277	215,289	241,022
Dilutive impact of share-based compensation	5,942	7,939	5,987	7,935
Weighted average shares outstanding – Diluted	219,732	247,216	221,276	248,957
Net income/(loss) per share				
Basic	$ 0.35	$ 1.01	$ 0.98	$ 1.15
Diluted	$ 0.34	$ 0.99	$ 0.96	$ 1.12

12) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At June 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 June 30, 2023, the senior notes had a carrying value of $143.6 million and a fair value of $133.4 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 June 30, 2023, the loan receivable had a carrying value of $22.1 million and a fair value of $21.4 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 six months ended June 30, 2023 and 2022:

	Three months ended June 30,		Six months ended June 30,		Income Statement
Unrealized Gain/(Loss) ($ thousands)	2023	2022	2023	2022	Presentation
Equity Swaps	$ —	$ 633	$ —	$ 1,008	G&A expense
Commodity Contracts:					
Crude oil	1,480	68,513	5,223	(27,193)	Commodity derivative instruments
Natural gas	(8,727)	22,129	(18,814)	(15,872)	
Total unrealized gain/(loss)	$ (7,247)	$ 91,275	$ (13,591)	$ (42,057)	

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

($ thousands)	Three months ended June 30, 2023	Three months ended June 30, 2022	Six months ended June 30, 2023	Six months ended June 30, 2022
Unrealized change in fair value gain/(loss)	$ (7,247)	$ 90,642	$ (13,591)	$ (43,065)
Net realized cash gain/(loss)	14,208	(138,195)	48,517	(211,298)
Commodity contracts gain/(loss)	$ 6,961	$ (47,553)	$ 34,926	$ (254,363)

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

	June 30, 2023		December 31, 2022	
	Assets	Liabilities	Assets	Liabilities
($ thousands)	Current	Current	Current	Current
Commodity Contracts:				
Crude oil	$ 8,269	$ 2,195	$ 9,834	$ 10,421
Natural gas	7,894	—	26,708	—
Total	$ 16,163	$ 2,195	$ 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 June 30, 2023, the fair value of Enerplus' commodity contracts totaled a net asset of $14.0 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 August 8, 2023:

Crude Oil Instruments:

Instrument Type(1)(2)	Jul 1, 2023 - Oct 31, 2023		Nov 1, 2023 - Dec 31, 2023	
	bbls/day	$/bbl	bbls/day	$/bbl
WTI Purchased Put	5,000	85.00	5,000	85.00
WTI Sold Put	5,000	65.00	5,000	65.00
WTI Sold Call	5,000	128.16	5,000	128.16
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 $1.07/bbl from July 1, 2023 – December 31, 2023.
(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]	July 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 six months ended June 30, 2023, there were no unrealized foreign exchange gains or losses recorded in Other Comprehensive Income/(Loss) compared to an unrealized loss of $14.1 million and $8.7 million, respectively on Enerplus' U.S. denominated senior notes and bank credit facilities for the three and six months ended June 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 June 30, 2023, approximately 61% of Enerplus' debt was based on fixed interest rates and 39% on floating interest rates (December 31, 2022 – 78% fixed and 22% floating), with a weighted average interest rates of 4.0% and 6.4%, respectively (December 31, 2022 – 4.1% and 5.7%, respectively). At June 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 June 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 June 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 June 30, 2023 was $3.9 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 June 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

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2023	2022	2023	2022
Accounts receivable	$ (9,170)	$ (105,492)	$ 35,716	$ (160,083)
Other assets – operating	3,549	487	9,290	4,792
Accounts payable – operating	(2,317)	60,821	(65,170)	53,999
Non-cash operating activities	$ (7,938)	$ (44,184)	$ (20,164)	$ (101,292)

b) Changes in Non-Cash Investing Working Capital

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2023	2022	2023	2022
Accounts payable – investing(1)	$ 666	$ 17,984	$ 39,615	$ 42,290
Other current assets – investing(1)	6,824	—	12,439	—
Non-cash investing activities	$ 7,490	$ 17,984	$ 52,054	$ 42,290

(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.

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2023	2022	2023	2022
Settlement on divestment(1)	$ —	$ 13,053	$ —	$ 13,053

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

($ thousands)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Loan receivable	$ 4,607	$ —	$ 9,476	$ —
Accounts receivable	1,162	—	1,162	—
Non-cash working capital – Canadian divestments(1)	$ 5,769	$ —	$ 10,638	$ —

(1) Refer to Note 4.

c) Cash Income Taxes and Interest Payments

($ thousands)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Income taxes paid	$ 15,232	$ 2,607	$ 15,235	$ 2,614
Interest paid	$ 4,156	$ 7,193	$ 7,109	$ 12,399

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, CO

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
Enerplus Resources (USA) Corporation

LEGAL COUNSEL
Blake, Cassels & Graydon LLP
Calgary, Alberta

AUDITORS
KPMG LLP
Calgary, Alberta

TRANSFER AGENT
TSX Trust (Canada)
Toronto, Ontario
Toll free: 1.800.387.0825

American Stock Transfer & Trust Company, LLC
Brooklyn, New York
Toll free: 1.800.937.5449

INDEPENDENT RESERVE ENGINEERS
McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS
Toronto Stock Exchange: ERF
New York Stock Exchange: ERF

CANADA OFFICE
Dome Tower
Suite 3000, 333 – 7th Avenue SW
Calgary, Alberta T2P 2Z1

Telephone: 403.298.2200
Investor Relations: 1.800.319.6462

U.S. OFFICE
U.S. Bank Tower
Suite 2200, 950 – 17th Street
Denver, Colorado 80202-2805

Telephone: 720.279.5500
Fax: 720.279.5550

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

ENERPLUS

Dome Tower
Suite 3000
333 7th Avenue SW
Calgary, Alberta Canada
T2P 2Z1

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Suite 2200
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80202-2805

Telephone: 720.279.5500
Fax: 720.729.5550

www.enerplus.com
investorrelations@enerplus.com