enerPLUS

Second Quarter Report

Six Months Ended June 30, 2020

SELECTED FINANCIAL RESULTS	Three months ended June 30,		Six months ended June 30,	
	2020	2019	2020	2019
Financial (CDN$, thousands, except ratios)				
Net Income/(Loss)	$ (609,323)	$ 85,084	$ (606,447)	$ 104,242
Adjusted Net Income/(Loss)[1]	(41,185)	74,366	(20,095)	146,824
Cash Flow from Operating Activities	90,560	236,991	213,299	345,942
Adjusted Funds Flow[1]	69,997	186,038	183,224	354,793
Dividends to Shareholders - Declared	6,675	7,034	13,345	14,196
Total Debt Net of Cash[1]	518,094	359,006	518,094	359,006
Capital Spending	40,084	207,208	203,709	368,001
Property and Land Acquisitions	3,416	1,911	5,672	4,936
Property Divestments	(63)	9,601	5,515	10,067
Net Debt to Adjusted Funds Flow Ratio[1]	1.0x	0.5x	1.0x	0.5x
Financial per Weighted Average Shares Outstanding				
Net Income /(Loss) - Basic	$ (2.74)	$ 0.36	$ (2.73)	$ 0.44
Net Income/(Loss) - Diluted	(2.74)	0.36	(2.73)	0.43
Weighted Average Number of Shares Outstanding (000's) - Basic	222,557	235,490	222,457	237,197
Weighted Average Number of Shares Outstanding (000's) - Diluted	222,557	238,189	222,457	239,947
Selected Financial Results per BOE[2][3]				
Oil & Natural Gas Sales[4]	$ 19.53	$ 44.00	$ 26.11	$ 44.33
Royalties and Production Taxes	(5.15)	(11.26)	(6.74)	(10.90)
Commodity Derivative Instruments	6.73	(0.13)	5.12	0.55
Cash Operating Expenses	(6.84)	(7.84)	(7.90)	(8.26)
Transportation Costs	(4.28)	(4.02)	(4.11)	(3.97)
Cash General and Administrative Expenses	(1.14)	(1.26)	(1.26)	(1.39)
Cash Share-Based Compensation	(0.15)	0.07	0.09	(0.04)
Interest, Foreign Exchange and Other Expenses	(1.69)	(0.79)	(1.29)	(0.75)
Current Income Tax Recovery	1.81	1.52	0.85	1.14
Adjusted Funds Flow[1]	$ 8.82	$ 20.29	$ 10.87	$ 20.71

SELECTED OPERATING RESULTS	Three months ended June 30,		Six months ended June 30,	
	2020	2019	2020	2019
Average Daily Production[3]				
Crude Oil (bbls/day)	43,168	48,141	46,106	44,642
Natural Gas Liquids (bbls/day)	4,929	4,720	5,137	4,552
Natural Gas (Mcf/day)	235,579	287,000	249,246	272,863
Total (BOE/day)	87,360	100,694	92,784	94,671
% Crude Oil and Natural Gas Liquids	55%	52%	55%	52%
Average Selling Price [3][4]				
Crude Oil (per bbl)	$ 30.55	$ 74.42	$ 41.59	$ 70.82
Natural Gas Liquids (per bbl)	(0.96)	17.96	6.16	18.53
Natural Gas (per Mcf)	1.63	2.63	1.87	3.46
Net Wells Drilled	3	13	37	30

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

Average Benchmark Pricing	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
WTI crude oil (US$/bbl)	$ 27.85	$ 59.81	$ 37.01	$ 57.36
Brent (ICE) crude oil (US$/bbl)	33.27	68.32	42.12	66.11
NYMEX natural gas – last day (US$/Mcf)	1.72	2.64	1.83	2.89
USD/CDN average exchange rate	1.39	1.34	1.37	1.33

Share Trading Summary For the three months ended June 30, 2020	CDN(1) - ERF (CDN$)	U.S.(2) - ERF (US$)
High	$ 5.18	$ 3.73
Low	$ 1.95	$ 1.38
Close	$ 3.82	$ 2.83

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

2020 Dividends per Share	CDN$	US$(1)
First Quarter Total	$ 0.03	$ 0.02
Second Quarter Total	$ 0.03	$ 0.02
Total	$ 0.06	$ 0.04

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

NEWS RELEASE

HIGHLIGHTS

- Second quarter production was 87,360 BOE per day, including liquids of 48,097 barrels per day
- Adjusted funds flow of $70 million exceeded capital spending in the second quarter, generating free cash flow of $30 million, with additional free cash flow forecast during the second half of 2020
- Reinstated 2020 production guidance: 88,000 to 90,000 BOE per day, including 49,000 to 50,000 barrels per day of liquids
- 2020 capital spending unchanged at $300 million
- Maintained low financial leverage; net debt to adjusted funds flow ratio was 1.0 times at quarter-end
- Advantaged position for rapid future capital deployment with drilled uncompleted well inventory

“We have seen extraordinary volatility in the first 6-months of 2020 as the COVID-19 pandemic and OPEC supply issues meaningfully impacted the industry,” commented Ian C. Dundas, President and Chief Executive Officer of Enerplus. “Enerplus took decisive action to respond to this instability, enabling the company to navigate this period and maintain financial resilience. Despite the challenging conditions, we delivered strong operational execution and cost performance in the second quarter, which has helped position the business to deliver free cash flow in 2020 and maintain our top-quartile balance sheet strength.”

SECOND QUARTER SUMMARY

Production

Production in the second quarter of 2020 was 87,360 BOE per day, a decrease of 13% compared to the same period a year ago, and 11% lower than the prior quarter. Crude oil and natural gas liquids production in the second quarter of 2020 was 48,097 barrels per day, a decrease of 9% compared to the same period a year ago, and 12% lower than the prior quarter.

The lower production was due to the temporary curtailment of production during the second quarter and the suspension of all operated drilling and completion activity in response to the significant decline in crude oil prices. Enerplus curtailed approximately 25% of its liquids volumes in May to protect against selling oil at negative margins. The Company began restoring curtailed volumes in June as oil prices improved, with curtailed volumes largely restored in July.

Financial Highlights

Enerplus reported adjusted funds flow for the second quarter of 2020 of $70.0 million compared to $186.0 million in the second quarter of 2019. The decrease from the prior year period was due to lower commodity prices and production levels in the second quarter of 2020.

The Company reported a net loss of $609.3 million in the second quarter of 2020 compared to net income of $85.1 million in the same period in 2019. The decrease from the prior year period was primarily the result of non-cash impairments and lower commodity prices and production in the second quarter of 2020. In the second quarter of 2020, Enerplus recorded a $426.8 million non-cash impairment on PP&E and a $202.8 million non-cash impairment on goodwill as a result of the continued market volatility and low commodity price environment. Excluding these impairments and certain other non-cash or non-recurring items, Enerplus’ second quarter 2020 adjusted net loss was $41.2 million, or $0.19 per share, compared to adjusted net income of $74.4 million, or $0.32 per share in the second quarter of 2019. Enerplus recorded a current tax recovery of $14.4 million in the second quarter of 2020 related to the recognition of the Company’s final U.S. Alternative Minimum Tax refund.

Enerplus’ second quarter 2020 realized Bakken oil price differential was US$4.36 per barrel below WTI, compared to US$3.00 per barrel below WTI in the second quarter of 2019. Bakken oil differentials materially weakened during April as refineries reduced purchases given the significant reduction in demand for refined products due to the COVID-19 pandemic. Despite this weakness, Enerplus outperformed the benchmark index (Bakken DAPL – WTI) by temporarily curtailing production during the weakest period and through the diversification of sales into higher priced markets.

The Company’s realized Marcellus natural gas price differential was US$0.49 per Mcf below NYMEX during the second quarter of 2020 compared to US$0.57 per Mcf below NYMEX in the second quarter of 2019. The second quarter differentials reflect lower seasonal natural gas demand in the local market.

In the second quarter of 2020, Enerplus’ operating expenses were $6.84 per BOE, compared to $7.84 per BOE during the same period in 2019. The lower unit operating expenses were primarily driven by the proactive price related shut-in of the Company’s highest unit expense oil wells, and from reduced well servicing activity and lower service costs.

Second quarter transportation costs were $4.28 per BOE and cash general and administrative expenses were $1.14 per BOE.

Exploration and development capital spending in the second quarter was $40.1 million, reflecting strong operational execution which drove continued improvement in total well costs. Capital activity in the quarter was associated with drilling 2.5 net wells and bringing 8.9 net wells on production, including operated and non-operated activity across the Company.

Enerplus ended the second quarter of 2020 with a strong balance sheet and significant liquidity. The Company had total debt of $524.3 million, cash of $6.2 million and US$599 million available on its US$600 million bank credit facility. The Company's net debt to adjusted funds flow ratio was 1.0 times at quarter-end. During the second quarter, Enerplus made scheduled principal repayments of US$81.6 million on its 2009 and 2012 senior notes.

Asset Activity

Williston Basin production averaged 44,081 BOE per day (81% oil) during the second quarter of 2020, a decrease of 6% compared to the same period a year ago, and 11% lower than the prior quarter, reflecting the curtailed production during the second quarter of 2020. During the second quarter, and prior to the suspension of the Company's drilling and completion program in mid-April, the Company drilled one gross operated well and completed a seven-well pad (97% average working interest). The seven-well pad was brought on production during June concurrent with improving oil prices. Enerplus currently has 33 gross (27 net) operated drilled uncompleted wells in inventory in North Dakota.

Marcellus production averaged 197 MMcf per day during the second quarter of 2020, a decrease of 17% compared to the same period in 2019, and 9% lower than the prior quarter. The Company participated in drilling 15 gross non-operated wells (4% average working interest) and brought 10 gross non-operated wells (2% average working interest) on production during the quarter.

Canadian waterflood production averaged 6,338 BOE per day (94% oil) during the second quarter of 2020, a decrease of 31% compared to the same period in 2019, and 23% lower than the prior quarter, reflecting the curtailed production during the second quarter of 2020.

In the DJ Basin, the Company participated in drilling 15 gross non-operated wells (6% average working interest) in the second quarter and brought two gross operated wells (90% average working interest) on production. Enerplus currently has three gross (2.6 net) operated drilled uncompleted wells in inventory in the DJ Basin.

2020 GUIDANCE AND 2021 MAINTENANCE CAPITAL

Although there remains significant uncertainty regarding the timing and path forward for a global economic recovery from the impacts of COVID-19, given the relative stability in oil prices since late in the second quarter, Enerplus is reinstating 2020 guidance.

Enerplus expects its 2020 production to average 88,000 to 90,000 BOE per day, including 49,000 to 50,000 barrels per day of crude oil and natural gas liquids. Enerplus is maintaining its $300 million capital budget in 2020. Remaining activity is primarily focused on non-operated drilling and completions in the Marcellus and North Dakota, along with four operated completions in North Dakota planned for the fourth quarter. In total, the Company expects to complete approximately six net wells (operated and non-operated) in North Dakota and two net wells in the Marcellus in the second half of 2020. Enerplus expects this plan to generate free cash flow in 2020 based on current market conditions.

With this outlook, Enerplus estimates it could maintain its second half 2020 liquids production flat in 2021 for approximately $300 million. This maintenance capital estimate includes an allocation for drilling in 2021 to provide an inventory of wells to complete in 2022, and an allocation for the Company's Marcellus natural gas asset.

In early July, a U.S. district court ordered the Dakota Access Pipeline ("DAPL") to cease operations after it found that, due to deficiencies in the original environmental review, the U.S. Army Corps of Engineers are required to complete a more thorough Environmental Impact Statement. On August 5, an appeals court granted the pipeline owners' request for a stay over the lower court order requiring the pipeline to cease operations. As a result, there is no outstanding court order in place requiring DAPL to shut down at this time and the legal process is ongoing.

As a result of the above and assuming DAPL continues to operate, the Company expects the market price for Bakken oil to remain constructive and estimates its realized 2020 Bakken oil price differential will average approximately US$5.00 per barrel below WTI. For the second half of 2020, Enerplus has fixed differential sales agreements in North Dakota for approximately 16,000 barrels per day at an estimated price of US$6.00 per barrel below WTI, based on current market prices.

2020 Guidance Summary

The Company's reinstated guidance for 2020 is in the table below.

	Guidance
Capital spending	$300 million
Average annual production	88,000 - 90,000 BOE/day
Average annual crude oil and natural gas liquids production	49,000 - 50,000 bbls/day
Average royalty and production tax rate	26%
Operating expense	$8.25/BOE
Transportation expense	$4.15/BOE
Cash G&A expense	$1.40/BOE

2020 Full-Year Differential/Basis Outlook(1)	
U.S. Bakken crude oil differential (compared to WTI crude oil)(2)	US$(5.00)/bbl
Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.45)/Mcf

(1) Excluding transportation costs.
(2) Based on the continued operation of the Dakota Access Pipeline.

PRICE RISK MANAGEMENT

As of August 6, 2020 Enerplus has an average of 24,500 barrels per day of crude oil hedged through financial derivative contracts for the remainder of 2020 and 6,000 barrels per day for the first half of 2021.

	WTI Crude Oil (US$/bbl)(1)(2)		
	Jul 1, 2020 – Sep 30, 2020	Oct 1, 2020 – Dec 31, 2020	Jan 1, 2021 – Jun 30, 2021
Swaps			
Volume (bbls/d)	7,000	—	—
Sold Swaps	$ 36.02	—	—
Put Spreads			
Volume (bbls/d)	16,000	16,000	—
Sold Puts	$ 46.88	$ 46.88	—
Purchased Puts	$ 57.50	$ 57.50	—
Three Way Collars			
Volume (bbls/d)	5,000	5,000	6,000
Sold Puts	$ 48.00	$ 48.00	$ 32.00
Purchased Puts	$ 56.25	$ 56.25	$ 40.00
Sold Calls	$ 65.00	$ 65.00	$ 50.00

(1) All of the sold puts on the put spreads are settled annually at the end of 2020 rather than monthly.
(2) The total average deferred premium spent on these hedges is US$1.75/bbl from July 1, 2020 to December 31, 2020 and US$0.03/bbl from January 1, 2021 to June 30, 2021.

DIRECTOR RETIREMENT

Enerplus announced the retirement of Mr. Michael Culbert from the Company's board of directors. Mr. Culbert has been a valued member of the board of directors since his appointment in March 2014 and has provided the board with insightful guidance gained through his long career in the oil and gas industry. Enerplus wishes to acknowledge and thank him for his many contributions and dedicated service.

SECOND QUARTER PRODUCTION AND OPERATIONAL SUMMARY TABLES

Average Daily Production(1)

	Three months ended June 30, 2020				Six months ended June 30, 2020			
	Crude Oil (Mbbl/d)	NGL (Mbbl/d)	Natural Gas (MMcf/d)	Total (Mboe/d)	Crude Oil (Mbbl/d)	NGL (Mbbl/d)	Natural Gas (MMcf/d)	Total (Mboe/d)
Williston Basin	35.6	4.2	25.2	44.1	37.7	4.4	28.0	46.8
Marcellus	—	—	196.7	32.8	—	—	206.3	34.4
Canadian Waterfloods	6.0	0.1	1.8	6.3	6.8	0.1	2.2	7.3
Other(2)	1.6	0.6	11.8	4.2	1.5	0.7	12.7	4.3
Total	**43.2**	**4.9**	**235.6**	**87.4**	**46.1**	**5.1**	**249.2**	**92.8**

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

Summary of Wells Drilled[1]

	Three months ended June 30, 2020				Six months ended June 30, 2020			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	1.0	1.0	—	—	19.0	18.8	3.0	1.1
Marcellus	—	—	15.0	0.6	—	—	30.0	1.7
Canadian Waterfloods	—	—	—	—	10.0	10.0	—	—
Other[2]	—	—	15.0	0.9	5.0	4.4	16.0	0.9
Total	**1.0**	**1.0**	**30.0**	**1.5**	**34.0**	**33.2**	**49.0**	**3.7**

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

Summary of Wells Brought On-Stream[1]

	Three months ended June 30, 2020				Six months ended June 30, 2020			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	7.0	6.8	—	—	18.0	15.8	7.0	1.9
Marcellus	—	—	10.0	0.2	—	—	20.0	0.6
Canadian Waterfloods	—	—	—	—	—	—	—	—
Other[2]	2.0	1.8	—	—	2.0	1.8	1.0	—
Total	**9.0**	**8.6**	**10.0**	**0.2**	**20.0**	**17.6**	**28.0**	**2.5**

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

Currency and Accounting Principles
All amounts in this news release are stated in Canadian 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 Measures".

Barrels of Oil Equivalent
This news release also contains references to "BOE" (barrels of oil equivalent). Enerplus has adopted the standard of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOEs 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.

Presentation of Production Information
Under U.S. GAAP oil and gas sales are generally presented net of royalties and U.S. industry protocol is to present production volumes net of royalties. Under Canadian industry protocol oil and gas sales and production volumes are presented on a gross basis before deduction of royalties. To continue to be comparable with its Canadian peer companies, the summary results contained within this news release presents Enerplus' production and BOE measures on a before royalty company interest basis. All production volumes and revenues presented herein are reported on a "company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest. All references to "liquids" in this news release include light and medium crude oil, heavy oil and tight oil (all together referred to as "crude oil") and natural gas liquids on a combined basis.

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: expected capital spending levels in 2020 and impact thereof on our production levels and land holdings, as well as our free cash flow; expected production volumes; expected operating strategy in 2020, including the proportion of Enerplus' production that may be curtailed and the effect of such actions on its properties, operations and financial position; the proportion of our anticipated oil and gas production that is hedged and the expected effectiveness of such hedges in protecting our adjusted funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials, and our commodity risk management program in 2020; expectations regarding our realized oil and natural gas prices; expected operating, transportation and cash G&A costs; expectations regarding our 2021 production and capital spending levels required to achieve that production; potential future non-cash PP&E impairments, as well as relevant factors that may affect such impairment; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes; Enerplus' costs reduction *initiatives; and the amount of future cash dividends that we may pay to our shareholders.*

The forward-looking information contained in this news release reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure and/or low commodity price environment will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to comply with our debt covenants; the availability of third party services; and the extent of our liabilities. In addition, our expected 2020 capital expenditures and operating strategy described in this news release is based on the rest of the year prices and exchange rate of: a WTI price of US$41.19/bbl, a NYMEX price of US$1.94/Mcf, and a USD/CDN exchange rate of 1.35. 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 COVID-19; continued low commodity prices environment or further decline and/or volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our MD&A, our Annual Information Form, our Annual MD&A and Form 40-F as at December 31, 2019).

The forward-looking information contained in this news release speak 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

NON-GAAP MEASURES

In this news release, we use the terms "adjusted funds flow", "adjusted net income", "free cash flow", "net debt to adjusted funds flow ratio" and "total debt net of cash" as measures to analyze financial and operating performance, leverage and liquidity. "Adjusted funds flow" is calculated as cash flow generated from operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures. "Adjusted net income" is calculated as net income adjusted for unrealized derivative instrument gain/loss, asset impairment, unrealized foreign exchange gain/loss, the tax effect of these items, goodwill impairment, the impact of statutory changes to the Company's corporate tax rate, and the valuation allowance on our deferred income tax assets. "Free cash flow" is calculated as adjusted funds flow minus capital spending. "Net debt to adjusted funds flow ratio" is calculated as total debt net of cash and cash equivalents, divided by a trailing 12 months of adjusted funds flow. "Total debt net of cash" is calculated as senior notes plus any outstanding bank credit facility balance, minus cash and cash equivalents. Calculation of these terms is described in Enerplus' MD&A under the "Non-GAAP Measures" section.

Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "adjusted funds flow", "net debt to adjusted funds flow", and "total debt net of cash" are useful supplemental measures as they provide an indication of the results generated by Enerplus' principal business activities. However, these measures are not measures recognized by U.S. GAAP and do not have a standardized meaning prescribed by U.S. GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers. For reconciliation of these measures to the most directly comparable measure calculated in accordance with U.S. GAAP, and further information about these measures, see disclosure under "Non-GAAP Measures" in Enerplus' Second Quarter 2020 MD&A.

Electronic copies of Enerplus Corporation's Second Quarter 2020 MD&A and Financial Statements, along with other public information including investor presentations, are available on its website at www.enerplus.com. Shareholders may, upon request, receive a printed copy of the Company's audited financial statements at any time. 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 6, 2020 and is to be read in conjunction with:

- the unaudited interim condensed consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three and six months ended June 30, 2020 and 2019 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2019 and 2018 and for the years ended December 31, 2019, 2018 and 2017; and
- our MD&A for the year ended December 31, 2019 (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 this MD&A and in the Annual MD&A and "Risk Factors" in Enerplus' annual information form for the year ended December 31, 2019 (the "Annual Information Form").

BASIS OF PRESENTATION

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

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

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

OVERVIEW

The onset of the coronavirus ("COVID-19") pandemic in mid-March resulted in a sudden global economic downturn and significant challenges for our industry. In response to a dramatic decline in crude oil demand and historically low prices, we began temporarily curtailing production from certain wells across our crude oil and natural gas liquids properties and suspended our operated drilling and completions activity in North Dakota during the second quarter.

As a result, our crude oil and natural gas liquids production decreased 12% to 48,097 bbls/day, compared to 54,390 bbls/day in the first quarter of 2020. Total average production of 87,360 BOE/day in the second quarter was also impacted by limited capital activity in the Marcellus, with natural gas production of 196,738 Mcf/day, a 9% decrease from the first quarter of 2020, and in line with our previous rest of year expectation of 185 MMcf/day to 200 MMcf/day.

Late in the second quarter, both energy equities and commodity prices began to stabilize as global economies began to reopen, with WTI benchmark prices averaging US$38.31/bbl in June, a 129% increase compared to an average of US$16.70/bbl in April. We began restoring curtailed production in June as crude oil prices improved, with production largely restored in July. Although markets remain volatile and there is uncertainty surrounding the timing of a full economic recovery, global crude oil demand has begun to improve. As a result, we are reinstating our 2020 annual guidance.

We expect annual 2020 production to average 88,000 - 90,000 BOE/day, including 49,000 - 50,000 bbls/day of crude oil and natural gas liquids. We are maintaining our capital spending budget of $300 million. Remaining activity is primarily focused on non-operated drilling and completions in the Marcellus and North Dakota, along with four operated completions in North Dakota during the fourth quarter. We expect to complete approximately six net wells in North Dakota and two net wells in the Marcellus in the second half of 2020.

Capital expenditures during the second quarter of 2020 totaled $40.1 million compared to $163.6 million during the first quarter, with approximately 68% of our annual capital budget spent year to date.

Our Bakken crude oil price differential narrowed to US$4.36/bbl below WTI during the second quarter, a 17% improvement compared to US$5.26/bbl below WTI during the first quarter. Although Bakken differentials were very weak in April due to the COVID-19 demand reductions, the weak pricing was temporary as regional production was significantly reduced in May and June in response. These industry-wide production curtailments, along with our own decision to curtail some production as prices fell, impacted the supply in the basin enough to provide support for local prices through the end of the quarter. We currently expect our annual Bakken crude oil price differential to average US$5.00/bbl below WTI. This guidance assumes the continued operation of the Dakota Access Pipeline (“DAPL”), which is currently the subject of ongoing litigation.

Our Marcellus natural gas price differential widened to US$0.49/Mcf below NYMEX in the second quarter compared to US$0.38/Mcf below NYMEX during the first quarter with lower seasonal demand. We continue to expect our Marcellus natural gas price differential to average US$0.45/Mcf below NYMEX for 2020.

Operating costs for the quarter were $54.4 million or $6.84/BOE, compared to $79.0 million or $8.84/BOE in the first quarter, mainly due to lower production and less well servicing activity in the second quarter of 2020. We continue to expect average annual operating costs of $8.25/BOE.

We expect annual cash general and administrative expenses of $1.40/BOE, transportation costs of $4.15/BOE and an annual average royalty and production tax rate of 26% of oil and natural gas sales before transportation.

We reported a net loss of $609.3 million in the second quarter of 2020 compared to net income of $2.9 million in the first quarter of 2020. The decrease was primarily due to impairments recorded in the second quarter as a result of the continued market volatility and low commodity price environment, which included a $426.8 million non-cash impairment on our property, plant and equipment (“PP&E”) and a $202.8 million non-cash impairment on our goodwill. Net loss in the second quarter was also impacted by a $10.9 million loss on commodity derivative instruments and a total tax recovery of $113.4 million, compared to a $131.3 million gain on commodity derivative instruments and a total tax expense of $109.4 million recorded in the first quarter of 2020.

Cash flow from operations decreased to $90.6 million in the second quarter compared to $122.7 million in the first quarter of 2020, and adjusted funds flow decreased to $70.0 million from $113.2 million over the same period. The decrease was primarily due to a decline in realized prices and lower production during the quarter, offset by a $20.5 million increase in realized commodity derivative gains compared to the first quarter of 2020.

We continue to expect our commodity hedging program to protect a significant portion of our cash flow from operating activities and adjusted funds flow. At June 30, 2020, our crude oil commodity derivative contracts were in a net asset position of $44.0 million. As of August 6, 2020, we have hedged 24,500 bbls/day of crude oil for the remainder of 2020, and 6,000 bbls/day for 2021.

Despite the ongoing challenging market conditions, we have maintained a strong balance sheet. At June 30, 2020, total debt net of cash was $518.1 million, including senior notes of $523.2 million and cash on hand of $6.2 million, and our net debt to adjusted funds flow ratio was 1.0x. We made principal repayments of US$81.6 million on our senior notes during the second quarter. At June 30, 2020 and as of the date of this MD&A, we are in compliance with all debt covenants.

RESULTS OF OPERATIONS

Production

Daily production for the second quarter averaged 87,360 BOE/day, a decrease of 11% compared to average production of 98,209 BOE/day in the first quarter of 2020. Crude oil and natural gas liquids production decreased by 12% to 48,097 bbls/day primarily due to the temporary curtailment of certain wells across our crude oil and liquids properties during the second quarter in order to protect against selling production at negative margins. Second quarter production was further impacted by a reduction to the 2020 capital program, which suspended operated drilling and completions activity in North Dakota in mid-April. Natural gas production decreased 10% to 235,579 Mcf/day compared to 262,913 Mcf/day during the first quarter due to minimal capital activity in the Marcellus.

For the three months ended June 30, 2020, total production decreased by 13,334 BOE/day or 13%, compared to the same period in 2019, primarily due to the impact of price related crude oil and natural gas liquids production curtailments and the suspension of our operated North Dakota drilling and completions program during the second quarter of 2020.

For the six months ended June 30, 2020, total production decreased by 1,887 BOE/day or 2% compared to the same period in 2019. The decrease was mainly due to a 9% decline in natural gas production as a result of limited capital activity in the Marcellus and our decision to shut-in, abandon and reclaim our Canadian natural gas property in Tommy Lakes during the first quarter of 2020. Crude oil and natural gas liquids production increased 4% over the same period, with the impact of continued capital spending on our U.S. crude oil properties during the second half of 2019 and the first quarter of 2020 more than offsetting the impact of lower production during the second quarter of 2020.

Our crude oil and natural gas liquids weighting increased to 55% in the first six months of 2020 from 52% for the same period in 2019.

Average daily production volumes for the three and six months ended June 30, 2020 and 2019 are outlined below:

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2020**	**2019**	**% Change**	**2020**	**2019**	**% Change**
Crude oil (bbls/day)	43,168	48,141	(10%)	46,106	44,642	3%
Natural gas liquids (bbls/day)	4,929	4,720	4%	5,137	4,552	13%
Natural gas (Mcf/day)	235,579	287,000	(18%)	249,246	272,863	(9%)
Total daily sales (BOE/day)	87,360	100,694	(13%)	92,784	94,671	(2%)

We are providing annual average production guidance for 2020 of 88,000 - 90,000 BOE/day, including 49,000 - 50,000 bbls/day of crude oil and natural gas liquids. This annual production guidance is based on a capital budget of $300 million, which includes the completion of approximately six net wells in North Dakota and two net wells in the Marcellus in the second half of 2020.

Pricing

The prices received for crude oil and natural gas production directly impact our earnings, cash flow from operations, adjusted funds flow and financial condition. The following table compares quarterly average prices from the first half of 2020 to the first half of 2019 and other periods indicated:

Pricing (average for the period)	Six months ended June 30, 2020	Six months ended June 30, 2019	Q2 2020	Q1 2020	Q4 2019	Q3 2019	Q2 2019
Benchmarks							
WTI crude oil (US$/bbl)	$ 37.01	$ 57.36	$ 27.85	$ 46.17	$ 56.96	$ 56.45	$ 59.81
Brent (ICE) crude oil (US$/bbl)	42.12	66.11	33.27	50.96	62.51	62.00	68.32
NYMEX natural gas – last day (US$/Mcf)	1.83	2.89	1.72	1.95	2.50	2.23	2.64
USD/CDN average exchange rate	1.37	1.33	1.39	1.34	1.32	1.32	1.34
USD/CDN period end exchange rate	1.36	1.31	1.36	1.41	1.30	1.32	1.31
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 41.59	$ 70.82	$ 30.55	$ 51.30	$ 67.23	$ 67.76	$ 74.42
Natural gas liquids ($/bbl)	6.16	18.53	(0.96)	12.72	18.28	5.97	17.96
Natural gas ($/Mcf)	1.87	3.46	1.63	2.08	2.50	2.13	2.63
Average differentials							
Bakken DAPL – WTI (US$/bbl)	$ (5.29)	$ (2.64)	$ (5.24)	$ (5.34)	$ (5.59)	$ (2.97)	$ (2.36)
Brent (ICE) – WTI (US$/bbl)	5.11	8.75	5.42	4.79	5.55	5.55	8.51
MSW Edmonton – WTI (US$/bbl)	(6.86)	(4.74)	(6.14)	(7.58)	(5.37)	(4.66)	(4.63)
WCS Hardisty – WTI (US$/bbl)	(16.00)	(11.48)	(11.47)	(20.53)	(15.83)	(12.24)	(10.67)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.39)	(0.33)	(0.38)	(0.39)	(0.70)	(0.48)	(0.43)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	(0.21)	0.68	(0.29)	0.41	(0.11)	(0.35)	(0.31)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI (US$/bbl)	$ (4.87)	$ (3.10)	$ (4.36)	$ (5.26)	$ (4.40)	$ (3.61)	$ (3.00)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.44)	(0.25)	(0.49)	(0.38)	(0.63)	(0.44)	(0.57)
Canada crude oil – WTI (US$/bbl)	(16.34)	(10.21)	(14.49)	(17.77)	(14.80)	(13.50)	(9.99)

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

CRUDE OIL AND NATURAL GAS LIQUIDS

Our realized crude oil sales price for the second quarter of 2020 averaged $30.55/bbl, a decrease of 40% compared to the first quarter, and in line with the decline in the benchmark WTI price over the same period. The decrease was the result of the combined impact of global demand destruction resulting from the COVID-19 pandemic and a dramatic increase in the supply of Russian and Saudi Arabian crude oil in the market after the Organization of the Petroleum Exporting Countries Plus (“OPEC+”) nations failed to agree on production restrictions during the first quarter. As global supply curtailments took hold through the second quarter and with the slow reopening of global economies supporting crude oil demand, WTI prices stabilized and recovered from an average of US$16.70/bbl in April to an average of US$38.31/bbl in June.

Crude oil price differentials were also volatile during the quarter. Our realized Bakken differential improved by US$0.90/bbl during the second quarter of 2020 compared to the first quarter to average US$4.36/bbl below WTI. Differentials weakened significantly during April as refineries reduced purchases given the significant reduction in demand for end products with COVID-19 related lockdowns. Despite this weakness, we outperformed the benchmark index by temporarily curtailing production during the weakest period and through a diversification of sales into higher priced markets. Our Bakken sales price consists of a combination of in-basin monthly spot and index sales, term physical sales with fixed differential pricing versus WTI and/or Brent, and sales at the U.S. Gulf Coast delivered via firm capacity on DAPL.

In early July, a U.S. district court ordered DAPL to cease operations after it found that, due to deficiencies in the original environmental review, the U.S. Army Corps of Engineers are required to complete a more thorough Environmental Impact Statement. On August 5, an appeals court granted the pipeline owners’ request for a stay over the lower court order requiring the pipeline to cease operations. As a result, there is no outstanding court order in place requiring DAPL to shut down at this time and the legal process is ongoing.

As a result of the above and assuming DAPL continues to operate, we expect the market price for Bakken crude oil to remain constructive and expect our annual Bakken crude oil price differential to average approximately US$5.00/bbl below WTI in 2020. For the second half of 2020, we have fixed differential sales agreements in North Dakota for approximately 16,000 bbls/day at an estimated price of approximately US$6.00/bbl below WTI, based on current market prices.

Our realized price differential for Canadian crude oil production narrowed by US$3.28/bbl compared to the first quarter of 2020, which was in line with changes to the underlying benchmark prices for Canadian crude oil.

Our realized sales price for natural gas liquids averaged ($0.96)/bbl during the second quarter of 2020. Natural gas liquids price weakness was mainly attributable to a prior period pricing adjustment and the deterioration of benchmark pricing.

NATURAL GAS

Our realized natural gas sales price averaged $1.63/Mcf during the second quarter, a decrease of 22% compared to the first quarter of 2020. NYMEX benchmark prices fell 12% over the same period. The price weakness was mainly due to lower shoulder season demand as we transitioned from winter to spring. Additionally, an oversupply in the global LNG market has reduced North American LNG exports which effectively added more supply to North American natural gas markets. Our realized Marcellus sales price differential averaged US$0.49/Mcf below NYMEX during the quarter, compared to US$0.38/Mcf in the first quarter of 2020, reflecting seasonal weakness in local market price differentials over the period. Prices for Transco Zone 6 Non-New York averaged US$0.29/Mcf below NYMEX in the second quarter. By comparison, this market traded at a significant premium to NYMEX during the first quarter of 2020. This seasonal transition in localized Non-New York pricing resulted in weaker price realizations during the second quarter as expected. We continue to expect our Marcellus natural gas price differential to average US$0.45/Mcf below NYMEX in 2020.

FOREIGN EXCHANGE

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

The Canadian dollar weakened significantly during the first six months of 2020 in response to lower commodity prices as a result of the global excess supply of crude oil and the decreased demand impact of the COVID-19 pandemic. The USD/CDN exchange rate peaked at 1.45 USD/CDN in March and remained volatile throughout the second quarter of 2020, resulting in an average exchange rate of 1.37 USD/CDN during the first six months of 2020 compared to 1.33 USD/CDN for the same period in 2019. The Canadian dollar weakened to 1.36 USD/CDN at June 30, 2020, compared to 1.30 USD/CDN at December 31, 2019.

Price Risk Management

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

As of August 6, 2020, we have hedged 24,500 bbls/day of crude oil for the remainder of 2020, and 6,000 bbls/day for the first half of 2021. Our crude oil hedges are a mix of swaps, put spreads and three way collars in 2020, and strictly three way collars in 2021. The put spreads and three way collars provide us with exposure to significant upward price movement; however, the sold put effectively limits the amount of downside protection we have to the difference between the strike price of the purchased and sold puts. Overall, we expect our crude oil related hedging contracts to protect a significant portion of our cash flow from operating activities and adjusted funds flow.

The following is a summary of our financial contracts in place at August 6, 2020:

	WTI Crude Oil (US$/bbl)		
	Jul 1, 2020 – Sep 30, 2020	**Oct 1, 2020 – Dec 31, 2020**	**Jan 1, 2021 – Jun 30, 2021**
Swaps			
Volume (bbls/day)	7,000	—	—
Sold Swaps	$ 36.02	—	—
Put Spreads[1]			
Volume (bbls/day)	16,000	16,000	—
Sold Puts[2]	$ 46.88	$ 46.88	—
Purchased Puts	$ 57.50	$ 57.50	—
Three Way Collars[1]			
Volume (bbls/day)	5,000	5,000	6,000
Sold Puts	$ 48.00	$ 48.00	$ 32.00
Purchased Puts	$ 56.25	$ 56.25	$ 40.00
Sold Calls	$ 65.00	$ 65.00	$ 50.00

(1) The total average deferred premium spent on our outstanding hedges is US$1.75/bbl from July 1, 2020 to December 31, 2020 and US$0.03/bbl from January 1, 2021 to June 30, 2021.
(2) The sold puts on the put spreads settle annually at the end of 2020.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses) ($ millions)	**Three months ended June 30,** **2020**	**2019**	**Six months ended June 30,** **2020**	**2019**
Cash gains/(losses):				
Crude oil	$ 53.5	$ (5.9)	$ 86.5	$ (7.8)
Natural gas	—	4.7	—	17.2
Total cash gains/(losses)	$ 53.5	$ (1.2)	$ 86.5	$ 9.4
Non-cash gains/(losses):				
Crude oil	$ (64.4)	$ 23.6	$ 33.9	$ (63.3)
Natural gas	—	5.0	—	(3.5)
Total non-cash gains/(losses)	$ (64.4)	$ 28.6	$ 33.9	$ (66.8)
Total gains/(losses)	$ (10.9)	$ 27.4	$ 120.4	$ (57.4)

(Per BOE)	**Three months ended June 30,** **2020**	**2019**	**Six months ended June 30,** **2020**	**2019**
Total cash gains/(losses)	$ 6.73	$ (0.13)	$ 5.12	$ 0.55
Total non-cash gains/(losses)	(8.10)	3.12	2.01	(3.90)
Total gains/(losses)	$ (1.37)	$ 2.99	$ 7.13	$ (3.35)

We realized cash gains of $53.5 million and $86.5 million, respectively, on our crude oil contracts during the three and six months ended June 30, 2020, compared to realized cash losses of $5.9 million and $7.8 million, respectively, for the same periods in 2019. Cash gains recorded during the six months ended June 30, 2020 were primarily due to prices falling below the swap level as well as the net effect of benchmark prices below the put levels on both our put spreads and three way collars.

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, 2020, the fair value of crude oil contracts was in a net asset position of $44.0 million. For the three and six months ended June 30, 2020, the change in the fair value of our crude oil contracts resulted in a loss of $64.4 million and a gain of $33.9 million, respectively. Our natural gas contracts were settled in the fourth quarter of 2019 and there were no natural gas derivative contracts outstanding during the six months ended June 30, 2020.

Revenues

($ millions)	**Three months ended June 30,** **2020**	**2019**	**Six months ended June 30,** **2020**	**2019**
Oil and natural gas sales	$ 155.3	$ 403.2	$ 440.9	$ 759.6
Royalties	(33.2)	(81.7)	(90.7)	(150.7)
Oil and natural gas sales, net of royalties	$ 122.1	$ 321.5	$ 350.2	$ 608.9

Oil and natural gas sales, net of royalties, for the three and six months ended June 30, 2020 were $122.1 million and $350.2 million, respectively, a decrease of 62% and 42% from the same periods in 2019. The decrease in revenue was due to a reduction in realized prices as a result of demand destruction from the COVID-19 pandemic and the Saudi Arabia and Russian price war, along with lower production volumes due to price related curtailments on a portion of our crude oil and natural gas liquids production during the second quarter of 2020. See Note 11 to the Interim Financial Statements for further detail.

Royalties and Production Taxes

($ millions, except per BOE amounts)	**Three months ended June 30,** **2020**	**2019**	**Six months ended June 30,** **2020**	**2019**
Royalties	$ 33.2	$ 81.7	$ 90.7	$ 150.7
Per BOE	$ 4.18	$ 8.92	$ 5.37	$ 8.79
Production taxes	$ 7.7	$ 21.4	$ 23.1	$ 36.1
Per BOE	$ 0.97	$ 2.34	$ 1.37	$ 2.11
Royalties and production taxes	$ 40.9	$ 103.1	$ 113.8	$ 186.8
Per BOE	$ 5.15	$ 11.26	$ 6.74	$ 10.90
Royalties and production taxes (% of oil and natural gas sales)	26%	26%	26%	25%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees and freehold mineral taxes. A large percentage of our production is from U.S. properties where royalty rates are generally higher than in Canada and less sensitive to commodity price levels. Royalties and production taxes for the three and six months ended June 30, 2020 were $40.9 million and $113.8 million, respectively, a decrease of 60% and 39%, respectively, from the same periods in 2019. The decrease was primarily due to lower realized prices, and a decrease in production volumes.

We expect annual royalties and production taxes in 2020 to average 26% of oil and natural gas sales before transportation.

Operating Expenses

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	**2020**	**2019**	**2020**	**2019**
Cash operating expenses	$ 54.4	$ 71.8	$ 133.4	$ 141.6
Per BOE	$ 6.84	$ 7.84	$ 7.90	$ 8.26

For the three and six months ended June 30, 2020, operating expenses were $54.4 million or $6.84/BOE and $133.4 million or $7.90/BOE, respectively, a decrease of $17.4 million or $1.00/BOE and $8.2 million or $0.36/BOE, respectively, from the same periods in 2019. The decrease was primarily due to the price-related production curtailment of our highest unit expense crude oil wells, along with less well servicing activity and lower service costs compared to the same periods in 2019.

We continue to expect average annual operating costs of $8.25/BOE for 2020.

Transportation Costs

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	**2020**	**2019**	**2020**	**2019**
Transportation costs	$ 34.0	$ 36.8	$ 69.3	$ 68.1
Per BOE	$ 4.28	$ 4.02	$ 4.11	$ 3.97

For the three and six months ended June 30, 2020, transportation costs were $34.0 million or $4.28/BOE and $69.3 million or $4.11/BOE, respectively, compared to $36.8 million or $4.02/BOE and $68.1 million or $3.97/BOE, respectively, for the same periods in 2019. Transportation costs decreased during the second quarter due to lower production volumes as a result of price related production curtailments. The increase on a per BOE basis was primarily due to the impact of a weaker Canadian dollar on our U.S. dollar denominated transportation costs compared to the same periods in 2019.

We expect annual transportation costs to average $4.15/BOE for 2020.

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, 2020		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	52,198 BOE/day	210,971 Mcfe/day	87,360 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 25.63	$ 1.75	$ 19.53
Royalties and production taxes	(7.18)	(0.35)	(5.15)
Cash operating expenses	(10.45)	(0.25)	(6.84)
Transportation costs	(3.21)	(0.98)	(4.28)
Netback before hedging	$ 4.79	$ 0.17	$ 3.26
Cash hedging gains/(losses)	11.26	—	6.73
Netback after hedging	$ 16.05	$ 0.17	$ 9.99
Netback before hedging ($ millions)	$ 22.7	$ 3.3	$ 26.0
Netback after hedging ($ millions)	$ 76.2	$ 3.3	$ 79.5

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

Netbacks by Property Type	Three months ended June 30, 2019 Crude Oil	Natural Gas	Total
Average Daily Production	56,602 BOE/day	264,554 Mcfe/day	100,694 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 65.29	$ 2.78	$ 44.00
Royalties and production taxes	(17.51)	(0.54)	(11.26)
Cash operating expenses	(12.54)	(0.30)	(7.84)
Transportation costs	(3.02)	(0.88)	(4.02)
Netback before hedging	$ 32.22	$ 1.06	$ 20.88
Cash hedging gains/(losses)	(1.14)	0.19	(0.13)
Netback after hedging	$ 31.08	$ 1.25	$ 20.75
Netback before hedging ($ millions)	$ 166.0	$ 25.5	$ 191.5
Netback after hedging ($ millions)	$ 160.1	$ 30.2	$ 190.3

Netbacks by Property Type	Six months ended June 30, 2020 Crude Oil	Natural Gas	Total
Average Daily Production	55,716 BOE/day	222,410 Mcfe/day	92,784 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 35.63	$ 1.96	$ 26.11
Royalties and production taxes	(9.71)	(0.38)	(6.74)
Cash operating expenses	(11.99)	(0.29)	(7.90)
Transportation costs	(3.05)	(0.95)	(4.11)
Netback before hedging	$ 10.88	$ 0.34	$ 7.36
Cash hedging gains/(losses)	8.53	—	5.12
Netback after hedging	$ 19.41	$ 0.34	$ 12.48
Netback before hedging ($ millions)	$ 110.4	$ 14.0	$ 124.4
Netback after hedging ($ millions)	$ 196.9	$ 14.0	$ 210.9

Netbacks by Property Type	Six months ended June 30, 2019 Crude Oil	Natural Gas	Total
Average Daily Production	52,767 BOE/day	251,426 Mcfe/day	94,671 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 62.64	$ 3.55	$ 44.33
Royalties and production taxes	(16.32)	(0.68)	(10.90)
Cash operating expenses	(13.19)	(0.34)	(8.26)
Transportation costs	(2.90)	(0.89)	(3.97)
Netback before hedging	$ 30.23	$ 1.64	$ 21.20
Cash hedging gains/(losses)	(0.82)	0.38	0.55
Netback after hedging	$ 29.41	$ 2.02	$ 21.75
Netback before hedging ($ millions)	$ 288.6	$ 74.5	$ 363.1
Netback after hedging ($ millions)	$ 280.8	$ 91.7	$ 372.5

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

Our netbacks in 2020 were impacted by the low commodity price environment. Total netbacks before hedging decreased 86% and 66% during the three and six months ended June 30, 2020, respectively, compared to the same periods in 2019. Our price risk management program continues to provide funds flow protection, with realized cash gains on our crude oil hedging derivatives partially offsetting the impact of lower realized prices and improving total netbacks after hedging.

For the three and six months ended June 30, 2020, our crude oil properties accounted for 87% and 89% of our total netback before hedging, respectively, compared to 87% and 79% during the same periods in 2019.

General and Administrative ("G&A") Expenses

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

($ millions)	Three months ended June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
Cash:				
G&A expense	$ 9.1	$ 11.5	$ 21.5	$ 23.9
Share-based compensation expense	1.2	(0.6)	(1.6)	0.7
Non-Cash:				
Share-based compensation expense	3.6	4.3	11.3	12.3
Equity swap loss/(gain)	(0.5)	0.2	1.4	0.1
G&A expense	0.1	0.3	0.1	0.4
Total G&A expenses	$ 13.5	$ 15.7	$ 32.7	$ 37.4

(Per BOE)	Three months ended June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
Cash:				
G&A expense	$ 1.14	$ 1.26	$ 1.26	$ 1.39
Share-based compensation expense	0.15	(0.07)	(0.09)	0.04
Non-Cash:				
Share-based compensation expense	0.45	0.47	0.67	0.72
Equity swap loss/(gain)	(0.06)	0.03	0.08	0.01
G&A expense	0.01	0.03	0.01	0.02
Total G&A expenses	$ 1.69	$ 1.72	$ 1.93	$ 2.18

Cash G&A expenses for the three and six months ended June 30, 2020 were $9.1 million or $1.14/BOE and $21.5 million or $1.26/BOE, respectively, compared to $11.5 million or $1.26/BOE and $23.9 million or $1.39/BOE for the same periods in 2019. Cash G&A expenses were lower in part due to government funding received under the Canadian Emergency Wage Subsidy ("CEWS") program, which reimbursed qualifying Canadian employers for a portion of salaries paid during the six months ended June 30, 2020. Cash G&A expenses during the second quarter were further lowered by cash compensation reductions for our Board of Directors, executives and employees and other non-salary cost saving initiatives.

During the second quarter of 2020, we reported a cash SBC expense of $1.2 million due to the impact of an increase in our share price on outstanding deferred share units. In comparison, during the same period of 2019, we recorded a cash SBC recovery of $0.6 million as a result of a decrease in our share price. We recorded non-cash SBC expense of $3.6 million or $0.45/BOE, a decrease from an expense of $4.3 million, or $0.47/BOE, during the same period in 2019.

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. In the second quarter of 2020, we recorded a mark-to-market gain of $0.5 million on these contracts, compared to a loss of $0.2 million in the same period in 2019.

Based on cash G&A cost reductions and estimated government funding, we expect annual cash G&A expenses to average approximately $1.40/BOE for 2020*.*

Interest Expense

For the three and six months ended June 30, 2020, we recorded total interest expense of $7.1 million and $16.0 million, respectively, compared to $8.7 million and $17.1 million for the same periods in 2019. The decrease in interest expense in the second quarter of 2020 was primarily due to the repayment of a portion of our 2009 and 2012 senior notes.

At June 30, 2020, our debt balance consisted primarily of fixed interest rate senior notes, with a weighted average interest rate of 4.6%. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Realized foreign exchange (gain)/loss:				
Foreign exchange (gain)/loss on settlements	$ 0.1	$ 0.1	$ —	$ —
Translation of U.S. dollar cash held in Canada (gain)/loss	0.4	4.1	(2.7)	9.3
Unrealized foreign exchange (gain)/loss	1.0	(16.5)	(1.4)	(33.6)
Total foreign exchange (gain)/loss	$ 1.5	$ (12.3)	$ (4.1)	$ (24.3)
USD/CDN average exchange rate	1.39	1.34	1.37	1.33
USD/CDN period end exchange rate	1.36	1.31	1.36	1.31

For the three and six months ended June 30, 2020, we recorded a foreign exchange loss of $1.5 million and a foreign exchange gain of $4.1 million, respectively, compared to gains of $12.3 million and $24.3 million for the same periods in 2019. Realized foreign exchange gains and losses relate primarily to day-to-day transactions recorded in foreign currencies along with the translation of our U.S. dollar denominated cash held in Canada, while unrealized foreign exchange gains and losses are recorded on the translation of our U.S dollar denominated bank debt and working capital held in Canada at each period end.

Effective January 1, 2020, we have designated our outstanding senior notes as a net investment hedge related to our U.S. operations. As a result of the adoption of net investment hedge accounting, any unrealized foreign exchange gains and losses on the translation of this U.S. dollar denominated debt are included in Other Comprehensive Income/(Loss). At June 30, 2020, US$385.4 million of senior notes outstanding were designated as a net investment hedge. For the three and six months ended June 30, 2020, Other Comprehensive Income/(Loss) included an unrealized gain of $19.5 million and a loss of $30.6 million respectively, on our outstanding U.S. dollar denominated senior notes. See Note 3(a) to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Capital spending(1)	$ 40.1	$ 207.2	$ 203.7	$ 368.0
Office capital(1)	0.9	2.1	2.8	3.3
Line fill	—	—	—	5.1
Sub-total	41.0	209.3	206.5	376.4
Property and land acquisitions	$ 3.4	$ 1.9	$ 5.7	$ 4.9
Property divestments	0.1	(9.6)	(5.5)	(10.1)
Sub-total	3.5	(7.7)	0.2	(5.2)
Total	$ 44.5	$ 201.6	$ 206.7	$ 371.2

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

Capital spending for the three and six months ended June 30, 2020, decreased to $40.1 million and $203.7 million, respectively, compared to $207.2 million and $368.0 million for the same periods in 2019. The decrease was mainly due to the suspension of operated drilling and completions activity in North Dakota during the second quarter of 2020. Capital spending during the second quarter included $31.4 million on our U.S. crude oil properties, $5.8 million on our Marcellus natural gas assets and $3.1 million on our Canadian waterflood properties.

During the second quarter of 2020, we completed $3.4 million in property and land acquisitions, which included minor acquisitions of leases and undeveloped land, compared to $1.9 million for the same period in 2019. We completed a nominal amount of property divestments for the three months ended June 30, 2020, compared to $9.6 million for the same period in 2019, which related to the divestment of properties in Southeastern Saskatchewan.

We are maintaining our capital spending target of $300 million. Remaining activity is primarily focused on non-operated drilling and completions in the Marcellus and North Dakota, with four operated completions in North Dakota in the fourth quarter. In total, we expect to complete approximately six net wells (operated and non-operated) in North Dakota and two net wells in the Marcellus in the second half of 2020.

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

($ millions, except per BOE amounts)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
DD&A expense	$ 79.9	$ 88.3	$ 175.1	$ 164.2
Per BOE	$ 10.05	$ 9.64	$ 10.37	$ 9.58

DD&A of PP&E is recognized using the unit-of-production method based on proved reserves. For the three months ended June 30, 2020, DD&A expense decreased to $79.9 million, compared to $88.3 million in the same period of 2019 as a result of lower overall production volumes. DD&A expense on a per BOE basis increased over the same period as a result of previous capital activity increasing the depletable base.

For the six months ended June 30, 2020, DD&A expense increased to $175.1 million, compared to $164.2 million in the same period of 2019, due to an increase in U.S. crude oil production with higher depletion rates and the impact of a weaker Canadian dollar.

Impairment

PP&E

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves using SEC constant prices ("Standardized Measure"). SEC prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. The Standardized Measure is not related to Enerplus' investment criteria and is not a fair value based measurement, but rather a prescribed accounting calculation. Impairments are non-cash and are not reversed in future periods under U.S. GAAP. See Note 6(a) to the Interim Financial Statements for trailing twelve month prices.

Trailing twelve month average crude oil and natural gas prices have been declining throughout the first half of 2020. For the three and six months ended June 30, 2020, we recorded a non-cash PP&E impairment of $426.8 million (Canadian cost centre: $77.5 million, U.S. cost centre: $349.3 million). There were no impairments recorded for the same periods in 2019.

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. For the remainder of 2020, the primary factors include future first-day-of-the-month commodity prices, reserves revisions, capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. If commodity prices remain at current levels, the twelve month trailing prices will decline further, impacting the ceiling value and resulting in an increased risk of future PP&E impairments. See "Risk Factors and Risk Management - Risk of Impairment of Oil and Gas Properties, Deferred Tax Assets and Goodwill" in the Annual MD&A and "Risk Factors and Risk Management" in this MD&A.

Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

Goodwill is assessed for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus first performs a qualitative assessment to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to the reporting unit's fair value, with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss). The loss recognized should not exceed the total amount of goodwill allocated to that reporting unit.

During the second quarter of 2020, we recorded a non-cash goodwill impairment charge of $202.8 million related to our U.S. reporting unit. The impairment was a result of the ongoing deterioration in macroeconomic conditions and low commodity prices due to the COVID-19 pandemic, which resulted in a reduction in the fair value of the U.S. reporting unit and a full write down of our U.S. goodwill asset. There was no goodwill impairment during the same period of the prior year. In the fourth quarter of 2019, we recorded a goodwill impairment of $451.1 million representing the full value of the goodwill attributable to our Canadian reporting unit. At June 30, 2020, there was no goodwill remaining on our Condensed Consolidated Balance Sheet.

Asset Retirement Obligation

In connection with our operations, we incur abandonment, reclamation and remediation costs related to assets, such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on the Condensed Consolidated Balance Sheet are based on management's estimate of our net ownership interest, costs to abandon, reclaim and remediate and the timing of the costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation, using a weighted average credit-adjusted risk-free rate of 5.35%, to be $146.2 million at June 30, 2020, compared to $138.0 million at December 31, 2019, using a weighted average credit-adjusted risk-free rate of 5.50%. For the three and six months ended June 30, 2020, asset retirement obligation settlements were $0.3 million and $11.1 million, respectively, compared to $0.5 million and $5.9 million during the same periods in 2019. See Note 9 to the Interim Financial Statements for further details.

Leases

Enerplus recognizes right-of-use ("ROU") assets and lease liabilities on the Condensed Consolidated Balance Sheet for qualifying leases with a term greater than 12 months. We incur lease payments related to office space, drilling rig commitments, vehicles and other equipment. Total lease liabilities are based on the present value of lease payments over the lease term. Total ROU assets represent our right to use an underlying asset for the lease term. At June 30, 2020, our total lease liability was $43.6 million. In addition, ROU assets of $39.1 million were recorded, which equate to our lease liabilities less lease incentives. See Note 10 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2020	2019	2020	2019
Current tax expense/(recovery)	$ (14.4)	$ (13.9)	$ (14.4)	$ (19.5)
Deferred tax expense/(recovery)	(98.9)	48.8	10.4	30.9
Total tax expense/(recovery)	$ (113.3)	$ 34.9	$ (4.0)	$ 11.4

For the three and six months ended June 30, 2020, we recorded a current tax recovery of $14.4 million, compared to a recovery of $13.9 and $19.5 million, respectively, for the same periods in 2019. The recovery in the second quarter of 2020 relates to the recognition of our final U.S. Alternative Minimum Tax ("AMT") refund.

For the three and six months ended June 30, 2020, we recorded a deferred income tax recovery of $98.9 million and an expense of $10.4 million respectively, compared to an expense of $48.8 million and $30.9 million, for the same periods in 2019. The deferred tax recovery in the second quarter was primarily due to lower net income and non-cash PP&E impairments recorded in both Canada and the U.S.

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 reserves at forecast average prices and costs. For the six months ended June 30, 2020, a valuation allowance of $93.6 million was recorded during the first quarter of 2020 related entirely to our Canadian deferred income tax assets. No valuation allowance was recorded for the six months ended June 30, 2019. Our overall net deferred income tax asset was $367.3 million at June 30, 2020 (December 31, 2019 - $372.5 million).

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess liquidity and leverage, including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging, share repurchases and dividend levels. We also assess our leverage relative to our most restrictive debt covenant under our bank credit facility and senior notes, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At June 30, 2020, our senior debt to adjusted EBITDA ratio was 1.0x and our net debt to adjusted funds flow ratio was 1.0x. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate liquidity.

At June 30, 2020, we had $6.2 million of cash on hand. Total debt net of cash at June 30, 2020, was $518.1 million, an increase of 14% compared to $455.0 million at December 31, 2019. The increase when compared to December 31, 2019 was primarily due to the impact of a weaker Canadian dollar on our U.S. dollar denominated debt and a decrease in cash from $151.6 million at December 31, 2019. During the second quarter, we made scheduled principal repayments of US$81.6 million on our 2009 and 2012 senior notes using our cash on hand, which resulted in a $114.0 million decrease to our outstanding senior notes at June 30, 2020, compared to December 31, 2019.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 68% and 120% for the three and six months ended June 30, 2020 respectively, compared to 116% and 110% for the same periods in 2019.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, increased to $217.6 million at June 30, 2020, from $210.4 million at December 31, 2019. We expect to finance our working capital deficit and our ongoing working capital requirements through cash on hand, cash flow from operations and our bank credit facility. We continue to expect to be able to meet our financial commitments, as disclosed under “Commitments” in the Annual MD&A.

During the first quarter of 2020, we repurchased and cancelled 340,434 common shares for total consideration of $2.5 million under our Normal Course Issuer Bid (“NCIB”), prior to its expiry on March 25, 2020. Given the current environment, we chose not to renew our NCIB in order to preserve capital and maintain our balance sheet strength and liquidity. We plan to renew our NCIB in due course and recommence our share repurchase program when market conditions improve.

At June 30, 2020, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. We expect to manage our business within these financial ratios during 2020. 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 and "Risk Factors and Risk Management" in this MD&A. Our bank credit facility and senior note purchase agreements have been filed under our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at June 30, 2020:

Covenant Description		June 30, 2020
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	1.0x
Total debt to adjusted EBITDA (1)	4.0x	1.0x
Total debt to capitalization	55%	22%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	1.0x
Senior debt to consolidated present value of total proved reserves(3)	60%	17%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	16.6x

Definitions
“Senior debt” is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.
“Adjusted EBITDA” is calculated as net income less interest, taxes, depletion, depreciation, amortization, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended June 30, 2020 was $62.2 million and $545.1 million, respectively.
“Total debt” is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.
“Capitalization” is calculated as the sum of total debt and shareholder’s equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

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

Dividends

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per share amounts)	2020	2019	2020	2019
Dividends to shareholders(1)	$ 6.7	$ 7.0	$ 13.3	$ 14.2
Per weighted average share (Basic)	$ 0.03	$ 0.03	$ 0.06	$ 0.06

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

During the three and six months ended June 30, 2020, we reported total dividends of $6.7 million or $0.03 per share and $13.3 million or $0.06 per share, respectively, compared to $7.0 million or $0.03 per share and $14.2 million or $0.06 per share for the same periods in 2019. Dividends to shareholders have decreased compared to the same period in 2019 as a result of our share repurchase program.

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

Shareholders' Capital

	Six months ended June 30, 2020	2019
Share capital ($ millions)	$ 3,097.0	$ 3,225.6
Common shares outstanding (thousands)	222,548	231,616
Weighted average shares outstanding – basic (thousands)	222,457	237,197
Weighted average shares outstanding – diluted (thousands)	222,457	239,947

For the six months ended June 30, 2020, a total of 2,044,718 units vested pursuant to our treasury settled LTI plans, including the impact of performance multipliers (2019 – 1,007,234). In total, 1,160,000 shares were issued from treasury and $13.8 million was transferred from paid-in capital to share capital (2019 – 564,000; $4.4 million). We elected to cash settle the remaining units related to the required tax withholdings (2020 – $7.2 million, 2019 – $5.0 million).

During the six months ended June 30, 2020, the Company repurchased 340,434 common shares under the previous NCIB at an average price of $7.44 per share, for total consideration of $2.5 million (2019 – 8,358,821; $90.4 million). Of the amount paid, $4.7 million was charged to share capital and $2.2 million was credited to accumulated deficit (2019 – $116.4 million; $26.0 million). There were no share repurchases during the three months ended June 30, 2020, as we chose not to renew our NCIB after its expiry on March 25, 2020, in order to preserve capital and maintain our balance sheet strength and liquidity.

At August 6, 2020, we had 222,547,600 common shares outstanding. In addition, an aggregate of 6,960,901 common shares may be issued to settle outstanding grants under the Performance Share Unit ("PSU") and Restricted Share Unit plans assuming the maximum performance multiplier of 2.0 times for the PSUs.

For further details, see Note 15 to the Interim Financial Statements.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended June 30, 2020			Three months ended June 30, 2019		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	6,066	37,102	43,168	8,749	39,392	48,141
Natural gas liquids (bbls/day)	613	4,316	4,929	931	3,789	4,720
Natural gas (Mcf/day)	12,315	223,264	235,579	23,120	263,880	287,000
Total average daily production (BOE/day)	8,731	78,629	87,360	13,533	87,161	100,694
Pricing(2)						
Crude oil (per bbl)	$ 19.57	$ 32.35	$ 30.55	$ 67.12	$ 76.04	$ 74.42
Natural gas liquids (per bbl)	15.17	(3.25)	(0.96)	25.31	16.16	17.96
Natural gas (per Mcf)	2.19	1.60	1.63	1.82	2.71	2.63
Capital Expenditures						
Capital spending	$ 2.9	$ 37.2	$ 40.1	$ 7.0	$ 200.2	$ 207.2
Acquisitions	0.4	3.0	3.4	1.1	0.8	1.9
Divestments	0.1	—	0.1	(9.4)	(0.2)	(9.6)
Netback(3) Before Hedging						
Oil and natural gas sales	$ 14.7	$ 140.6	$ 155.3	$ 60.1	$ 343.1	$ 403.2
Royalties	(1.7)	(31.5)	(33.2)	(12.7)	(69.0)	(81.7)
Production taxes	0.1	(7.8)	(7.7)	(0.2)	(21.2)	(21.4)
Cash operating expenses	(11.3)	(43.1)	(54.4)	(17.5)	(54.3)	(71.8)
Transportation costs	(1.7)	(32.3)	(34.0)	(2.6)	(34.2)	(36.8)
Netback before hedging	$ 0.1	$ 25.9	$ 26.0	$ 27.1	$ 164.4	$ 191.5
Other Expenses						
Asset impairment	$ 77.5	$ 349.3	$ 426.8	$ —	$ —	$ —
Goodwill impairment	—	202.8	202.8	—	—	—
Commodity derivative instruments loss/(gain)	10.9	—	10.9	(27.4)	—	(27.4)
Total G&A(4)	(0.4)	13.9	13.5	(1.9)	17.6	15.7
Current income tax expense/(recovery)	—	(14.4)	(14.4)	(13.9)	—	(13.9)

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

($ millions, except per unit amounts)	Six months ended June 30, 2020 Canada	U.S.	Total	Six months ended June 30, 2019 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	6,951	39,155	46,106	8,873	35,769	44,642
Natural gas liquids (bbls/day)	661	4,476	5,137	957	3,595	4,552
Natural gas (Mcf/day)	13,614	235,632	249,246	23,730	249,133	272,863
Total average daily production (BOE/day)	9,881	82,903	92,784	13,785	80,886	94,671
Pricing[2]						
Crude oil (per bbl)	$ 30.40	$ 43.57	$ 41.59	$ 63.06	$ 72.75	$ 70.82
Natural gas liquids (per bbl)	19.85	4.13	6.16	30.71	15.29	18.53
Natural gas (per Mcf)	2.18	1.85	1.87	3.26	3.48	3.46
Capital Expenditures						
Capital spending	$ 14.7	$ 189.0	$ 203.7	$ 24.5	$ 343.5	$ 368.0
Acquisitions	1.5	4.2	5.7	2.1	2.8	4.9
Divestments	0.1	(5.6)	(5.5)	(9.5)	(0.6)	(10.1)
Netback[3] **Before Hedging**						
Oil and natural gas sales	$ 47.5	$ 393.4	$ 440.9	$ 121.9	$ 637.7	$ 759.6
Royalties	(7.4)	(83.3)	(90.7)	(21.7)	(129.0)	(150.7)
Production taxes	(0.2)	(22.9)	(23.1)	(0.9)	(35.2)	(36.1)
Cash operating expenses	(28.9)	(104.5)	(133.4)	(38.4)	(103.2)	(141.6)
Transportation costs	(3.8)	(65.5)	(69.3)	(5.3)	(62.8)	(68.1)
Netback before hedging	$ 7.2	$ 117.2	$ 124.4	$ 55.6	$ 307.5	$ 363.1
Other Expenses						
Asset impairment	$ 77.5	$ 349.3	$ 426.8	$ —	$ —	$ —
Goodwill impairment	—	202.8	202.8	—	—	—
Commodity derivative instruments loss/(gain)	(120.4)	—	(120.4)	57.4	—	57.4
Total G&A[4]	(0.6)	33.3	32.7	11.3	26.1	37.4
Current income tax expense/(recovery)	—	(14.4)	(14.4)	(14.0)	(5.5)	(19.5)

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

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Diluted
2020				
Second Quarter	$ 122.1	$ (609.3)	$ (2.74)	$ (2.74)
First Quarter	228.1	2.9	0.01	0.01
Total 2020	$ 350.2	$ (606.4)	$ (2.73)	$ (2.73)
2019				
Fourth Quarter	$ 327.0	$ (429.1)	$ (1.93)	$ (1.93)
Third Quarter	318.9	65.1	0.28	0.28
Second Quarter	321.4	85.1	0.36	0.36
First Quarter	287.5	19.2	0.08	0.08
Total 2019	$ 1,254.8	$ (259.7)	$ (1.12)	$ (1.12)
2018				
Fourth Quarter	$ 326.7	$ 249.4	$ 1.03	$ 1.02
Third Quarter	373.6	86.9	0.35	0.35
Second Quarter	327.4	12.4	0.05	0.05
First Quarter	265.0	29.6	0.12	0.12
Total 2018	$ 1,292.7	$ 378.3	$ 1.55	$ 1.53

Oil and natural gas sales, net of royalties, decreased to $122.1 million during the second quarter of 2020 compared to $228.1 million in the first quarter of 2020 due to lower realized prices and price related production curtailments. We reported a net loss of $609.3 million during the second quarter of 2020 compared to net income of $2.9 million in the first quarter of 2020. In addition to a decrease in oil and natural gas sales revenue, net loss in the second quarter was impacted by non-cash impairments, including a $426.8 million impairment on our PP&E, a $202.8 million impairment of our U.S. goodwill asset, and a $162.7 million decrease in the fair value of our commodity derivative instruments compared to the first quarter of 2020.

Oil and natural gas sales, net of royalties, in 2019 were essentially flat when compared to 2018 due to lower realized commodity prices, offset by increased production. We reported a net loss in 2019 due to a non-cash impairment of $451.1 million on our Canadian goodwill asset recorded in the fourth quarter and a loss on commodity derivative instruments of $66.1 million compared to a gain of $88.2 million recorded in 2018.

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. As at June 30, 2020, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

RISK FACTORS AND RISK MANAGEMENT

Risks Relating to the Impact of the COVID-19 Pandemic and Continued Weakness and Volatility in Commodity Prices

The global outbreak of the COVID-19 pandemic and the ongoing uncertainty as to the extent and duration of this pandemic, as well as governmental authorities response thereto, has resulted in, and may continue to result in, among other things: increased volatility in financial markets, including credit markets and foreign currency and interest exchange rates; disruptions to global supply chains; labour shortages; reductions in trade volumes; temporary operational restrictions, quarantine orders, business closures and travel bans; an overall slowdown in the global economy; political and economic instability; and civil unrest. In particular, the COVID-19 pandemic has resulted in, and may continue to result in, a reduction in the demand for crude oil and natural gas.

In addition, recent market events and conditions, including excess global crude oil and natural gas supply and decreased global demand due to the COVID-19 pandemic, have caused significant weakness and volatility in commodity prices. While the commodity prices began to stabilize as global economies began to re-open in June, the recent resurgence of COVID-19 cases in certain geographic areas, and the possibility that a resurgence may occur in other areas, has resulted in the re-imposition of certain restrictions noted above by local authorities. This further increases the risk and uncertainty as to the extent and duration of the COVID-19 pandemic and the resultant impact on commodity demand and prices. The overall result of these recent events and conditions could lead to a prolonged period of depressed prices for crude oil and natural gas which may result in further curtailments, voluntary or otherwise. We are continuing to evaluate the impact of the COVID-19 pandemic and the continued commodity environment instability on our business, financial condition and results of operations; however, the full extent of such impact continues to be unknown at this time and will depend on future developments (which are highly uncertain and cannot be predicted with any degree of confidence) and may be adverse and could result, among other things, in PP&E or deferred tax asset impairment, or exceeding our debt covenants, among others. See disclosure under "Impairment – PP&E", “Income Taxes” and "Liquidity and Capital Resources" in this MD&A.

We are also subject to risks relating to the health and safety of our personnel, including the potential for a slowdown or temporary suspension of our operations in locations impacted by an outbreak or further regulatory changes. Such a suspension in operations could also be mandated by governmental authorities in response to the COVID-19 pandemic. This would negatively impact our production volumes, which could adversely impact our business, financial condition and results of operations.

Depending on the extent and duration of the COVID-19 pandemic, it may also have the effect of heightening many of the other risks described in the Annual Information Form and the Annual MD&A.

2020 GUIDANCE

Summary of 2020 Expectations	Target
Capital spending	$300 million
Average annual production	88,000 - 90,000 BOE/day
Average annual crude oil and natural gas liquids production	49,000 - 50,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	26%
Operating expenses	$8.25/BOE
Transportation costs	$4.15/BOE
Cash G&A expenses	$1.40/BOE

2020 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(5.00)/bbl(2)
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.45)/Mcf

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

NON-GAAP MEASURES

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

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

Calculation of Netback	Three months ended June 30,		Six months ended June 30,	
($ millions)	2020	2019	2020	2019
Oil and natural gas sales	$ 155.3	$ 403.2	$ 440.9	$ 759.6
Less:				
Royalties	(33.2)	(81.7)	(90.7)	(150.7)
Production taxes	(7.7)	(21.4)	(23.1)	(36.1)
Cash operating expenses	(54.4)	(71.8)	(133.4)	(141.6)
Transportation costs	(34.0)	(36.8)	(69.3)	(68.1)
Netback before hedging	$ 26.0	$ 191.5	$ 124.4	$ 363.1
Cash gains/(losses) on derivative instruments	53.5	(1.2)	86.5	9.4
Netback after hedging	$ 79.5	$ 190.3	$ 210.9	$ 372.5

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

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	Three months ended June 30,		Six months ended June 30,	
($ millions)	2020	2019	2020	2019
Cash flow from operating activities	$ 90.6	$ 237.0	$ 213.3	$ 345.9
Asset retirement obligation expenditures	0.3	0.5	11.1	5.9
Changes in non-cash operating working capital	(20.9)	(51.5)	(41.2)	3.0
Adjusted funds flow	$ 70.0	$ 186.0	$ 183.2	$ 354.8

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

Calculation of Free Cash Flow	Three months ended June 30,		Six months ended June 30,	
($ millions)	2020	2019	2020	2019
Adjusted funds flow	$ 70.0	$ 186.0	$ 183.2	$ 354.8
Capital spending	(40.1)	(207.2)	(203.7)	(368.0)
Free cash flow	$ 29.9	$ (21.2)	$ (20.5)	$ (13.2)

"Adjusted net income/(loss)" is used by Enerplus and is useful to investors and securities analysts in evaluating the financial performance of the Company by understanding the impact of certain non-cash items and other items that the Company considers appropriate to adjust given the irregular nature and relevance to comparable companies. Adjusted net income/(loss) is calculated as net income/(loss) adjusted for unrealized derivative instrument gain/loss, asset impairment, unrealized foreign exchange gain/loss, the tax effect of these items, goodwill impairment, the impact of statutory changes to the Company's corporate tax rate, and the valuation allowance on our deferred income tax assets. There was no asset or goodwill impairments for the three and six months ended June 30, 2019.

Calculation of Adjusted Net Income/(Loss)	Three months ended June 30,		Six months ended June 30,	
($ millions)	2020	2019	2020	2019
Net income/(loss)	$ (609.3)	$ 85.1	$ (606.4)	$ 104.3
Unrealized derivative instrument (gain)/loss	63.9	(28.4)	(32.5)	67.0
Asset impairment	426.8	—	426.8	—
Unrealized foreign exchange (gain)/loss	1.0	(16.5)	(1.4)	(33.6)
Tax effect on above items	(126.4)	7.8	(103.0)	(17.1)
Goodwill impairment	202.8	—	202.8	—
Income tax rate adjustment on deferred taxes	—	26.3	—	26.3
Valuation allowance on deferred taxes	—	—	93.6	—
Adjusted net income/(loss)	$ (41.2)	$ 74.3	$ (20.1)	$ 146.9

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

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

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

Calculation of Adjusted Payout Ratio	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2020**	**2019**	**2020**	**2019**
Dividends	$ 6.7	$ 7.0	$ 13.3	$ 14.2
Capital, office expenditures and line fill	41.0	209.3	206.5	376.4
Sub-total	$ 47.7	$ 216.3	$ 219.8	$ 390.6
Adjusted funds flow	$ 70.0	$ 186.0	$ 183.2	$ 354.8
Adjusted payout ratio (%)	68%	116%	120%	110%

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

Reconciliation of Net Income/(Loss) to Adjusted EBITDA(1)	
($ millions)	**June 30, 2020**
Net income/(loss)	$ (970.4)
Add:	
Goodwill impairment	653.9
Interest	32.8
Current and deferred tax expense/(recovery)	32.4
DD&A and asset impairment	794.5
Other non-cash charges(2)	3.9
Adjusted EBITDA	$ 547.1

(1) Balances above at June 30, 2020 include the six months ended June 30, 2020 and the third and fourth quarter of 2019.
(2) Includes the change in fair value of commodity derivatives and equity swaps, non-cash SBC expense, non-cash G&A expense and unrealized foreign exchange gains/losses.

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

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a - 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at June 30, 2020, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on April 1, 2020 and ended June 30, 2020 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected capital spending levels in 2020 and impact thereof on our production levels and land holdings; expected production volumes; expected operating strategy in 2020, including the proportion of Enerplus' production that may be curtailed and the effect of such actions on its properties, operations and financial position; the proportion of our anticipated oil and gas production that is hedged and the expected effectiveness of such hedges in protecting our adjusted funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials, our commodity risk management program in 2020 and expected hedging gains; expectations regarding our realized oil and natural gas prices; expected operating, transportation and cash G&A costs; potential future non-cash PP&E impairments, as well as relevant factors that may affect such impairment; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes; Enerplus' costs reduction initiatives and the expected cost savings therefrom in 2020; and the amount of future cash dividends that we may pay to our shareholders.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure and/or low commodity price environment will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to comply with our debt covenants; the availability of third party services; and the extent of our liabilities. In addition, our expected 2020 capital expenditures and operating strategy described in this MD&A is based on the rest of the year prices and exchange rate of: a WTI price of US$41.19/bbl, a NYMEX price of US$1.94/Mcf, and a USD/CDN exchange rate of 1.35. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. Current conditions, economic and otherwise, render assumptions, although reasonable when made, subject to greater uncertainty.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued instability, or further deterioration, in global economic and market environment, including from COVID-19; continued low commodity prices environment or further decline and/or volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in this MD&A, our Annual Information Form, our Annual MD&A and Form 40-F as at December 31, 2019).

The forward-looking information contained in this MD&A speak 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.

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	June 30, 2020	December 31, 2019
Assets			
Current Assets			
Cash and cash equivalents		$ 6,177	$ 151,649
Accounts receivable	4	121,395	176,119
Income tax receivable	14	29,116	27,770
Derivative financial assets	16	46,186	10,570
Other current assets		3,190	2,990
		206,064	369,098
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	5	1,230,072	1,547,362
Other capital assets, net	5	20,746	20,244
Property, plant and equipment		1,250,818	1,567,606
Right-of-use assets	10	39,149	48,729
Goodwill	6	—	194,015
Deferred income tax asset	14	367,270	372,502
Income tax receivable	14	—	13,852
Total Assets		$ 1,863,301	$ 2,565,802
Liabilities			
Current liabilities			
Accounts payable	7	$ 244,929	$ 291,540
Dividends payable		2,225	2,217
Current portion of long-term debt	8	110,780	105,998
Derivative financial liabilities	16	5,851	2,734
Current portion of lease liabilities	10	13,410	17,541
		377,195	420,030
Long-term debt	8	413,491	500,635
Asset retirement obligation	9	146,171	138,049
Lease liabilities	10	30,228	35,530
		589,890	674,214
Total Liabilities		967,085	1,094,244
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: June 30, 2020 – 223 million shares			
December 31, 2019 – 222 million shares	15	3,096,969	3,088,094
Paid-in capital		48,758	59,490
Accumulated deficit		(2,601,744)	(1,984,365)
Accumulated other comprehensive income/(loss)		352,233	308,339
		896,216	1,471,558
Total Liabilities & Shareholders' Equity		$ 1,863,301	$ 2,565,802
Commitments and Contingencies	17		

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)

(CDN$ thousands, except per share amounts) unaudited	Note	Three months ended June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
Revenues					
Oil and natural gas sales, net of royalties	11	$ 122,069	$ 321,463	$ 350,196	$ 608,915
Commodity derivative instruments gain/(loss)	16	(10,895)	27,422	120,446	(57,445)
		111,174	348,885	470,642	551,470
Expenses					
Operating		54,353	71,818	133,373	141,611
Transportation		34,006	36,803	69,335	68,094
Production taxes		7,687	21,442	23,131	36,057
General and administrative	12	13,494	15,680	32,679	37,390
Depletion, depreciation and accretion		79,885	88,315	175,077	164,226
Asset impairment	6	426,810	—	426,810	—
Goodwill impairment	6	202,767	—	202,767	—
Interest		7,051	8,693	15,962	17,086
Foreign exchange (gain)/loss	13	1,493	(12,251)	(4,144)	(24,277)
Other expense/(income)		6,301	(1,568)	6,072	(4,430)
		833,847	228,932	1,081,062	435,757
Income/(Loss) before taxes		(722,673)	119,953	(610,420)	115,713
Current income tax expense/(recovery)	14	(14,422)	(13,928)	(14,395)	(19,458)
Deferred income tax expense/(recovery)	14	(98,928)	48,797	10,422	30,929
Net Income/(Loss)		$ (609,323)	$ 85,084	$ (606,447)	$ 104,242
Other Comprehensive Income/(Loss)					
Unrealized gain/(loss) on foreign currency translation		(57,284)	(34,208)	74,490	(70,564)
Foreign exchange gain/(loss) on net investment hedge with U.S. denominated debt	3,16	19,466	—	(30,596)	—
Total Comprehensive Income/(Loss)		$ (647,141)	$ 50,876	$ (562,553)	$ 33,678
Net income/(Loss) per share					
Basic	15	$ (2.74)	$ 0.36	$ (2.73)	$ 0.44
Diluted	15	$ (2.74)	$ 0.36	$ (2.73)	$ 0.43

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

Condensed Consolidated Statements of Changes in Shareholders' Equity

(CDN$ thousands) unaudited	Three months ended June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
Share Capital				
Balance, beginning of period	$ 3,097,187	$ 3,317,855	$ 3,088,094	$ 3,337,608
Purchase of common shares under Normal Course Issuer Bid	—	(92,264)	(4,731)	(116,423)
Share-based compensation – treasury settled	—	—	13,824	4,406
Cancellation of predecessor shares	(218)	—	(218)	—
Balance, end of period	$ 3,096,969	$ 3,225,591	$ 3,096,969	$ 3,225,591
Paid-in Capital				
Balance, beginning of period	$ 44,430	$ 45,209	$ 59,490	$ 46,524
Share-based compensation – cash settled (tax withholding)	—	—	(7,232)	(4,952)
Share-based compensation – treasury settled	—	—	(13,824)	(4,406)
Share-based compensation – non-cash	4,328	4,263	10,324	12,306
Balance, end of period	$ 48,758	$ 49,472	$ 48,758	$ 49,472
Accumulated Deficit				
Balance, beginning of period	$ (1,985,964)	$ (1,755,757)	$ (1,984,365)	$ (1,772,084)
Purchase of common shares under Normal Course Issuer Bid	—	21,708	2,195	26,039
Net income/(loss)	(609,323)	85,084	(606,447)	104,242
Cancellation of predecessor shares	218	—	218	—
Dividends declared ($0.01 per share)	(6,675)	(7,034)	(13,345)	(14,196)
Balance, end of period	$ (2,601,744)	$ (1,655,999)	$ (2,601,744)	$ (1,655,999)
Accumulated Other Comprehensive Income/(Loss)				
Balance, beginning of period	$ 390,051	$ 352,585	$ 308,339	$ 388,941
Unrealized gain/(loss) on foreign currency translation	(57,284)	(34,208)	74,490	(70,564)
Foreign exchange gain/(loss) on net investment hedge with U.S. denominated debt	19,466	—	(30,596)	—
Balance, end of period	$ 352,233	$ 318,377	$ 352,233	$ 318,377
Total Shareholders' Equity	$ 896,216	$ 1,937,441	$ 896,216	$ 1,937,441

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

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Note	Three months ended June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
Operating Activities					
Net income/(loss)		$ (609,323)	$ 85,084	$ (606,447)	$ 104,242
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		79,885	88,315	175,077	164,226
Asset impairment	6	426,810	—	426,810	—
Goodwill impairment	6	202,767	—	202,767	—
Changes in fair value of derivative instruments	16	63,929	(28,353)	(32,499)	66,975
Deferred income tax expense/(recovery)	14	(98,928)	48,797	10,422	30,929
Foreign exchange (gain)/loss on debt and working capital	13,16	1,038	(16,498)	(1,377)	(33,602)
Share-based compensation and general and administrative	12,15	3,428	4,535	11,183	12,669
Translation of U.S. dollar cash held in Canada	13	391	4,158	(2,712)	9,354
Asset retirement obligation expenditures	9	(333)	(503)	(11,127)	(5,893)
Changes in non-cash operating working capital	18	20,896	51,456	41,202	(2,958)
Cash flow from/(used in) operating activities		90,560	236,991	213,299	345,942
Financing Activities					
Bank credit facility	8	1,364	—	1,364	—
Senior notes	8	(114,010)	(59,429)	(114,010)	(59,429)
Purchase of common shares under Normal Course Issuer Bid	15	—	(70,556)	(2,536)	(90,384)
Share-based compensation – cash settled (tax withholding)	15	—	—	(7,232)	(4,952)
Dividends	15,18	(6,676)	(7,099)	(13,337)	(14,273)
Cash flow from/(used in) financing activities		(119,322)	(137,084)	(135,751)	(169,038)
Investing Activities					
Capital and office expenditures	18	(104,111)	(168,282)	(233,453)	(280,077)
Property and land acquisitions		(3,416)	(1,911)	(5,672)	(4,892)
Property divestments		(63)	9,601	5,515	10,023
Cash flow from/(used in) investing activities		(107,590)	(160,592)	(233,610)	(274,946)
Effect of exchange rate changes on cash and cash equivalents		453	(5,780)	10,590	(12,754)
Change in cash and cash equivalents		(135,899)	(66,465)	(145,472)	(110,796)
Cash and cash equivalents, beginning of period		142,076	318,996	151,649	363,327
Cash and cash equivalents, end of period		$ 6,177	$ 252,531	$ 6,177	$ 252,531

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 U.S. subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada.

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, 2020 and the 2019 comparative periods. 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, 2019.

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.

i. Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Actual results could differ from these estimates, and changes in estimates are recorded when known. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows, depreciation, depletion and accretion ("DD&A"), impairment of property, plant and equipment, asset retirement obligations, income taxes, ability to realize deferred income tax assets, impairment assessments of goodwill and the fair value of derivative instruments. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions.

In early March 2020, the World Health Organization declared the coronavirus ("COVID-19") outbreak a pandemic. Responses to the spread of COVID-19 have resulted in a challenging economic climate, with more volatile commodity prices and foreign exchange rates, and a decline in long-term interest rates. Although global economies began to recover during the second quarter, markets remain volatile as the timing of full economic recovery remains uncertain. It is difficult to reliably estimate the length or severity of these developments and their financial impact. The impacts of the economic downturn to Enerplus have been considered in management's estimates described above at June 30, 2020; however, estimates made during this period of extreme volatility are subject to a higher level of uncertainty and as a result, there may be a further prospective material impact in future periods.

3) ACCOUNTING POLICY CHANGES

Recently adopted accounting standards

a) Hedge Accounting

Effective January 1, 2020, the Company adopted hedge accounting in order to mitigate the foreign currency exposure related to its net investment in its U.S. subsidiary. The Company may designate certain U.S. dollar denominated debt as a hedge of its net investment in foreign operations for which the U.S. dollar is the functional currency. To be accounted for as a hedge, the U.S. dollar denominated debt must be designated an effective hedge, both at inception and on an ongoing basis. The required hedge documentation defines the relationship between the U.S. dollar denominated debt and the net investment in the U.S. subsidiary, as well as the Company's risk management objective and strategy for undertaking the hedging transaction. The Company formally assesses, both at inception and on an ongoing basis, whether the changes in fair value of the U.S. dollar denominated debt are highly effective in offsetting changes in fair value of the net investment in the U.S. subsidiary. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in Other Comprehensive Income/(Loss), net of tax, and are limited to the translation gain or loss on the net investment.

A reduction in the fair value of the net investment in the U.S. subsidiary or increase in the U.S. dollar denominated debt may result in a portion of the hedge becoming ineffective. If the hedging relationship ceases to be effective or is terminated, hedge accounting is not applied and subsequent gains or losses are recorded through net income/(loss).

b) Impairment of Financial Instruments

Enerplus adopted *ASC 326 – Financial Instruments – Credit Losses* effective January 1, 2020 using the modified retrospective method, with the cumulative effect on comparative periods reflected as an adjustment to retained earnings, if applicable. The adoption of the standard had no impact on the interim Consolidated Financial Statements, with the exception of the revised disclosures which are detailed in Note 16. As a result of this adoption, Enerplus has revised its accounting policy for financial instruments as follows:

The Company has adopted the current expected credit loss model for its accounts receivable, which requires the use of a lifetime expected loss provision. In making an assessment as to whether financial assets are credit-impaired, the Company considers: (i) historically realized bad debts; (ii) a counterparty's present financial condition and whether a counterparty has breached certain contracts; (iii) the probability that a counterparty will enter bankruptcy or other financial reorganization; (iv) changes in economic conditions that correlate to increased levels of default; and (v) the term to maturity of the specified receivable. The carrying amounts of receivables are reduced by the amount of the expected credit loss through an allowance account and losses are recognized within general and administrative expense in the Consolidated Statement of Income/(Loss). If the Company subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account.

c) Goodwill

Enerplus adopted ASU 2017-04, *Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment (Topic 350)* effective January 1, 2020 using the prospective method. The amended standard simplifies the goodwill impairment test. As a result of this adoption, Enerplus has revised its accounting policy for goodwill as follows:

Goodwill is assessed for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus first performs a qualitative assessment to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to the reporting unit's fair value, with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss). The loss recognized should not exceed the total amount of goodwill allocated to that reporting unit.

4) ACCOUNTS RECEIVABLE

($ thousands)	June 30, 2020	December 31, 2019
Accrued revenue	$ 93,362	$ 142,048
Accounts receivable – trade	31,744	37,736
Allowance for doubtful accounts	(3,711)	(3,665)
Total accounts receivable, net of allowance for doubtful accounts	$ 121,395	$ 176,119

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

As of June 30, 2020 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties[1]	$ 15,631,936	$ (14,401,864)	$ 1,230,072
Other capital assets	127,964	(107,218)	20,746
Total PP&E	$ 15,759,900	$ (14,509,082)	$ 1,250,818

As of December 31, 2019 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties[1]	$ 15,088,724	$ (13,541,362)	$ 1,547,362
Other capital assets	125,265	(105,021)	20,244
Total PP&E	$ 15,213,989	$ (13,646,383)	$ 1,567,606

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

6) IMPAIRMENT

a) Impairment of PP&E

($ thousands)	Three months ended June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
Oil and natural gas properties:				
Canada cost centre	$ 77,500	$ —	$ 77,500	$ —
U.S. cost centre	349,310	—	349,310	—
Impairment expense	$ 426,810	$ —	$ 426,810	$ —

The PP&E impairments for the three and six months ended June 30, 2020 were due to lower twelve month average trailing crude oil and natural gas prices. There was no PP&E impairment recorded for the six months ended June 30, 2019. If commodity prices remain at current levels, the twelve month average trailing prices will decline further, impacting Enerplus' ceiling value and resulting in an increased risk of future PP&E impairment.

The following table outlines the twelve month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from June 30, 2019 through June 30, 2020:

Period	WTI Crude Oil US$/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	Exchange Rate US$/CDN$
Q2 2020	$ 47.37	$ 54.94	$ 2.08	1.34
Q1 2020	55.96	66.42	2.30	1.33
Q4 2019	55.85	66.73	2.58	1.33
Q3 2019	57.77	62.79	2.83	1.33
Q2 2019	61.38	66.07	3.02	1.32

b) Impairment of Goodwill

Enerplus recorded goodwill impairment of $202.8 million related to its U.S. reporting unit for the period ended June 30, 2020 (December 31, 2019 - $451.1 million for the Canadian reporting unit). The impairment was a result of the ongoing deteriorating macroeconomic conditions and low commodity prices due to the COVID-19 pandemic, which resulted in a reduction in the fair value of the U.S. reporting unit. The estimated fair value of the U.S. reporting unit for the goodwill impairment test was based on its reserve values at forecast prices and costs. At June 30, 2020, there was no goodwill remaining on the Company's Condensed Consolidated Balance Sheet.

7) ACCOUNTS PAYABLE

($ thousands)	June 30, 2020	December 31, 2019
Accrued payables	$ 95,600	$ 105,928
Accounts payable – trade	149,329	185,612
Total accounts payable	$ 244,929	$ 291,540

8) DEBT

($ thousands)	June 30, 2020	December 31, 2019
Current:		
Senior notes	$ 110,780	$ 105,998
Long-term:		
Bank credit facility	1,052	—
Senior notes	412,439	500,635
Total debt	$ 524,271	$ 606,633

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)	CDN$ Carrying Value ($ thousands)
September 3, 2014	March 3 and Sept 3	5 equal annual installments beginning September 3, 2022	3.79%	US$200,000	US$105,000	$ 142,548
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	27,152
May 15, 2012	May 15 and Nov 15	4 equal annual installments beginning May 15, 2021	4.40%	US$355,000	US$238,400	323,652
June 18, 2009	June 18 and Dec 18	Final installment on June 18, 2021	7.97%	US$225,000	US$22,000	29,867
					Total carrying value	$ 523,219

During the three and six months ended June 30, 2020, Enerplus made its fourth US$22 million principal repayment on its 2009 senior notes and its first US$59.6 million principal repayment on its 2012 senior notes. During the three and six months ended June 30, 2019, Enerplus made its third US$22 million principal repayment on its 2009 senior notes and a $30 million bullet repayment on its 2012 senior notes.

9) ASSET RETIREMENT OBLIGATION

($ thousands)	June 30, 2020	December 31, 2019
Balance, beginning of year	$ 138,049	$ 126,112
Change in estimates	14,632	23,362
Property acquisitions and development activity	2,001	2,068
Divestments	(1,031)	(2,760)
Settlements	(11,127)	(16,715)
Accretion expense	3,647	5,982
Balance, end of period	$ 146,171	$ 138,049

Enerplus has estimated the present value of its asset retirement obligation to be $146.2 million at June 30, 2020 based on a total undiscounted liability of $356.3 million (December 31, 2019 – $138.0 million and $344.7 million, respectively). The asset retirement obligation was calculated using a weighted average credit-adjusted risk-free rate of 5.35% (December 31, 2019 – 5.50%).

10) LEASES

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

($ thousands)	June 30, 2020	December 31, 2019
Assets		
Operating right-of-use assets	$ 39,149	$ 48,729
Liabilities		
Current operating lease liabilities	$ 13,410	$ 17,541
Non-current operating lease liabilities	30,228	35,530
Weighted average remaining lease term (years)		
Operating leases	4.2	4.3
Weighted average discount rate		
Operating leases	4.1%	4.1%

The components of lease expense for the three and six months ended June 30, 2020 are as follows:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2020	2019	2020	2019
Operating lease cost	$ 4,182	$ 5,097	$ 9,315	$ 9,691
Variable lease cost	190	185	507	469
Short-term lease cost	1,893	3,811	7,177	7,932
Sublease income	(251)	(256)	(544)	(500)
Total	$ 6,014	$ 8,837	$ 16,455	$ 17,592

Maturities of lease liabilities, all of which are classified as operating leases at June 30, 2020 are as follows:

($ thousands)	Operating Leases
2020	$ 7,517
2021	14,754
2022	8,079
2023	6,914
2024	6,263
After 2025	4,158
Total lease payments	$ 47,685
Less imputed interest	(4,047)
Total discounted lease payments	$ 43,638
Current portion of lease liabilities	$ 13,410
Non-current portion of lease liabilities	$ 30,228

Supplemental information related to leases is as follows:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2020	2019	2020	2019
Cash amounts paid to settle lease liabilities:				
Operating cash flow used for operating leases	$ 3,913	$ 4,758	$ 8,841	$ 9,264
Right-of-use assets obtained in exchange for lease obligations:				
Operating leases	$ (3,473)	$ 1,105	$ (2,950)	$ 19,967

11) OIL AND NATURAL GAS SALES

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2020	2019	2020	2019
Oil and natural gas sales	$ 155,259	$ 403,206	$ 440,857	$ 759,582
Royalties(1)	(33,190)	(81,743)	(90,661)	(150,667)
Oil and natural gas sales, net of royalties	$ 122,069	$ 321,463	$ 350,196	$ 608,915

(1) Royalties above do not include production taxes which are reported separately on the Condensed Consolidated Statements of Income/(Loss).

Oil and natural gas revenue by country and by product for the three and six months ended June 30, 2020 and 2019 are as follows:

Three months ended June 30, 2020 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 13,027	$ 9,720	$ 2,122	$ 565	$ 620
United States	109,042	84,063	25,969	(1,006)	16
Total	$ 122,069	$ 93,783	$ 28,091	$ (441)	$ 636

Three months ended June 30, 2019 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 47,378	$ 41,386	$ 3,703	$ 1,582	$ 707
United States	274,085	217,830	51,766	4,489	—
Total	$ 321,463	$ 259,216	$ 55,469	$ 6,071	$ 707

(1) Royalties above do not include production taxes which are reported separately on the Condensed Consolidated Statements of Income/(Loss).
(2) U.S. sales of crude oil and natural gas relate primarily to the Company's North Dakota and Marcellus properties, respectively. Canadian crude oil sales relate primarily to the Company's waterflood properties.
(3) Includes third party processing income.

Six months ended June 30, 2020 ($ thousands)	Total revenue, net of royalties[1]	Crude oil[2]	Natural gas[2]	Natural gas liquids[2]	Other[3]
Canada	$ 40,120	$ 31,710	$ 5,510	$ 1,659	$ 1,241
United States	310,076	243,827	63,435	2,744	70
Total	$ 350,196	$ 275,537	$ 68,945	$ 4,403	$ 1,311

Six months ended June 30, 2019 ($ thousands)	Total revenue, net of royalties[1]	Crude oil[2]	Natural gas[2]	Natural gas liquids[2]	Other[3]
Canada	$ 100,276	$ 80,805	$ 14,071	$ 4,068	$ 1,332
United States	508,639	375,669	124,922	8,048	—
Total	$ 608,915	$ 456,474	$ 138,993	$ 12,116	$ 1,332

(1) Royalties above do not include production taxes which are reported separately on the Condensed Consolidated Statements of Income/(Loss).
(2) U.S. sales of crude oil and natural gas relate primarily to the Company's North Dakota and Marcellus properties, respectively. Canadian crude oil sales relate primarily to the Company's waterflood properties.
(3) Includes third party processing income.

12) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	Three months ended June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
General and administrative expense	$ 9,231	$ 11,796	$ 21,566	$ 24,227
Share-based compensation expense	4,263	3,884	11,113	13,163
General and administrative expense[1]	$ 13,494	$ 15,680	$ 32,679	$ 37,390

(1) Includes cash and non-cash amounts.

13) FOREIGN EXCHANGE

($ thousands)	Three months ended June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
Realized:				
Foreign exchange (gain)/loss	$ 64	$ 89	$ (55)	$ (29)
Translation of U.S. dollar cash held in Canada (gain)/loss	391	4,158	(2,712)	9,354
Unrealized:				
Translation of U.S. dollar debt and working capital (gain)/loss	1,038	(16,498)	(1,377)	(33,602)
Foreign exchange (gain)/loss	$ 1,493	$ (12,251)	$ (4,144)	$ (24,277)

Effective January 1, 2020, the Company elected to apply net investment hedge accounting. Any unrealized foreign exchange gain or loss recorded on certain U.S. dollar denominated debt held in Canada after adoption has been reflected in Other Comprehensive Income/(Loss) on the Consolidated Statements of Income/(Loss). See Note 3 for further details.

14) INCOME TAXES

($ thousands)	Three months ended June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
Current tax				
Canada	$ —	$ (13,941)	$ —	$ (13,941)
United States	(14,422)	13	(14,395)	(5,517)
Current tax expense/(recovery)	(14,422)	(13,928)	(14,395)	(19,458)
Deferred tax				
Canada	$ (25,629)	$ 34,808	$ 98,852	$ 5,249
United States	(73,299)	13,989	(88,430)	25,680
Deferred tax expense/(recovery)	(98,928)	48,797	10,422	30,929
Income tax expense/(recovery)	$ (113,350)	$ 34,869	$ (3,973)	$ 11,471

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 the following: 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 gains and losses, and share-based compensation.

During the three months ended June 30, 2020, Enerplus recorded an additional current tax recovery of $14.4 million for the final year of U.S. Alternative Minimum Tax ("AMT") refund.

At June 30, 2020, $28.9 million of the current income tax receivable related to remaining U.S. AMT refunds (December 31, 2019 - $27.8 million).

15) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized unlimited number of common shares issued: (thousands)	**Six months ended June 30, 2020** Shares	Amount	**Year ended December 31, 2019** Shares	Amount
Balance, beginning of year	221,744	$ 3,088,094	239,411	$ 3,337,608
Issued/(Purchased) for cash:				
Purchase of common shares under Normal Course Issuer Bid	(340)	(4,731)	(18,231)	(253,920)
Non-cash:				
Share-based compensation – treasury settled(1)	1,160	13,824	564	4,406
Cancellation of predecessor shares	(16)	(218)	—	—
Balance, end of period	222,548	$ 3,096,969	221,744	$ 3,088,094

(1) The amount of shares issued on LTI settlement is net of employee withholding taxes.

Dividends declared to shareholders for the three and six months ended June 30, 2020 were $6.7 million and $13.3 million, respectively (2019 – $7.0 million and $14.2 million, respectively).

Enerplus' Normal Course Issuer Bid ("NCIB") expired on March 25, 2020. The Company chose not to renew the NCIB upon expiry in order to conserve capital and preserve its liquidity. All repurchases were made in accordance with the NCIB at prevailing market prices plus brokerage fees, with consideration allocated to share capital up to the average carrying amount of the shares, and any excess allocated to accumulated deficit.

During the six months ended June 30, 2020, the Company repurchased 340,434 common shares under the NCIB at an average price of $7.44 per share, for total consideration of $2.5 million. Of the amount paid, $4.7 million was charged to share capital and $2.2 million was credited to accumulated deficit.

During the six months ended June 30, 2019, the Company repurchased 8,358,821 common shares under the previous NCIB at an average price of $10.80 per share, for total consideration of $90.4 million. Of the amount paid, $116.4 million was charged to share capital and $26.0 million was credited to accumulated deficit.

b) Share-based Compensation

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

($ thousands)	**Three months ended June 30,** 2020	2019	**Six months ended June 30,** 2020	2019
Cash:				
Long-term incentive plans (recovery)/expense	$ 1,186	$ (626)	$ (1,561)	$ 711
Non-cash:				
Long-term incentive plans	3,550	4,263	11,239	12,306
Equity swap (gain)/loss	(473)	247	1,435	146
Share-based compensation expense	$ 4,263	$ 3,884	$ 11,113	$ 13,163

i) Long-term Incentive ("LTI") Plans

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Director Deferred Share Unit ("DSU") and Director RSU ("DRSU") activity for the six months ended June 30, 2020:

(thousands of units)	Cash-settled LTI plans Director Plans	Equity-settled LTI plans PSU[(1)]	Equity-settled LTI plans RSU	Total
Balance, beginning of year	422	2,139	1,531	4,092
Granted	128	1,154	1,103	2,385
Vested	—	(652)	(741)	(1,393)
Forfeited	—	(88)	(62)	(150)
Balance, end of period	550	2,553	1,831	4,934

(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, 2020, the Company recorded a cash share-based compensation expense of $1.2 million and recovery of $1.6 million, respectively (June 30, 2019 – recovery of $0.6 million and expense of $0.7 million, respectively).

As of June 30, 2020, a liability of $2.1 million (December 31, 2019 – $3.9 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 to 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, 2020 ($ thousands, except for years)	PSU[(1)]	RSU	Total
Cumulative recognized share-based compensation expense	$ 20,598	$ 9,593	$ 30,191
Unrecognized share-based compensation expense	13,936	9,762	23,698
Fair value	$ 34,534	$ 19,355	$ 53,889
Weighted-average remaining contractual term (years)	1.9	1.6	

(1) Includes estimated performance multipliers.

For the six months ended June 30, 2020, $7.2 million (2019 – $5.0 million) in cash withholding taxes were paid on the PSU and RSU settlements.

ii) Stock Option Plan

At June 30, 2020 all stock options are fully vested and any related non-cash share-based compensation expense has been fully recognized. All remaining outstanding stock options expired in March 2020.

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

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

(thousands, except per share amounts)	Three months ended June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
Net income/(loss)	$ (609,323)	$ 85,084	$ (606,447)	$ 104,242
Weighted average shares outstanding – Basic	222,557	235,490	222,457	237,197
Dilutive impact of share-based compensation[(1)]	—	2,699	—	2,750
Weighted average shares outstanding – Diluted	222,557	238,189	222,457	239,947
Net income/(loss) per share				
Basic	$ (2.74)	$ 0.36	$ (2.73)	$ 0.44
Diluted	$ (2.74)	$ 0.36	$ (2.73)	$ 0.43

(1) For the three and six months ended June 30, 2020, the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

16) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At June 30, 2020, the carrying value of cash, accounts receivable, accounts payable, and dividends payable approximated their fair value due to the short-term maturity of the instruments.

At June 30, 2020, the senior notes had a carrying value of $523.2 million and a fair value of $515.7 million (December 31, 2019 – $606.6 million and $613.8 million, respectively).

The fair value of derivative contracts and senior notes 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 for the three and six months ended June 30, 2020 and 2019:

	Three months ended June 30,		Six months ended June 30,		Income Statement
Gain/(Loss) ($ thousands)	2020	2019	2020	2019	Presentation
Equity Swaps	$ 473	$ (247)	$ (1,435)	(146)	G&A expense
Commodity Derivative Instruments:					
Oil	(64,402)	23,617	33,934	(63,312)	Commodity derivative
Gas	—	4,983	—	(3,517)	instruments
Total	$ (63,929)	$ 28,353	$ 32,499	$ (66,975)	

The following table summarizes the effects of Enerplus' commodity derivative instruments on the Condensed Consolidated Statements of Income/(Loss) and Comprehensive Income/(Loss):

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2020	2019	2020	2019
Change in fair value gain/(loss)	$ (64,402)	$ 28,600	$ 33,934	$ (66,829)
Net realized cash gain/(loss)	53,507	(1,178)	86,512	9,384
Commodity derivative instruments gain/(loss)	$ (10,895)	$ 27,422	$ 120,446	$ (57,445)

The following table summarizes the fair values of derivative financial instruments at the respective period ends:

	June 30, 2020		December 31, 2019	
	Assets	Liabilities	Assets	Liabilities
($ thousands)	Current	Current	Current	Current
Equity Swaps	$ —	$ 3,652	$ —	$ 2,217
Commodity Derivative Instruments:				
Oil	46,186	2,199	10,570	517
Total	$ 46,186	$ 5,851	$ 10,570	$ 2,734

c) Risk Management

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 derivatives and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes, net of royalties and production taxes.

The following tables summarize the Company's price risk management positions at August 6, 2020:

Crude Oil Instruments:

Instrument Type[1][2]	bbls/day	US$/bbl
Jul 1, 2020 – Sep 30, 2020		
WTI Swap	7,000	36.02
WTI Purchased Put	21,000	57.20
WTI Sold Put	21,000	47.14
WTI Sold Call	5,000	65.00
WTI – Brent Swap (Purchase)	4,400	(8.03)
WTI – Brent Swap (Sale)	4,400	(3.62)
Oct 1, 2020 – Dec 31, 2020		
WTI Purchased Put	21,000	57.20
WTI Sold Put	21,000	47.14
WTI Sold Call	5,000	65.00
WTI – Brent Swap (Purchase)	4,400	(8.03)
WTI – Brent Swap (Sale)	4,400	(3.62)
Jan 1, 2021 - Jun 30, 2021		
WTI Purchased Put	6,000	40.00
WTI Sold Put	6,000	32.00
WTI Sold Call	6,000	50.00

(1) Transactions with a common term have been aggregated and presented at a weighted average price/bbl before premiums.
(2) The total average deferred premium on outstanding hedges is US$1.75/bbl from July 1, 2020 to December 31, 2020 and US$0.03/bbl from January 1, 2021 to June 30, 2021.

Enerplus has fixed physical differential sales agreements for approximately 16,000 bbls/day in North Dakota at an estimated price of approximately US$6.00/bbl below WTI for the remainder of 2020.

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations, U.S. dollar denominated senior notes, cash deposits and working capital. Additionally, Enerplus' crude oil sales and a portion of its natural gas sales are based on U.S. dollar indices. To mitigate exposure to fluctuations in foreign exchange, Enerplus may enter into foreign exchange derivatives. At June 30, 2020, Enerplus did not have any foreign exchange derivatives outstanding.

Enerplus may designate certain U.S. dollar denominated debt as a hedge of its net investment in foreign operations for which the U.S. dollar is the functional currency. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in Other Comprehensive Income/(Loss), net of tax, and are limited to the translation gain or loss on the net investment. At June 30, 2020, Enerplus designated all of its US$385.4 million senior notes as a hedge of the Company's net investment in its U.S. subsidiary. For the three and six months ended June 30, 2020, Enerplus recorded a $19.5 million gain and $30.6 million loss, net of tax of nil, respectively, on its net investment hedge.

Interest Rate Risk:

At June 30, 2020, approximately all of Enerplus' debt was based on fixed interest rates and Enerplus had no interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 15. Enerplus has entered into various equity swaps maturing in 2020 that effectively fix the future settlement cost on a portion of its cash settled LTI plans.

ii) Credit Risk

Credit risk represents the financial loss Enerplus would experience due to the potential non-performance of counterparties to its financial instruments. Enerplus is exposed to credit risk mainly through its joint venture, marketing and financial counterparty receivables. Enerplus has appropriate policies and procedures in place to manage its credit risk; however, given the recent rapid decline 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.

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At June 30, 2020, approximately 85% of Enerplus' marketing receivables were with companies considered investment grade.

Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts of future payments or seeking other remedies including legal action. Enerplus' allowance for doubtful accounts balance at June 30, 2020 was $3.7 million (December 31, 2019 – $3.7 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 share capital. Enerplus' objective is to provide adequate short and long 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 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, and acquisition and divestment activity.

At June 30, 2020, the Company was in full compliance with all covenants under the bank credit facility and outstanding senior notes. Enerplus expects to manage its business within these financial ratios during 2020; however, current oil and gas prices have created a significant level of uncertainty which may challenge this expectation. If the Company exceeds or anticipates exceeding its covenants, the Company may be required to repay, refinance or renegotiate the terms of the debt.

17) COMMITMENTS AND CONTINGENCIES

As of the date of this report, there were no material changes to Enerplus' contractual obligations and commitments outside the ordinary course of business as reported in the Company's annual audited Consolidated Financial Statements as of December 31, 2019.

Enerplus is subject to various legal claims and actions arising in the normal course of business. Although the outcome of such claims and actions cannot be predicted with certainty, the Company does not expect these matters to have a material impact on the Consolidated Financial Statements. In instances where the Company determines that a loss is probable and the amount can be reasonably estimated, an accrual is recorded.

18) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2020	2019	2020	2019
Accounts receivable	$ (13,557)	$ 37,580	$ 67,259	$ 23,401
Other assets	207	4,891	(200)	1,864
Accounts payable	34,246	8,985	(25,857)	(28,223)
	$ 20,896	$ 51,456	$ 41,202	$ (2,958)

b) Changes in Other Non-Cash Working Capital

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2020	2019	2020	2019
Non-cash financing activities(1)	$ (1)	$ (65)	$ 8	$ (77)
Non-cash investing activities(2)	(63,094)	41,039	(26,899)	91,140

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

c) Other

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2020	2019	2020	2019
Income taxes paid/(received)	$ 71	$ (57,663)	$ (30,097)	$ (57,599)
Interest paid	12,966	14,390	16,253	17,649

BOARD OF DIRECTORS

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

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

Karen E. Clarke-Whistler[(5)(9)(11)]
Corporate Director
Toronto, Ontario

Michael R. Culbert[(3)(5)(10)]
Corporate Director
Calgary, Alberta

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

Robert B. Hodgins[(3)(6)(9)]
Corporate Director
Calgary, Alberta

Susan M. MacKenzie[(4)(9)(11)]
Corporate Director
Calgary, Alberta

Elliott Pew
Corporate Director
Calgary, Alberta

Jeffrey W. Sheets[(5)(7)(12)]
Corporate Director
Houston, Texas

Sheldon B. Steeves[(3)(8)(11)]
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 Committee
(8) Chair of the Reserves Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chair of the Compensation & Human Resources Committee
(11) Member of the Safety & Social Responsibility Committee
(12) Chair of the Safety & Social Responsibility Committee

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas
President & Chief Executive Officer

Wade D. Hutchings
Senior Vice President & Chief Operating Officer

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

Garth R. Doll
Vice President, Marketing

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

Nathan D. Fisher
Vice President, U.S. Business Unit

Daniel J. Fitzgerald
Vice President, Business Development

John E. Hoffman
Vice President, Canadian Assets & Corporate Sustainability

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

Edward L. McLaughlin
President, U.S. Operations

Shaina B. Morihira
Vice President, Finance

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

Computershare Trust Company of Canada
Calgary, Alberta
Toll free: 1.866.921.0978

U.S. CO-TRANSFER AGENT

Computershare Trust Company, N.A.
Golden, Colorado

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

U.S. OFFICE

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Denver, Colorado 80202

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ABBREVIATIONS

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

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