SECOND QUARTER REPORT

Six Months Ended June 30, 2021

enerPLUS

SELECTED FINANCIAL RESULTS	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Financial (CDN$, thousands, except ratios)				
Net Income/(Loss)	$ (59,664)	$ (609,323)	$ (44,967)	$ (606,447)
Adjusted Net Income/(Loss)(1)	67,932	(41,185)	124,183	(20,095)
Cash Flow from Operating Activities	136,902	90,560	174,141	213,299
Adjusted Funds Flow(1)	184,320	69,997	312,435	183,224
Dividends to Shareholders - Declared	11,040	6,675	18,405	13,345
Total Debt Net of Cash(1)	1,132,841	518,094	1,132,841	518,094
Capital Spending	129,903	40,084	195,434	203,709
Property and Land Acquisitions	408,764	3,416	1,037,332	5,672
Property Divestments	(17)	(63)	4,978	5,515
Net Debt to Adjusted Funds Flow Ratio(1)(2)	2.3x	1.0x	2.3x	1.0x
Financial per Weighted Average Shares Outstanding				
Net Income /(Loss) - Basic	$ (0.23)	$ (2.74)	$ (0.18)	$ (2.73)
Net Income/(Loss) - Diluted	(0.23)	(2.74)	(0.18)	(2.73)
Weighted Average Number of Shares Outstanding (000's) - Basic	256,750	222,557	250,443	222,457
Weighted Average Number of Shares Outstanding (000's) - Diluted	256,750	222,557	250,443	222,457
Selected Financial Results per BOE(3)(4)				
Crude Oil & Natural Gas Sales(5)	$ 48.60	$ 19.53	$ 46.38	$ 26.11
Royalties and Production Taxes	(12.58)	(5.15)	(11.74)	(6.74)
Commodity Derivative Instruments	(3.53)	6.73	(3.02)	5.12
Operating Expenses	(8.43)	(6.84)	(8.16)	(7.90)
Transportation Costs	(3.45)	(4.28)	(3.68)	(4.11)
Cash General and Administrative Expenses	(1.04)	(1.14)	(1.28)	(1.26)
Cash Share-Based Compensation	(0.22)	(0.15)	(0.27)	0.09
Interest, Foreign Exchange and Other Expenses	(1.39)	(1.69)	(1.34)	(1.29)
Current Income Tax Recovery/(Expenses)	(0.40)	1.81	(0.22)	0.85
Adjusted Funds Flow(1)	$ 17.56	$ 8.82	$ 16.67	$ 10.87

SELECTED OPERATING RESULTS	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Average Daily Production(4)				
Crude Oil (bbls/day)	61,803	43,168	52,187	46,106
Natural Gas Liquids (bbls/day)	9,890	4,929	8,245	5,137
Natural Gas (Mcf/day)	261,945	235,579	258,863	249,246
Total (BOE/day)	115,351	87,360	103,576	92,784
% Crude Oil and Natural Gas Liquids	62%	55%	58%	55%
Average Selling Price (4)(5)				
Crude Oil (per bbl)	$ 76.67	$ 30.55	$ 72.90	$ 41.59
Natural Gas Liquids (per bbl)	22.72	(0.96)	28.06	6.16
Natural Gas (per Mcf)	2.45	1.63	2.96	1.87
Net Wells Drilled	5	3	5	37

(1) These are non-GAAP measures that do not have any standardized meaning under the Company's GAAP and, therefore, may not be directly comparable to similar measures presented by other entities. See "Non-GAAP Measures" section in the following MD&A.
(2) Ratio does not include trailing adjusted funds flow from the Bruin and Dunn County acquisitions.
(3) Non-cash amounts have been excluded.
(4) Based on Company interest production volumes. See "Basis of Presentation" section in the following MD&A.
(5) Before transportation costs, royalties and the effects of commodity derivative instruments.

Average Benchmark Pricing	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
WTI crude oil (US$/bbl)	$ 66.07	$ 27.85	$ 61.96	$ 37.01
Brent (ICE) crude oil (US$/bbl)	69.02	33.27	65.06	42.12
NYMEX natural gas – last day (US$/Mcf)	2.83	1.72	2.76	1.83
USD/CDN average exchange rate	1.23	1.39	1.25	1.37

Share Trading Summary For the three months ended June 30, 2021	CDN[(1)] - ERF (CDN$)	U.S.[(2)] - ERF (US$)
High	$ 9.28	$ 7.54
Low	$ 6.09	$ 4.83
Close	$ 8.91	$ 7.19

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

2021 Dividends Declared per Share	CDN$	US$[(1)]
First Quarter Total	$ 0.03	$ 0.02
Second Quarter Total	$ 0.04	$ 0.04
Total	$ 0.07	$ 0.06

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

NEWS RELEASE

HIGHLIGHTS

- Successfully closed the strategic acquisition of assets in the Williston Basin from Hess Corporation on April 30, 2021
- Achieved record production in the second quarter of 115,351 BOE per day, 26% higher than the prior quarter
- Adjusted funds flow was $184.3 million in the second quarter, which exceeded capital spending of $129.9 million, generating free cash flow of $54.4 million
- Annual average 2021 production guidance revised to 112,000 to 115,000 BOE per day, including 69,500 to 71,500 barrels per day of liquids reflecting higher mid-points, with no change in 2021 capital spending guidance
- Increasing return of capital to shareholders: quarterly dividend increased 15% to $0.038 per share; reinitiating share repurchase program
- Capital efficiencies continuing to improve: well costs in North Dakota are tracking US$5.7 million per well, a 25% reduction compared to 2019
- 2021 Bakken crude oil price differential guidance strengthened to US$2.35 per barrel below WTI (from US$3.25)
- Estimated 2021 free cash flow of over $450 million based on current forward strip commodity prices
- Net debt to adjusted funds flow ratio estimated to be at or below 1.0x by year-end 2021 based on current forward strip commodity prices

"Our second quarter results reflect the increasing scale of our business and continued strong operational momentum," said Ian C. Dundas, President and CEO. "We delivered record production, capital efficiency gains along with an increasing free cash flow profile. The 15% increase to our quarterly dividend—our second dividend increase this year—and resumption of our share repurchase program underscores our commitment to providing increasing capital returns to shareholders. While we are prioritizing debt reduction in the near term, we will continue to evaluate returning incremental free cash flow to shareholders and are well positioned to meaningfully enhance our shareholder returns upon achieving our $400 million debt reduction target."

SECOND QUARTER SUMMARY

Production in the second quarter of 2021 was 115,351 BOE per day, an increase of 32% compared to the same period a year ago, and 26% higher than the prior quarter. Crude oil and natural gas liquids production in the second quarter of 2021 was 71,693 barrels per day, an increase of 49% compared to the same period a year ago, and 46% higher than the prior quarter. The increased production compared to the same period in 2020 was due to the contribution from the Company's Williston Basin acquisitions in 2021 and lower production during the second quarter of 2020 due to reduced activity and temporarily curtailed volumes in response to the low crude oil prices.

Enerplus reported a second quarter 2021 net loss of $59.7 million, or $0.23 per share, compared to a net loss of $609.3 million, or $2.74 per share, in the same period in 2020 which included non-cash impairments. The net loss recognized in the second quarter of 2021 was primarily due to non-cash mark to market losses related to commodity derivative instruments. Adjusted net income for the second quarter of 2021 was $67.9 million, or $0.26 per share, compared to an adjusted net loss of $41.2 million, or $0.19 per share, during the same period in 2020. Adjusted net income was higher compared to the same period in 2020 due to higher commodity prices and increased production.

Enerplus' second quarter 2021 realized Bakken oil price differential was US$2.76 per barrel below WTI, compared to US$4.36 per barrel below WTI in the second quarter of 2020. Bakken crude oil differentials improved relative to the prior year period due to increased U.S. refinery demand and significant available pipeline capacity in the basin.

The Company's realized Marcellus natural gas price differential was US$0.89 per Mcf below NYMEX during the second quarter of 2021 compared to US$0.49 per Mcf below NYMEX in the second quarter of 2020. The weaker second quarter 2021 differential reflected significant unplanned regional pipeline maintenance.

In the second quarter of 2021, Enerplus' operating expenses were $8.43 per BOE, compared to $6.84 per BOE during the same period in 2020. Operating expenses in the second quarter of 2020 were impacted by price-related production curtailments and lower well servicing activity.

Second quarter transportation costs were $3.45 per BOE and cash general and administrative ("G&A") expenses were $1.04 per BOE.

Enerplus recorded a current tax expense of $4.2 million in the second quarter of 2021 related to U.S. federal taxes as a result of higher expected income in 2021.

Exploration and development capital spending was $129.9 million in the second quarter of 2021. The Company paid $11.0 million in dividends in the quarter.

Enerplus closed its strategic acquisition of certain assets in the Williston Basin from Hess Corporation on April 30, 2021, for total cash consideration of US$312 million, subject to customary purchase price adjustments.

At the end of the second quarter of 2021, the Company had total debt of $1,208.1 million and cash on hand of $75.3 million. Enerplus made principal repayments of US$81.6 million on its 2009 and 2012 senior notes during the quarter.

ASSET ACTIVITY

Williston Basin production averaged 72,390 BOE per day (73% crude oil) during the second quarter of 2021, an increase of 64% compared to the same period a year ago, and 53% higher than the prior quarter. During the second quarter the Company drilled four gross operated wells (100% working interest) and brought 23 gross operated wells on production (83% average working interest). Enerplus continued to drive capital efficiency improvements through faster drilling and completions cycle times and other efficiencies. Enerplus set a company record in the second quarter drilling a two-mile lateral section in 48 hours (lateral spud to total depth). Total well costs in North Dakota are now expected to average US$5.7 million per well in 2021, a reduction of 25% compared to 2019 levels and well below the 2021 target of US$6.1 million.

Marcellus production averaged 192 MMcf per day during the second quarter of 2021, a decrease of 3% compared to the same period in 2020, and 6% lower than the prior quarter.

Canadian waterflood production averaged 7,240 BOE per day (95% crude oil) during the second quarter of 2021, an increase of 14% compared to the same period in 2020, and 2% lower than the prior quarter.

FREE CASH FLOW PRIORITIES

Enerplus expects to allocate approximately 90% of its free cash flow, after dividends, to debt reduction. The Company is targeting a net debt to adjusted funds flow ratio at or below 1.0x assuming a $50 per barrel WTI oil price environment, representing a debt reduction target of approximately $400 million from second quarter 2021 levels. Enerplus estimates it will achieve its debt reduction target by mid-2022 based on current forward strip commodity prices. The remaining approximately 10% of free cash flow, after dividends, is expected to be allocated to incremental capital returns to shareholders, including potential dividend increases and share repurchases. The Company will continue to evaluate this free cash flow allocation as it makes progress on its debt reduction target with the expectation of increasing the allocation of free cash flow to shareholders once its debt target is achieved, assuming a supportive commodity price environment.

Given the Company's significant increase in cash flow generation following its strategic acquisitions in the first half of 2021, Enerplus believes the business can support a higher dividend while continuing to prioritize debt reduction. As a result, the Board of Directors has approved a 15% increase to the Company's quarterly dividend to $0.038 per share payable on September 15, 2021 to shareholders of record on August 31, 2021. This is Enerplus' second dividend increase year to date and represents a 27% increase, on an annualized basis, from the Company's dividend level at the start of the year.

Enerplus also received approval from its Board of Directors to commence a Normal Course Issuer Bid ("NCIB"), subject to approval by the Toronto Stock Exchange ("TSX"). The proposed renewal will be for 10% of the public float (within the meaning under the TSX rules).

FIVE-YEAR OUTLOOK UPDATE

Enerplus has updated year one (2021) of its five-year outlook to reflect year to date commodity prices and the forward strip for the remainder of the year. The years 2022 to 2025 continue to be based on US$50 to US$55 per barrel WTI flat oil price assumptions. Based on this, the Company has increased the estimated cumulative free cash flow over this period to approximately $1.5 to $2.0 billion.

2021 GUIDANCE UPDATE

Enerplus revised its 2021 average production guidance to 112,000 to 115,000 BOE per day, including liquids production of 69,500 to 71,500 barrels per day due to outperformance year to date. Capital spending guidance is unchanged.

Enerplus narrowed its 2021 Bakken crude oil price differential guidance to US$2.35 per barrel below WTI, compared to US$3.25 per barrel below WTI previously. The improved differential guidance is due to strong year to date pricing and additional firm capacity on the Dakota Access Pipeline ("DAPL") secured in connection with the pipeline's expansion. Enerplus now has approximately 10,000 barrels per day of firm transportation on DAPL.

As a result of ongoing pipeline maintenance in the Marcellus, Enerplus widened its 2021 Marcellus natural gas price differential to US$0.65 per Mcf below NYMEX, compared to US$0.55 per Mcf below NYMEX previously.

The Company expects to incur current income tax expense of US$5 to US$7 million in 2021.

A summary of the Company's 2021 guidance is provided below.

2021 Guidance	
Capital spending	$360 to $400 million
Average annual production	112,000 - 115,000 BOE/day (from 111,000 - 115,000 BOE/day)
Average annual crude oil and natural gas liquids production	69,500 - 71,500 bbls/day (from 68,500 - 71,500 bbls/day)
Average royalty and production tax rate	26%
Operating expense	$8.25/BOE
Transportation expense	$3.85/BOE
Cash G&A expense	$1.25/BOE
Current Income Tax expense	US$5 - $7 million

2021 Full-Year Differential/Basis Outlook(1)	
U.S. Bakken crude oil differential (compared to WTI crude oil)(2)	US$(2.35)/bbl (from US$(3.25)/bbl)
Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.65)/Mcf (from US$(0.55)/Mcf)

(1) Excluding transportation costs.
(2) Assuming the Dakota Access Pipeline ("DAPL") continues to operate.

PRICE RISK MANAGEMENT

Enerplus' commodity hedging positions are provided in the table below.

Enerplus' Financial Commodity Hedging Contracts (As at August 4, 2021)

	WTI Crude Oil(1)(2) (US$bbl)				NYMEX Natural Gas (US$/Mcf)	
	Jul 1, 2021 – Dec 31, 2021	**Jan 1, 2022 – Dec 31, 2022**	**Jan 1, 2023 – Oct 31, 2023**	**Nov 1, 2023 – Dec 31, 2023**	**Jul 1, 2021 – Oct 31, 2021**	**Nov 1, 2021 – Mar 31, 2022**
Swaps						
Volume (bbls/day)	–	–	–	–	60,000	–
Sold Swaps	–	–	–	–	$ 2.90	–
Collars						
Volume (bbls/day)	23,000	17,000	–	–	40,000	40,000
Sold Puts	$ 36.39	$ 40.00	–	–	$ 2.15	–
Purchased Puts	$ 46.39	$ 50.00	–	–	$ 2.75	$ 3.43
Sold Calls	$ 56.70	$ 57.91	–	–	$ 3.25	$ 6.00
Hedges acquired from Bruin(3)						
Swaps						
Volume (bbls/day)	8,465	3,828	250		–	–
Sold Swaps	$ 42.52	$ 42.35	$ 42.10		–	–
Collars						
Volume (bbls/day)	–	–	2,000	2,000	–	–
Purchased Puts	–	–	$ 5.00	$ 5.00	–	–
Sold Calls	–	–	$ 75.00	$ 75.00	–	–

(1) The total average deferred premium spent on outstanding hedges is US$0.84/bbl from July 1, 2021 - December 31, 2021 and US$1.22/bbl from January 1, 2022 - December 31, 2022.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Upon closing of the Bruin Acquisition, Bruin's outstanding hedges were recorded at a fair value liability of $96.5 million. At June 30, 2021, the fair value of the Bruin hedges was a liability of $100.0 million. For the three and six months ended June 30, 2021 we recorded a realized loss of $2.2 million and $1.7 million, respectively, on the settlement of the Bruin hedges. In addition, we recognized an unrealized loss of $52.8 million and $35.4 million, respectively, for the change in the fair value of the Bruin hedges over the same periods. See Note 17 to the Q2 2021 Financial Statements for further detail.

Q2 2021 CONFERENCE CALL DETAILS

A conference call hosted by Ian C. Dundas, President and CEO will be held at 9:00 AM MT (11:00 AM ET) on Friday, August 6, 2021 to discuss these results. Details of the conference call are as follows:

Date:	Friday, August 6, 2021
Time:	9:00 AM MT (11:00 AM ET)
Dial-In:	587-880-2171 (Alberta) 1-888-390-0546 (Toll Free)
Conference ID:	07577276
Audiocast:	https://produceredition.webcasts.com/starthere.jsp?ei=1470850&tp_key=75a2e3927a

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

Replay Dial-In:	1-888-390-0541 (Toll Free)
Replay Passcode:	577276 #

Summary of Average Daily Production[1]

	Three months ended June 30, 2021					Six months ended June 30, 2021				
	Williston Basin	Marcellus	Canadian Waterfloods	Other[2]	Total	Williston Basin	Marcellus	Canadian Waterfloods	Other[2]	Total
Tight oil (bbl/d)	52,896	—	—	1,900	54,797	43,743	—	—	1,347	45,090
Light & medium oil (bbl/d)	—	—	2,912	86	2,998	—	—	2,970	65	3,035
Heavy oil (bbl/d)	—	—	3,983	25	4,008	—	—	4,045	17	4,063
Total crude oil (bbl/d)	**52,896**	—	**6,895**	**2,012**	**61,803**	43,743	—	7,015	1,429	52,188
Natural gas liquids (bbl/d)	9,257	—	129	504	9,890	7,634	—	76	535	8,245
Shale gas (Mcf/d)	61,418	191,602	—	1,535	254,555	51,300	197,760	—	1,337	250,396
Conventional natural gas (Mcf/d)	—	—	1,296	6,093	7,389	—	—	1,238	7,230	8,467
Total natrual gas (Mcf/d)	**61,418**	**191,602**	**1,296**	**7,628**	**261,945**	51,300	197,760	1,238	8,566	258,863
Total Production (BOE/day)	**72,390**	**31,934**	**7,240**	**3,786**	**115,351**	**59,928**	**32,960**	**7,297**	**3,392**	**103,576**

(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, 2021				Six months ended June 30, 2021			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	4	4.0	—	—	4	4.0	—	—
Marcellus	—	—	14	0.6	—	—	28	0.8
Canadian Waterfloods	—	—	—	—	—	—	—	—
Other[2]	—	—	—	—	—	—	2	0.3
Total	**4**	**4.0**	**14**	**0.6**	**4**	**4.0**	**30**	**1.1**

(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, 2021				Six months ended June 30, 2021			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	23	19.1	1	0.4	26	22.1	1	0.4
Marcellus	—	—	20	1.4	—	—	36	1.8
Canadian Waterfloods	—	—	—	—	—	—	—	—
Other[2]	—	—	—	—	3	2.6	2	0.3
Total	**23**	**19.1**	**21**	**1.8**	**29**	**24.7**	**39**	**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), "MBOE" (one thousand barrels of oil equivalent), and "MMBOE" (one million barrels of oil equivalent). Enerplus has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.

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 disclosure requirements and industry practice, oil and gas sales and production volumes are presented on a gross basis before deduction of royalties. All production volumes and oil and gas sales 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 forward-looking statements within the meaning of applicable securities laws ("forward-looking information"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "believes" and "plans" 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 benefits of the Hess asset and Bruin acquisition; expected impact of the Hess asset and Bruin acquisitions on Enerplus' operations and financial results, including expected free cash flow in 2021 and beyond and year-end net debt to adjusted funds flow ratio; anticipated impact of the Hess asset and Bruin acquisitions on Enerplus' future costs and expenses; the renewal of Enerplus' NCIB and terms thereof; expected capital spending levels in 2021 and the future and the impact thereof on our production levels and land holdings; expected production volumes and updated 2021 and future production guidance; expected operating strategy in 2021; the effect of Enerplus' participation in the DAPL expansion on increased crude oil transportation; 2021 average production volumes, timing thereof and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the expected effectiveness of such hedges in protecting our adjusted funds flow in 2021 and the future; the results from our drilling program and the timing of related production and ultimate well recoveries; oil and natural gas prices and differentials, our commodity risk management program in 2021 and expected hedging gains; expectations regarding our realized oil and natural gas prices; expected operating, transportation, cash G&A and financing costs; expected reduction in well costs; future royalty rates on our production and future production taxes; net debt to adjusted funds-flow ratio, financial capacity and liquidity and capital resources to fund capital spending, dividends and working capital requirements; expectations regarding our ability to comply with debt covenants under our bank credit facility, term loan and outstanding senior notes; and expectations regarding payment of increased dividends.

The forward-looking information contained in this news release reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated, including considering the Hess asset and Bruin acquisition; that our development plans will achieve the expected results; that a 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 and estimated commodity prices, differentials and cost assumptions; the continued ability to operate DAPL; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions, including expectations regarding the duration and overall impact of COVID-19; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the 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; the extent of our liabilities; the rates used to calculate the amount of our future abandonment and reclamation costs and asset retirement obligations; the availability of technology and processes to achieve environmental targets. In addition, Enerplus' 2021 outlook contained in this news release is based on the following rest of year prices: US$69/bbl WTI, US$3.92/Mcf NYMEX, and a USD/CDN exchange rate of 1.26. Furthermore, in addition, years 2022 to 2025 of Enerplus' five-year outlook contained in this news release is based on the following: a WTI price of between US$50.00/bbl and US$55.00/bbl, a NYMEX price of US$2.75/Mcf and a USD/CDN exchange *rate of 1.27. We believe 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.*

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 price environment or further volatility in commodity prices; changes in realized prices of Enerplus' products from those currently anticipated; changes in the demand for or supply of our products; failure to realize the anticipated benefits of the Hess asset and Bruin acquisitions; unanticipated operating results, results from our capital spending activities or production declines; legal proceedings in connection with DAPL; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; 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; changes in law or government programs or policies in Canada or the United States; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in Enerplus' 2020 MD&A and in our other public filings).

The purpose of our estimated free cash flow disclosure is to assist readers in understanding our expected and targeted financial results and this information may not be appropriate for other purposes. The forward-looking information contained in this press release speaks only as of the date of this press release, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.

NON-GAAP MEASURES

In this news release, Enerplus uses the terms "adjusted funds flow", "adjusted net income", "free cash flow" "total debt net of cash" and "net debt to adjusted funds flow ratio" measures to analyze operating performance, leverage and liquidity. "Adjusted funds flow" is calculated as net cash 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, goodwill impairment, gain on divestment of assets, unrealized foreign exchange gain/loss, and the tax effect of these items. "Free cash flow" is calculated as adjusted funds flow minus capital spending. "Total debt net of cash" is calculated as senior notes plus term loan plus outstanding bank credit facility balance, minus cash and cash equivalents". "Net debt to adjusted funds flow" is calculated as total debt net of cash, including restricted cash, divided by adjusted funds flow.

Enerplus believes that, in addition to cash flow from operating activities, net earnings and other measures prescribed by U.S. GAAP, the terms "adjusted funds flow", "adjusted net income", "free cash flow", "total debt net of cash" and "net debt to adjusted funds flow" 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' 2020 MD&A.

Electronic copies of Enerplus Corporation's Second Quarter 2021 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 5, 2021 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, 2021 and 2020 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2020 and 2019 and for the years ended December 31, 2020, 2019 and 2018; and
- our MD&A for the year ended December 31, 2020 (the "Annual MD&A").

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" at the end of the MD&A for further information. In addition, the following MD&A contains disclosure regarding certain risks and uncertainties associated with Enerplus' business. See "Risk Factors and Risk Management" in the Annual MD&A and "Risk Factors" in Enerplus' annual information form for the year ended December 31, 2020 (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 reclassified to conform with current period presentation.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 bbl and crude oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcf. BOE and Mcfe measures are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1 or 0.167:1, as applicable, utilizing a conversion on this basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. 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. All references to "natural gas" in this MD&A include conventional natural gas and shale gas.

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

For more details on our acquisition (the "Bruin Acquisition") of Bruin E&P HoldCo, LLC ("Bruin"), see Note 4 to the Interim Financial Statements as well as the material change report dated January 29, 2021 and the business acquisition report dated April 13, 2021, each available under Enerplus' SEDAR profile at www.sedar.com and Enerplus' EDGAR profile under Form 6-K at www.sec.gov.

For more details on our acquisition (the "Dunn County Acquisition" or the "Hess Acquisition") of certain assets in the Williston Basin ("Dunn County") from Hess Bakken Investments II, LLC ("Hess"), see Note 4 to the Interim Financial Statements as well as the material change report dated April 16, 2021 available under Enerplus' SEDAR profile at www.sedar.com and Enerplus' EDGAR profile under Form 6-K at www.sec.gov.

OVERVIEW

Global economies have begun to recover from the impacts brought on by the coronavirus ("COVID-19") pandemic and demand for crude oil improved significantly during the second quarter of 2021. This resulted in higher crude oil prices and improved market sentiment.

During the first half of 2021, we completed two acquisitions, which we expect will provide meaningful free cash flow and core inventory, while increasing the scope and scale of our business. The Bruin Acquisition was completed on March 10, 2021, for total cash consideration of US$465 million, subject to certain purchase price adjustments. The Bruin Acquisition was funded by a new three-year US$400 million term loan and through a portion of the proceeds of a bought deal public offering of common shares, which was completed on February 3, 2021. On April 30, 2021, we completed the Dunn County Acquisition, where we acquired certain assets in the Williston Basin from Hess for total cash consideration of US$312 million, subject to customary purchase price adjustments. The Dunn County Acquisition was funded using our existing cash balance and drawing on our sustainability linked bank credit facility ("Bank Credit Facility" or "SLL Credit Facility").

During the second quarter of 2021, the Board of Directors approved a 10% increase to the dividend to $0.033 per share paid quarterly, beginning in June 2021, from $0.01 per share paid monthly previously. Subsequent to the quarter, the Board of Directors approved a 15% increase to the dividend to $0.038 per share, to be paid quarterly, beginning September 2021. We expect to fund the increase through the incremental free cash flow generated by the business.

Production during the second quarter of 2021 averaged 115,351 BOE/day, an increase of 26% compared to average production of 91,671 BOE/day in the first quarter of 2021, and crude oil and natural gas liquids production increased by 46% over the same period. The increase in production was primarily due to a full quarter of production from the Bruin Acquisition and a two month contribution from the Dunn County Acquisition. The increase was also due to 19 net operated wells coming onstream in North Dakota at the end of the first quarter of 2021 and into the second quarter of 2021. As a result of strong production volumes during the first half of the year, we are revising our average annual production guidance for 2021 to 112,000 to 115,000 BOE/day, including 69,500 to 71,500 bbls/day in crude oil and natural gas liquids, from 111,000 to 115,000 BOE/day, including 68,500 to 71,500 bbls/day of crude oil and natural gas liquids.

Capital spending during the second quarter of 2021 totaled $129.9 million, compared to $65.5 million during the first quarter of 2021. The majority of the spending was focused on our U.S. crude oil properties. During the second quarter, we reinitiated our drilling program and continued our completion program in North Dakota. We continue to expect capital spending for 2021 to range between $360 to $400 million.

Our realized Bakken crude oil price differential narrowed to average US$2.76/bbl below WTI during the second quarter of 2021 compared to US$3.12/bbl below WTI during the first quarter of 2021. Bakken differentials in North Dakota were supported by increased demand in both the Midwest and U.S. Gulf coast refining markets. With increased certainty of the continued operation of the Dakota Access Pipeline ("DAPL") and with additional capacity to sell crude oil at U.S. Gulf coast prices due to the expansion of DAPL, we are narrowing our annual Bakken crude oil price differential to average US$2.35/bbl below WTI from US$3.25/bbl below WTI for 2021.

Our realized Marcellus natural gas price differential widened to average US$0.89/Mcf below NYMEX in the second quarter of 2021, compared to US$0.15/Mcf below NYMEX during the first quarter of 2021. As a result of ongoing pipeline maintenance activity in the region, we expect differentials to be wider and have adjusted our annual Marcellus natural gas price differential to average US$0.65/Mcf below NYMEX from US$0.55/Mcf below NYMEX for 2021.

Operating costs for the second quarter of 2021 increased to $88.5 million or $8.43/BOE, compared to $64.5 million or $7.82/BOE, during the first quarter of 2021. This increase was primarily due to higher U.S. crude oil production as a result of the Bruin and Dunn County acquisitions. We continue to expect operating expenses to average $8.25/BOE, during 2021.

We reported a net loss of $59.7 million in the second quarter of 2021 compared to net income of $14.7 million in the first quarter of 2021. The net loss recognized in the second quarter of 2021 was primarily due to a larger commodity derivative instrument loss as a result of significantly higher commodity prices. This was offset by higher crude oil and natural gas liquids revenue as a result of higher production and realized prices.

Cash flow from operations increased to $136.9 million in the second quarter of 2021, compared to $37.2 million in the first quarter of 2021, primarily due to higher realized prices and production. Second quarter adjusted funds flow increased to $184.3 million from $128.0 million over the same period. The increase was primarily due to higher production and an improvement in commodity prices during the quarter.

During the quarter, we increased and extended our senior unsecured Bank Credit Facility to US$900 million from US$600 million with a maturity of October 31, 2025. In addition, we transitioned the facility to a sustainability-linked credit facility with three sustainability-linked performance targets, which reduce or increase our borrowing costs by up to 5 bps as the targets are exceeded or missed.

At June 30, 2021, our total debt net of cash was $1,132.8 million, comprised of senior notes, Bank Credit Facility and the term loan totaling $1,208.1 million, less cash on hand of $75.3 million. Our net debt to adjusted funds flow ratio was 2.3x, which does not include the trailing adjusted funds flow associated with the Bruin and Dunn County acquisitions.

Subsequent to June 30, 2021, we received approval from the Board of Directors to commence a Normal Course Issuer Bid ("NCIB") to purchase up to 10% of the public float (within the meaning under Toronto Stock Exchange ("TSX") rules) during a 12-month period. The NCIB remains subject to approval by the TSX.

RESULTS OF OPERATIONS

Production

Daily production for the second quarter of 2021 averaged 115,351 BOE/day, an increase of 26% compared to average production of 91,671 BOE/day in the first quarter of 2021, with crude oil and natural gas liquids production increasing by 46% to 71,693 bbls/day over the same period. The increase is primarily the result of a full quarter of production from the Bruin assets and a two month contribution from the Dunn County Acquisition. In addition, 19 net operated wells came onstream in North Dakota.

Natural gas production increased slightly to 261,945 Mcf/day, compared to 255,749 Mcf/day in the first quarter of 2021, due to additional natural gas production from the Bruin and Dunn County assets, partially offset by a 6% decrease in production in the Marcellus with less onstream activity in the second quarter of 2021.

For the three months ended June 30, 2021, total production increased by 32% when compared to the same period in 2020. The increase in production was primarily due to a full quarter of production from Bruin's assets and a two-month contribution of the Dunn County assets in the second quarter of 2021. Production for the three months ended June 30, 2020 was impacted by the temporary curtailment of certain crude oil and natural gas liquids production, and the suspension of our operated North Dakota drilling and completions program during the second quarter of 2020, in response to the significant decline in crude oil prices with the onset of the COVID-19 pandemic.

For the six months ended June 30, 2021, total production increased by 12% compared to the same period in 2020. The increase was mainly due to additional production from the Bruin and Dunn County assets during the first half of 2021. Production for the six months ended June 30, 2020 was also impacted by a 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.

Our crude oil and natural gas liquids weighting for the three and six months ended June 30, 2021 increased to 62% and 58%, respectively, from 55% for each of the same periods in 2020.

Average daily production volumes for the three and six months ended June 30, 2021 and 2020 are outlined below:

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2021**	**2020**	**% Change**	**2021**	**2020**	**% Change**
Tight oil (bbls/day)	54,797	37,102	48%	45,090	39,155	15%
Heavy oil (bbls/day)	4,008	2,912	38%	4,063	3,634	12%
Light and medium oil (bbls/day)	2,998	3,154	(5)%	3,034	3,317	(9)%
Total crude oil (bbls/day)	61,803	43,168	43%	52,187	46,106	13%
Natural gas liquids (bbls/day)	9,890	4,929	101%	8,245	5,137	61%
Shale gas (Mcf/day)	254,556	223,460	14%	250,396	235,862	6%
Conventional natural gas (Mcf/day)	7,389	12,119	(39)%	8,467	13,384	(37)%
Total natural gas (Mcf/day)	261,945	235,579	11%	258,863	249,246	4%
Total daily sales (BOE/day)	115,351	87,360	32%	103,576	92,784	12%

As a result of strong production volumes during the first half of the year, we are revising our average annual production guidance for 2021 to 112,000 to 115,000 BOE/day, including 69,500 to 71,500 bbls/day in crude oil and natural gas liquids, from 111,000 to 115,000 BOE/day, including 68,500 to 71,500 bbls/day of crude oil and natural gas liquids.

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 benchmark prices, selling prices and differentials:

Pricing (average for the period)	Six months ended June 30, 2021	Six months ended June 30, 2020	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020
Benchmarks							
WTI crude oil (US$/bbl)	$ 61.96	$ 37.01	$ 66.07	$ 57.84	$ 42.66	$ 40.93	$ 27.85
Brent (ICE) crude oil (US$/bbl)	65.06	42.12	69.02	61.10	45.24	43.37	33.27
NYMEX natural gas – last day (US$/Mcf)	2.76	1.83	2.83	2.69	2.66	1.98	1.72
USD/CDN average exchange rate	1.25	1.37	1.23	1.27	1.30	1.33	1.39
USD/CDN period end exchange rate	1.24	1.36	1.24	1.26	1.27	1.33	1.36
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 72.90	$ 41.59	$ 76.67	$ 67.34	$ 47.95	$ 46.43	$ 30.55
Natural gas liquids ($/bbl)	28.06	6.16	22.72	36.17	17.19	10.60	(0.96)
Natural gas ($/Mcf)	2.96	1.87	2.45	3.48	2.04	1.72	1.63
Average differentials							
Bakken DAPL – WTI (US$/bbl)	$ (1.51)	$ (5.29)	$ (0.40)	$ (2.63)	$ (3.45)	$ (3.40)	$ (5.24)
Brent (ICE) – WTI (US$/bbl)	3.10	5.11	2.95	3.26	2.58	2.44	5.42
MSW Edmonton – WTI (US$/bbl)	(3.11)	(6.86)	(4.18)	(5.24)	(3.91)	(3.51)	(6.14)
WCS Hardisty – WTI (US$/bbl)	(11.98)	(16.00)	(11.49)	(12.47)	(9.30)	(9.08)	(11.47)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.87)	(0.41)	(1.17)	(0.58)	(1.24)	(0.80)	(0.45)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	(0.28)	0.16	(0.72)	0.17	(0.83)	(0.56)	(0.37)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI (US$/bbl)	$ (2.91)	$ (4.87)	$ (2.76)	$ (3.12)	$ (4.82)	$ (5.37)	$ (4.36)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.51)	(0.44)	(0.89)	(0.15)	(1.07)	(0.72)	(0.49)
Canada crude oil – WTI (US$/bbl)	(12.17)	(16.34)	(11.46)	(12.89)	(10.18)	(9.74)	(14.49)

(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

During the second quarter of 2021, our realized crude oil sales price averaged $76.67/bbl, an increase of 14% compared to the first quarter of 2021 and consistent with the increase in the benchmark WTI price over the same period. In the U.S., crude oil prices and price differentials strengthened as refinery demand increased due to improving market conditions in developed nations with the easing of COVID-19 restrictions. Oil supply continues to be managed through the agreement made by the Organization of the Petroleum Exporting Countries Plus (“OPEC+”) nations to curtail production from the market through the end of 2022.

Our realized Bakken crude oil price differential averaged US$2.76/bbl below WTI during the second quarter of 2021 compared to US$3.12/bbl below WTI during the first quarter of 2021. Bakken differentials in North Dakota were supported by increased demand in both the Midwest and U.S. Gulf coast refining markets, as well as excess pipeline capacity within the basin.

Our Bakken crude oil sales portfolio consists of a combination of in-basin monthly spot and index sales, term physical sales with fixed differential pricing versus WTI, sales at Cushing, and sales at the U.S. Gulf Coast delivered via firm capacity on DAPL. Effective August 1, 2021, we increased our committed capacity to deliver crude oil from North Dakota to the U.S. Gulf coast via DAPL as a part of its broader system expansion (see “Transportation Expense” in this MD&A). As a result of the additional DAPL transportation and year to date realized pricing, we are narrowing our guidance for our annual Bakken realized crude oil sales price differential to average approximately US$2.35/bbl below WTI in 2021, from US$3.25/bbl below WTI.

Our realized Canadian crude oil price differential narrowed by 11% compared to the first quarter of 2021, which was in line with changes to the underlying benchmark prices.

Our realized sales price for natural gas liquids averaged $22.72/bbl during the second quarter of 2021, compared to $36.17/bbl in the first quarter of 2021. Natural gas liquids prices normalized during the second quarter after they benefited from the cold weather event in February 2021, which was centered over key natural gas liquids pricing hubs in both the Midwest and Texas.

NATURAL GAS

Our realized natural gas sales price averaged $2.45/Mcf during the second quarter of 2021, a decrease of 30% compared to the first quarter of 2021. Although the NYMEX benchmark price increased by 5% over the same period, Marcellus basin pricing weakened considerably during the quarter due to maintenance activities on regional pipeline systems, and the normal seasonality in pricing we see in the U.S. Northeast during the second quarter.

The lower regional pricing in the Marcellus resulted in our realized Marcellus sales price differential widening to average US$0.89/Mcf below NYMEX during the quarter compared to US$0.15/Mcf below NYMEX in the first quarter of 2021. As a result of ongoing maintenance in the near term, we expect continued weakness in regional price differentials, and, as a result, we are widening our Marcellus differential to average US$0.65/Mcf below NYMEX for 2021, from US$0.55/Mcf below NYMEX.

FOREIGN EXCHANGE

Our crude 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 stronger Canadian dollar decreases the amount of our realized sales as well as the amount of our U.S. denominated costs, such as capital, the interest on our U.S. denominated debt, and the value of our outstanding U.S. senior notes, term loan and LIBOR based borrowing on our Bank Credit Facility.

The Canadian dollar strengthened significantly during the first six months of 2021 in response to higher commodity prices as global economies continued to stabilize and crude oil demand continued to recover from the onset of the COVID-19 pandemic in the first quarter of 2020. The Canadian dollar exchange rate to U.S. dollar ("USD") was 1.24 USD/CDN at June 30, 2021, compared to 1.27 USD/CDN at December 31, 2020. The average exchange rate of 1.25 USD/CDN for the six months ended June 30, 2021 was considerably stronger than the same period in 2020 when it averaged 1.37 USD/CDN.

Price Risk Management

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

We continue to expect our hedging contracts to protect a portion of our cash flow from operating activities and adjusted funds flow. As of August 4, 2021, we have hedged 31,500 bbls/day of crude oil for the remainder of 2021 and 20,800 bbls/day during 2022. We have also hedged 100,000 Mcf/day of natural gas for the period of July 1, 2021 to October 31, 2021 and 40,000 Mcf/day for the period of November 1, 2021 to March 31, 2022. Our crude oil contracts consist of swaps and three way collars. The three way collars provide us with exposure to upward price movement; however, the sold put effectively limits the amount of downside protection we have to the difference between the strike price of the purchased and sold puts.

The following is a summary of our financial contracts in place at August 4, 2021:

	WTI Crude Oil (1)(2) (US$/bbl)				NYMEX Natural Gas (US$/Mcf)	
	Jul 1, 2021 – Dec 31, 2021	Jan 1, 2022 – Dec 31, 2022	Jan 1, 2023 – Oct 31, 2023	Nov 1, 2023 – Dec 31, 2023	Jul 1, 2021 – Oct 31, 2021	Nov 1, 2021 – Mar 31, 2022
Swaps						
Volume (bbls/day)	–	–	–	–	60,000	–
Sold Swaps	–	–	–	–	$ 2.90	–
Collars						
Volume (bbls/day)	23,000	17,000	–	–	40,000	40,000
Sold Puts	$ 36.39	$ 40.00	–	–	$ 2.15	–
Purchased Puts	$ 46.39	$ 50.00	–	–	$ 2.75	$ 3.43
Sold Calls	$ 56.70	$ 57.91	–	–	$ 3.25	$ 6.00
Hedges acquired from Bruin(3)						
Swaps						
Volume (bbls/day)	8,465	3,828	250	–	–	–
Sold Swaps	$ 42.52	$ 42.35	$ 42.10	–	–	–
Collars						
Volume (bbls/day)	–	–	2,000	2,000	–	–
Purchased Puts	–	–	$ 5.00	$ 5.00	–	–
Sold Calls	–	–	$ 75.00	$ 75.00	–	–

(1) The total average deferred premium spent on our outstanding crude oil contracts is US$0.84/bbl from July 1, 2021 - December 31, 2021 and US$1.22/bbl from January 1, 2022 - December 31, 2022.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Upon closing of the Bruin Acquisition, Bruin's outstanding crude oil contracts were recorded at a fair value liability of $96.5 million. At June 30, 2021, the balance was a liability of $64.5 million on the Condensed Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired contracts are recognized in Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the date of closing of the Bruin Acquisition. See Note 17 to the Interim Financial Statements for further details.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	Three months ended June 30,		Six months ended June 30,	
($ millions)	2021	2020	2021	2020
Cash gains/(losses):				
Crude oil	$ (37.9)	$ 53.5	$ (58.0)	$ 86.5
Natural gas	0.7	—	1.4	—
Total cash gains/(losses)	$ (37.2)	$ 53.5	$ (56.6)	$ 86.5
Non-cash gains/(losses):				
Crude oil	$ (146.9)	$ (64.4)	$ (198.5)	$ 33.9
Natural gas	(13.9)	—	(12.7)	—
Total non-cash gains/(losses)	$ (160.8)	$ (64.4)	$ (211.2)	$ 33.9
Total gains/(losses)	$ (198.0)	$ (10.9)	$ (267.8)	$ 120.4

	Three months ended June 30,		Six months ended June 30,	
(Per BOE)	2021	2020	2021	2020
Total cash gains/(losses)	$ (3.53)	$ 6.73	$ (3.02)	$ 5.12
Total non-cash gains/(losses)	(15.32)	(8.10)	(11.27)	2.01
Total gains/(losses)	$ (18.85)	$ (1.37)	$ (14.29)	$ 7.13

We realized cash losses of $37.9 million and $58.0 million, respectively, on our crude oil contracts during the three and six months ended June 30, 2021, compared to realized cash gains of $53.5 million and $86.5 million for the same periods in 2020. We recorded realized cash gains of $0.7 million and $1.4 million, respectively, on our natural gas contracts in the three and six months ended June 30, 2021 and there were no natural gas derivative contracts outstanding during the same periods in 2020.

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, 2021, the fair value of our crude oil and natural gas contracts was in a net liability position of $287.9 million. For the three and six months ended June 30, 2021, the change in the fair value of our crude oil contracts resulted in an unrealized loss of $146.9 million and $198.5 million, respectively, compared to a loss of $64.4 million and a gain of $ 33.9 million, respectively, during the same periods in 2020. We recorded unrealized losses on our natural gas contracts of $13.9 million and $12.7 million, respectively, for the three and six months ended June 30, 2021.

On March 10, 2021, the outstanding crude oil contracts acquired with the Bruin Acquisition were recorded at fair value, resulting in a liability of $96.5 million on the Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired contracts are recognized in Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the closing date of the Bruin Acquisition. At June 30, 2021, the fair value of the Bruin contracts was a liability of $99.9 million, including $64.5 million of the original $96.5 million liability acquired. For the three and six months ended June 30, 2021 we recorded a realized loss of $2.2 million and $1.7 million, respectively, on the settlement of the Bruin contracts. In addition, we recognized an unrealized loss of $52.8 million and $35.4 million, respectively, for the change in the fair value of the Bruin contracts over the same periods. See Note 17 to the Interim Financial Statements for further detail.

Revenues

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2021	2020	2021	2020
Crude oil and natural gas sales	$ 510.2	$ 155.3	$ 869.5	$ 440.9
Royalties	(101.6)	(33.2)	(172.1)	(90.7)
Crude oil and natural gas sales, net of royalties	$ 408.6	$ 122.1	$ 697.4	$ 350.2

Crude oil and natural gas sales, net of royalties, for the three and six months ended June 30, 2021 were $408.6 million and $697.4 million, respectively, compared to $122.1 million and $350.2 million, from the same periods in 2020. The increase in revenue was primarily due to higher production as a result of the Bruin and Dunn County acquisitions in 2021 and higher realized prices. Revenues in 2020 were impacted by lower realized prices as a result of the demand destruction from the COVID-19 pandemic and the Saudi Arabia and Russian price war, along with price related production curtailments.

Royalties and Production Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2021	2020	2021	2020
Royalties	$ 101.6	$ 33.2	$ 172.1	$ 90.7
Per BOE	$ 9.68	$ 4.18	$ 9.18	$ 5.37
Production taxes	$ 30.5	$ 7.7	$ 48.0	$ 23.1
Per BOE	$ 2.90	$ 0.97	$ 2.56	$ 1.37
Royalties and production taxes	$ 132.1	$ 40.9	$ 220.1	$ 113.8
Per BOE	$ 12.58	$ 5.15	$ 11.74	$ 6.74
Royalties and production taxes (% of crude oil and natural gas sales)	25.9%	26.3%	25.3%	25.8%

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. Royalties and production taxes for the three and six months ended June 30, 2021, were $132.1 million and $220.1 million, respectively, compared to $40.9 million and $113.8 million from the same periods in 2020. Total royalties increased due to higher realized prices and higher production volumes, compared to lower realized prices and lower production volumes during the comparative periods in 2020.

We continue to expect annual royalties and production taxes in 2021 to average 26% of crude oil and natural gas sales before transportation.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended June 30, 2021	2020	Six months ended June 30, 2021	2020
Operating expenses	$ 88.5	$ 54.4	$ 153.0	$ 133.4
Per BOE	$ 8.43	$ 6.84	$ 8.16	$ 7.90

For the three and six months ended June 30, 2021, operating expenses were $88.5 million or $8.43/BOE and $153.0 million or $8.16/BOE, respectively, compared to $54.4 million or $6.84/BOE and $133.4 million or $7.90/BOE, for the same periods in 2020. This increase was primarily due to higher U.S. crude oil production, as a result of the Bruin and Dunn County acquisitions and increased liquids weighting, partially offset by a stronger Canadian dollar in 2021. Operating expenses were lower during the three and six months ended June 30, 2020 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.

We continue to expect operating expenses of $8.25/BOE in 2021.

Transportation Expenses

($ millions, except per BOE amounts)	Three months ended June 30, 2021	2020	Six months ended June 30, 2021	2020
Transportation expenses	$ 36.2	$ 34.0	$ 69.0	$ 69.3
Per BOE	$ 3.45	$ 4.28	$ 3.68	$ 4.11

For the three and six months ended June 30, 2021, transportation expenses were $36.2 million or $3.45/BOE and $69.0 million or $3.68/BOE, respectively, compared to $34.0 million or $4.28/BOE and $69.3 million or $4.11/BOE, for the same periods in 2020. Transportation expenses decreased on a per BOE basis for both the three and six months periods ended June 30, 2021 compared to the same periods in 2020, primarily due to the impact of a stronger Canadian dollar on our U.S. dollar denominated transportation costs.

Effective August 1, 2021, Enerplus participated in the DAPL expansion with an additional 6,500 bbls/day of firm crude oil transportation. The additional transportation provides access to sell a greater portion of our production at U.S. Gulf Coast or Brent pricing.

We continue to expect transportation expenses of $3.85/BOE in 2021.

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, 2021		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	81,934 BOE/day	200,503 Mcfe/day	115,351 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 62.51	$ 2.42	$ 48.60
Royalties and production taxes	(16.49)	(0.50)	(12.58)
Operating expenses	(11.47)	(0.16)	(8.43)
Transportation expenses	(2.64)	(0.91)	(3.45)
Netback before hedging	$ 31.91	$ 0.85	$ 24.14
Cash hedging gains/(losses)	(5.08)	0.04	(3.53)
Netback after hedging	$ 26.83	$ 0.89	$ 20.61
Netback before hedging ($ millions)	$ 237.9	$ 15.5	$ 253.4
Netback after hedging ($ millions)	$ 200.0	$ 16.2	$ 216.2

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

Netbacks by Property Type	Three months ended June 30, 2020 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)
Crude oil and natural gas sales	$ 25.63	$ 1.75	$ 19.53
Royalties and production taxes	(7.18)	(0.35)	(5.15)
Operating expenses	(10.45)	(0.25)	(6.84)
Transportation expenses	(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

Netbacks by Property Type	Six months ended June 30, 2021 Crude Oil	Natural Gas	Total
Average Daily Production	68,876 BOE/day	208,199 Mcfe/day	103,576 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 61.09	$ 2.86	$ 46.38
Royalties and production taxes	(15.92)	(0.57)	(11.74)
Operating expenses	(11.75)	(0.17)	(8.16)
Transportation expenses	(2.81)	(0.90)	(3.68)
Netback before hedging	$ 30.61	$ 1.22	$ 22.80
Cash hedging gains/(losses)	(4.65)	0.04	(3.02)
Netback after hedging	$ 25.96	$ 1.26	$ 19.78
Netback before hedging ($ millions)	$ 381.6	$ 45.8	$ 427.4
Netback after hedging ($ millions)	$ 323.6	$ 47.2	$ 370.8

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)
Crude oil and natural gas sales	$ 35.63	$ 1.96	$ 26.11
Royalties and production taxes	(9.71)	(0.38)	(6.74)
Operating expenses	(11.99)	(0.29)	(7.90)
Transportation expenses	(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

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

Total netbacks before and after hedging for the three and six months ended June 30, 2021, were higher compared to the same periods in 2020, primarily due to higher realized prices and higher production.

For the three months ended June 30, 2021, our crude oil properties accounted for 94% and 89%, respectively, of our total netback before hedging, compared to 87% and 89% during the same period in 2020.

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 13 and Note 16(b) to the Interim Financial Statements for further details.

($ millions)	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Cash:				
G&A expenses	$ 10.9	$ 9.1	$ 24.0	$ 21.5
Share-based compensation expense	2.3	1.2	5.1	(1.6)
Non-Cash:				
Share-based compensation expense	0.1	3.6	1.2	11.3
Equity swap loss/(gain)	(0.7)	(0.5)	(1.3)	1.4
G&A expenses	(0.1)	0.1	(0.2)	0.1
Total G&A expenses	$ 12.5	$ 13.5	$ 28.8	$ 32.7

(Per BOE)	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Cash:				
G&A expenses	$ 1.04	$ 1.14	$ 1.28	$ 1.26
Share-based compensation expense	0.22	0.15	0.27	(0.09)
Non-Cash:				
Share-based compensation expense	0.01	0.45	0.06	0.67
Equity swap loss/(gain)	(0.07)	(0.06)	(0.07)	0.08
G&A expenses	(0.01)	0.01	(0.01)	0.01
Total G&A expenses	$ 1.19	$ 1.69	$ 1.53	$ 1.93

Cash G&A expenses for the three and six months ended June 30, 2021, were $10.9 million or $1.04/BOE and $24.0 million or $1.28/BOE, respectively, compared to $9.1 million or $1.14/BOE and $21.5 million or $1.26/BOE for the same periods in 2020. Cash G&A expenses were higher compared to the same periods in 2020 due to government funding received related to the second quarter of 2020, during the height of the COVID-19 pandemic, which reimbursed qualifying Canadian employers for a portion of salaries paid. Cash G&A on a per BOE basis decreased compared to the three months ended June 30, 2021, due to higher production in the second quarter of 2021.

Cash SBC expenses for the three and six months ended June 30, 2021, were $2.3 million and $5.1 million, respectively, compared to an expense of $1.2 million and a recovery of $1.6 million, respectively, for the same periods in 2020. The higher expense was due to the increase in our share price on our outstanding Director Deferred Share Units. Non-cash SBC expense for the three and six months ended June 30, 2021 were $0.1 million or $0.01/BOE and $1.2 million or $0.06/BOE, respectively, compared to $3.6 million or $0.45/BOE and $11.3 million or $0.67/BOE, respectively for the same periods in 2020. The decrease in non-cash SBC expense was the result of lower performance multipliers on our outstanding Performance Share Units ("PSUs").

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. During the three and six months ended June 30, 2021, we recorded a mark-to-market gain of $0.7 million and $1.3 million, as a result of the increase in our share price.

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

Interest Expense

For the three months and six months ended June 30, 2021, we recorded total interest expense of $9.5 million and $16.4 million, respectively, compared to $7.1 million and $16.0 million, respectively, for the same periods in 2020. The increase was primarily due to increased debt levels used to fund the Bruin and Dunn County acquisitions. The increase was partially offset by the final repayment of our 2009 senior notes and the partial repayment of our 2012 senior notes during the second quarter of 2021, which carry higher interest rates than our Bank Credit Facility as well as the strengthening of the Canadian dollar on our U.S. dollar denominated interest expense.

At June 30, 2021, approximately 31% of our debt was based on fixed interest rates and 69% on floating interest rates (December 31, 2020 – 100% fixed), with weighted average interest rates of 4.4% and 1.9%, respectively (December 31, 2020 – 4.4%). See Note 9 to the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Realized foreign exchange (gain)/loss:				
Foreign exchange (gain)/loss on settlements	$ 3.8	$ 0.1	$ 3.1	$ —
Translation of U.S. dollar cash held in Canada (gain)/loss	(2.4)	0.4	(2.0)	(2.7)
Unrealized foreign exchange (gain)/loss	5.5	1.0	5.9	(1.4)
Total foreign exchange (gain)/loss	$ 6.9	$ 1.5	$ 7.0	$ (4.1)
USD/CDN average exchange rate	1.23	1.39	1.25	1.37
USD/CDN period end exchange rate	1.24	1.36	1.24	1.36

For the three and six months ended June 30, 2021, we recorded a foreign exchange loss of $6.9 million and $7.0 million, respectively, compared to a loss of $1.5 million and a gain of $4.1 million, respectively, for the same periods in 2020. Realized foreign exchange gains and losses relate primarily to day-to-day transactions recorded in foreign currencies and 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 Credit Facility and working capital held in Canada at each period end.

At June 30, 2021, US$303.8 million of senior notes outstanding and the US$400 million term loan were designated as net investment hedges. For the three and six months ended June 30, 2021, Other Comprehensive Income/(Loss) included an unrealized gain of $14.7 million and $23.2 million, respectively, on our U.S. dollar denominated senior notes and term loan compared to an unrealized gain of $19.5 million and an unrealized loss of $30.6 million, respectively for the same periods in 2020.

Capital Investment

($ millions)	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Capital spending[1]	$ 129.9	$ 40.1	$ 195.4	$ 203.7
Office capital[1]	0.5	0.9	0.9	2.8
Sub-total	130.4	41.0	196.3	206.5
Property and land acquisitions	$ 1.7	$ 3.4	$ 5.1	$ 5.7
Bruin Acquisition	32.3	—	657.5	—
Dunn County Acquisition	374.8	—	374.8	—
Property divestments	—	0.1	(5.0)	(5.5)
Sub-total	408.8	3.5	1,032.4	0.2
Total	$ 539.2	$ 44.5	$ 1,228.7	$ 206.7

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

Capital spending for the three and six months ended June 30, 2021 totaled $129.9 million and $195.4 million, respectively, compared to $40.1 million and $203.7 million, respectively, for the same periods in 2020. The increase is mainly due to the suspension of operated drilling and completions activity in North Dakota during the second quarter of 2020 and the start of the 2021 capital program in early March. Capital spending during the second quarter of 2021 included $116.8 million on our U.S. crude oil properties, $8.7 million on our Marcellus natural gas assets and $4.4 million on our Canadian waterflood properties.

On April 30, 2021, we completed the Dunn County Acquisition for total cash consideration of $376.9 million, with $374.8 million allocated to PP&E, excluding the assumed asset retirement obligation.

During the six months ended June 30, 2021, we completed the Bruin Acquisition for total cash consideration of $531.1 million, with $657.5 million allocated to PP&E, excluding the assumed asset retirement obligation.

We continue to expect our capital spending for 2021 to range between $360 to $400 million.

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

($ millions, except per BOE amounts)	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
DD&A expense	$ 93.9	$ 79.9	$ 140.4	$ 175.1
Per BOE	$ 8.95	$ 10.05	$ 7.49	$ 10.37

DD&A related to PP&E is recognized using the unit-of-production method based on proved reserves. For the three and six months ended June 30, 2021, we recorded DD&A expense of $93.9 million and $140.4 million, respectively, compared to $79.9 million and $175.1 million, respectively, for the same periods in 2020. DD&A expense on a per BOE basis decreased compared to the same periods in 2020 mainly due to the impact of previous PP&E impairments.

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 a prescribed 10 percent rate based on 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 7(a) to the Interim Financial Statements for trailing twelve month prices.

Trailing twelve month average crude oil and natural gas prices declined throughout 2020 and have improved throughout 2021. For the three and six months ended June 30, 2021, we recorded a non-cash PP&E impairment of nil and $4.3 million, respectively, related to our Canadian assets. 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).

We requested and received a temporary exemption from the SEC to exclude the properties acquired in the Bruin Acquisition in the U.S. full cost ceiling test, for each quarter of 2021. See Note 7(b) to the Interim Financial Statements for further details.

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 2021, the primary factors include future first-day-of-the-month commodity prices, reserves revisions, capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. See "Risk Factors and Risk Management - Risk of Impairment of Oil and Gas Properties and Deferred Tax Assets" in the Annual MD&A.

Goodwill

During the second quarter of 2020, we recorded a non-cash goodwill impairment 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-off of our U.S. goodwill asset. At June 30, 2021, there was no goodwill remaining on our Condensed Consolidated Balance Sheet.

Asset Retirement Obligation ("ARO")

In connection with our operations, we incur abandonment, reclamation and remediation costs related to assets, such as surface leases, wells, facilities and pipelines. Total ARO included on the Condensed Consolidated Balance Sheet is based on management's estimate of our net ownership interest, costs to abandon, reclaim and remediate 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 5.05%, to be $160.2 million at June 30, 2021, compared to $130.2 million at December 31, 2020, using a weighted average credit-adjusted risk-free rate of 5.35%. The increase in the net present value of our asset retirement obligation to June 30, 2021 is largely due to $35.0 million of additional liability assumed in connection with the Bruin and Dunn County acquisitions. For the three and six months ended June 30, 2021, asset retirement obligation settlements were $1.4 million and $8.4 million, respectively, compared to $0.3 million and $11.1 million, respectively, during the same periods in 2020.

In 2021, Enerplus benefited from provincial government assistance to support the cleanup of inactive or abandoned crude oil and natural gas wells in Canada. These programs provide funding directly to oil field service contractors engaged by Enerplus to perform abandonment, remediation, and reclamation work. The funding received by the contractor is reflected as a reduction to ARO. For the six months ended June 30, 2021, Enerplus benefitted from $2.4 million in government assistance. See Note 3 and 10 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, 2021, our total lease liability was $40.6 million (December 31, 2020 - $36.8 million). In addition, ROU assets of $37.0 million were recorded, which equate to our lease liabilities less lease incentives (December 31, 2020 - $32.9 million). See Note 11 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2021	2020	2021	2020
Current tax expense/(recovery)	$ 4.2	$ (14.4)	$ 4.2	$ (14.4)
Deferred tax expense/(recovery)	(11.1)	(98.9)	(0.1)	10.4
Total tax expense/(recovery)	$ (6.9)	$ (113.3)	$ 4.1	$ (4.0)

For the three and six months ended June 30, 2021, we recorded a current tax expense of $4.2 million compared to a recovery of $14.4 million in 2020. The current tax expense in the second quarter primarily consists of U.S. Federal tax as a result of higher income in the U.S. in 2021. The recovery in 2020 relates to the final U.S. Alternative Minimum Tax ("AMT") refund.

We expect current tax expense of between US$5.0 to US$7.0 million in 2021.

For the three and six months ended June 30, 2021, we recorded deferred income tax recoveries of $11.1 million and $0.1 million respectively, compared to a recovery of $98.9 million and an expense of $10.4 million for the same periods in 2020. The deferred tax recovery in the second quarter was primarily due to the non-cash commodity derivative losses partially offset by higher U.S. income in 2021. The deferred tax recovery in 2020 was primarily due to 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. There is a risk of a valuation allowance in future periods if commodity prices weaken or other evidence indicates that some of our deferred income tax assets will not be realized. See "Risk Factors and Risk Management - Risk of Impairment of Oil and Gas Properties and Deferred Tax Assets" in the Annual MD&A. For the six months ended June 30, 2021, no valuation allowance was recorded against our U.S. and Canadian income related deferred income tax assets, however, a full valuation allowance has been recorded against our deferred income tax assets related to capital items. Our overall net deferred income tax asset was $600.3 million at June 30, 2021 (December 31, 2020 - $607.0 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, term loan 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, 2021, our senior debt to adjusted EBITDA ratio was 2.0x and our net debt to adjusted funds flow ratio was 2.3x, which does not include the trailing adjusted funds flow associated with the Bruin and Dunn County acquisitions. 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. Refer to the definitions and footnotes below.

Total debt net of cash at June 30, 2021 increased to $1,132.8 million, compared to $376.0 million at December 31, 2020. Total debt was comprised of our senior notes, term loan and Bank Credit Facility, totaling $1,208.1 million, less cash on hand of $75.3 million. The increase was due to funding a portion of the Bruin Acquisition using a US$400 million term loan and funding the Dunn County Acquisition by drawing on our Bank Credit Facility and cash on hand.

During the second quarter of 2021, Enerplus made its final US$22.0 million principal repayment on its 2009 senior notes and its second US$59.6 million principal repayment on its 2012 senior notes, using the Bank Credit Facility. This resulted in a $99.3 million decrease to our outstanding senior notes at June 30, 2021, compared to December 31, 2020.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by adjusted funds flow, was 77% and 69%, respectively, for the three and six months ended June 30, 2021, compared to 68% and 120% for the same periods in 2020.

During the second quarter of 2021, the Board of Directors approved a 10% increase to the dividend to $0.033 per share paid quarterly, beginning in June, from $0.01 per share paid monthly previously. Subsequent to the quarter, the Board of Directors approved a 15% increase to the dividend to $0.038 per share, to be paid quarterly, beginning September 2021. We expect to fund the increase though the incremental free cash flow generated by the business.

Subsequent to June 30, 2021, we received approval from the Board of Directors to commence a NCIB to purchase up to 10% of the public float (within the meaning under TSX rules) during a 12-month period. The NCIB remains subject to approval by the TSX.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, decreased to $231.1 million at June 30, 2021 from $257.8 million at December 31, 2020. Our working capital varies due to the timing of the cash realization of our current assets and current liabilities, and the current level of business activity, including our capital spending program, along with commodity price volatility. We expect to finance our working capital deficit and ongoing working capital requirements through cash, adjusted funds flow and our Bank Credit Facility. We have sufficient liquidity to meet our financial commitments for the near term.

During the second quarter, we increased and extended our senior, unsecured, covenant-based Bank Credit Facility to US$900 million from US$600 million with a maturity of October 31, 2025. As part of the extension, the Company transitioned the facility to a sustainability-linked credit facility incorporating environmental, social and governance (“ESG”)-linked incentive pricing terms which reduce or increase the borrowing costs by up to 5 basis points as Enerplus’ sustainability performance targets (“SPT”) are exceeded or missed. The SPTs are based on the following ESG goals of the Company:

- **GHG Emissions:** continuous progress toward Enerplus’ stated goal of a 50% reduction in corporate Scope 1 and 2 greenhouse gas emissions intensity by 2030, using 2019 as a baseline and measurement based on Enerplus’ annual internal targets;

- **Water Management:** achieve a 50% reduction in freshwater usage in corporate well completions by 2025 or earlier compared to 2019, with progress to be measured on an annual basis over the life of the credit facility; and

- **Health & Safety:** achieve and maintain a 25% reduction in the Company’s Lost Time Injury Frequency, based on a trailing 3-year average, relative to a 2019 baseline.

At June 30, 2021, we were in compliance with all covenants under the Bank Credit Facility, the term loan and outstanding senior notes. If we exceed or anticipate exceeding our covenants, we may be required to repay, refinance or renegotiate the terms of the debt. See "Risk Factors – Debt covenants of the Corporation may be exceeded with no ability to negotiate covenant relief" in the Annual Information Form. Agreements relating to our Bank Credit Facility and term loan and the 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, 2021:

Covenant Description		June 30, 2021
Bank Credit Facility/Term Loan:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	2.0x
Total debt to adjusted EBITDA (1)	4.0x	2.0x
Total debt to capitalization	55%	42%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	2.0x
Senior debt to consolidated present value of total proved reserves(3)	60%	47%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	21.6x

Definitions
"Senior debt" is calculated as the sum of drawn amounts on our Bank Credit Facility, term loan, outstanding letters of credit and the principal amount of senior notes.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, accretion, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended June 30, 2021 was $203.7 million and $621.3 million, respectively.
"Total debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.
"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $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%.Total proved reserves at December 31, 2020 has been updated for reserves acquired through the Bruin and Dunn County Acquisitions.

Dividends

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per share amounts)	2021	2020	2021	2020
Dividends to shareholders(1)	$ 11.0	$ 6.7	$ 18.4	$ 13.3
Per weighted average share (Basic)	$ 0.04	$ 0.03	$ 0.07	$ 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, 2021, we declared total dividends of $11.0 million or $0.04 per share, $18.4 million or $0.07 per share, respectively, compared to $6.7 million or $0.03 per share, or $13.3 million or $0.06 per share, respectively, for the same periods in 2020. The aggregate amount of dividends paid to shareholders has increased compared to the same period in 2020 due to an increase in common shares outstanding as a result of the bought deal equity financing completed in the first quarter of 2021 and an increase to the dividend during the second quarter of 2021.

The Board of Directors approved a 10% increase to the dividend to $0.033 per share paid quarterly beginning in June 2021, from $0.01 per share paid monthly previously. Subsequent to the quarter, the Board of Directors approved a 15% increase to the dividend to $0.038 per share, to be paid quarterly, beginning September 2021. The dividend is part of our strategy to return capital to shareholders. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Six months ended June 30,	
	2021	2020
Share capital ($ millions)	$ 3,236.1	$ 3,097.0
Common shares outstanding (thousands)	256,750	222,548
Weighted average shares outstanding – basic (thousands)	250,443	222,457
Weighted average shares outstanding – diluted (thousands)	250,443	222,457

For the six months ended June 30, 2021, a total of 2,014,193 units vested pursuant to our treasury settled LTI plans, including the impact of performance multipliers (2020 – 2,044,718). In total, 1,140,000 shares were issued from treasury and $11.9 million was transferred from paid-in capital to share capital (2020 – 1,160,000; $13.8 million). We elected to cash settle the remaining units related to the required tax withholdings (2021 – $4.5 million, 2020 – $7.2 million).

During the six months ended June 30, 2021, we issued 33,062,500 common shares at a price of $4.00 per common share for gross proceeds of $132.3 million ($127.2 million net of issue costs less tax) pursuant to a bought deal offering under our base shelf prospectus.

As of August 4, 2021, we had 256,750,100 common shares outstanding. In addition, an aggregate of 10,940,268 common shares may be issued to settle outstanding grants under the PSUs and Restricted Share Unit plans assuming the maximum performance multiplier of 2.0 times for the PSUs.

On June 23, 2021, we filed a short form base shelf prospectus (the "Shelf Prospectus") with securities regulatory authorities in each of the provinces and territories of Canada and a Registration Statement with the U.S. Securities Exchange Commission. The Shelf Prospectus allows us to offer and issue up to an aggregate amount of $2.0 billion of common shares, preferred shares, warrants, subscription receipts and units by way of one or more prospectus supplements during the 25-month period that the Shelf Prospectus remains valid.

Subsequent to June 30, 2021, we received approval from the Board of Directors to commence a NCIB to purchase up to 10% of the public float (within the meaning under TSX rules) during a 12-month period. The NCIB remains subject to approval by the TSX.

For further details, see Note 16 to the Interim Financial Statements.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended June 30, 2021			Three months ended June 30, 2020		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	7,006	54,797	61,803	6,066	37,102	43,168
Natural gas liquids (bbls/day)	447	9,443	9,890	613	4,316	4,929
Natural gas (Mcf/day)	7,584	254,361	261,945	12,315	223,264	235,579
Total average daily production (BOE/day)	8,717	106,634	115,351	8,731	78,629	87,360
Pricing[2]						
Crude oil (per bbl)	$ 66.47	$ 77.98	$ 76.67	$ 19.57	$ 32.35	$ 30.55
Natural gas liquids (per bbl)	40.62	21.88	22.72	15.17	(3.25)	(0.96)
Natural gas (per Mcf)	3.43	2.42	2.45	2.19	1.60	1.63
Capital Investment						
Capital and office expenditures	$ 4.2	$ 125.7	$ 129.9	$ 2.9	$ 37.2	$ 40.1
Acquisitions, including property and land	0.6	408.2	408.8	0.4	3.0	3.4
Property divestments	—	—	—	0.1	—	0.1
Netback[3] Before Hedging						
Crude oil and natural gas sales	$ 46.6	$ 463.6	$ 510.2	$ 14.7	$ 140.6	$ 155.3
Royalties	(10.1)	(91.5)	(101.6)	(1.7)	(31.5)	(33.2)
Production taxes	(0.7)	(29.8)	(30.5)	0.1	(7.8)	(7.7)
Operating expenses	(13.8)	(74.7)	(88.5)	(11.3)	(43.1)	(54.4)
Transportation expenses	(2.0)	(34.2)	(36.2)	(1.7)	(32.3)	(34.0)
Netback before hedging	$ 20.0	$ 233.4	$ 253.4	$ 0.1	$ 25.9	$ 26.0
Other Expenses						
Asset impairment	$ —	$ —	$ —	$ 77.5	$ 349.3	$ 426.8
Goodwill impairment	—	—	—	—	202.8	202.8
Commodity derivative instruments loss/(gain)	198.0	—	198.0	10.9	—	10.9
Total G&A (including SBC)	0.1	12.4	12.5	(0.4)	13.9	13.5
Current income tax expense/(recovery)	—	4.2	4.2	—	(14.4)	(14.4)

(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.

($ millions, except per unit amounts)	Six months ended June 30, 2021 Canada	U.S.	Total	Six months ended June 30, 2020 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	7,098	45,089	52,187	6,951	39,155	46,106
Natural gas liquids (bbls/day)	473	7,772	8,245	661	4,476	5,137
Natural gas (Mcf/day)	8,818	250,045	258,863	13,614	235,632	249,246
Total average daily production (BOE/day)	9,041	94,536	103,576	9,881	82,903	92,784
Pricing[2]						
Crude oil (per bbl)	$ 61.38	$ 74.71	$ 72.90	$ 30.40	$ 43.57	$ 41.59
Natural gas liquids (per bbl)	40.70	27.29	28.06	19.85	4.13	6.16
Natural gas (per Mcf)	3.72	2.93	2.96	2.18	1.85	1.87
Capital Investment						
Capital and office expenditures	$ 9.0	$ 186.4	$ 195.4	$ 14.7	$ 189.0	$ 203.7
Acquisitions, including property and land	1.6	1,035.8	1,037.4	1.5	4.2	5.7
Property divestments	(5.0)	—	(5.0)	0.1	(5.6)	(5.5)
Netback[3] Before Hedging						
Crude oil and natural gas sales	$ 88.7	$ 780.8	$ 869.5	$ 47.5	$ 393.4	$ 440.9
Royalties	(17.7)	(154.4)	(172.1)	(7.4)	(83.3)	(90.7)
Production taxes	(1.2)	(46.8)	(48.0)	(0.2)	(22.9)	(23.1)
Operating expenses	(25.7)	(127.3)	(153.0)	(28.9)	(104.5)	(133.4)
Transportation expenses	(4.1)	(64.9)	(69.0)	(3.8)	(65.5)	(69.3)
Netback before hedging	$ 40.0	$ 387.4	$ 427.4	$ 7.2	$ 117.2	$ 124.4
Other Expenses						
Asset impairment	$ 4.3	$ —	$ 4.3	$ 77.5	$ 349.3	$ 426.8
Goodwill impairment	—	—	—	—	202.8	202.8
Commodity derivative instruments loss/(gain)	267.8	—	267.8	(120.4)	—	(120.4)
Total G&A (including SBC)	6.9	21.9	28.8	(0.6)	33.3	32.7
Current income tax expense/(recovery)	—	4.2	4.2	—	(14.4)	(14.4)

(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.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Crude Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Diluted
2021				
Second Quarter	$ 408.6	$ (59.7)	$ (0.23)	$ (0.23)
First Quarter	288.8	14.7	0.06	0.06
Total 2021	$ 697.4	$ (45.0)	$ (0.18)	$ (0.18)
2020				
Fourth Quarter	$ 195.1	$ (204.2)	$ (0.92)	$ (0.92)
Third Quarter	191.9	(112.8)	(0.51)	(0.51)
Second Quarter	122.1	(609.3)	(2.74)	(2.74)
First Quarter	228.1	2.9	0.01	0.01
Total 2020	$ 737.2	$ (923.4)	$ (4.15)	$ (4.15)
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)

Crude oil and natural gas sales, net of royalties, increased to $408.6 million during the second quarter of 2021 compared to $288.8 million during the first quarter of 2021. The increase in crude oil and natural gas sales, net of royalties, was a result of improved realized pricing and increased production during the second quarter of 2021, when compared to the first quarter of 2021. We reported a net loss of $59.7 million during the second quarter of 2021 compared to net income of $14.7 million during the first quarter of 2021. The net loss in the second quarter of 2021 was primarily due to a $198.0 million loss recorded on commodity derivative instruments, compared to a loss of $69.8 million recorded in the first quarter of 2021.

Crude oil and natural gas sales, net of royalties, decreased in 2020 compared to 2019 due to lower commodity prices, and decreased production due to the COVID-19 pandemic. We reported a net loss in 2020 due to a $994.8 million non-cash PP&E impairment and a $202.8 million non-cash goodwill impairment.

RECENT ACCOUNTING STANDARDS

We have not early adopted any accounting standard, interpretation or amendment that has been issued but is not yet effective. Our significant accounting policies remain unchanged from December 31, 2020, other than as described in Note 3 to the Interim Financial Statements, "Accounting Policy Changes".

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, 2021, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

2021 GUIDANCE

We are revising our average annual production guidance range for 2021 to 112,000 to 115,000 BOE/day including 69,500 to 71,500 bbls/day in crude oil and natural gas liquids, from 111,000 to 115,000 BOE/day including 68,500 to 71,500 bbls/day of crude oil and natural gas liquids.

We are modifying our full year Bakken and Marcellus differential guidance to US$2.35/bbl below WTI and US$0.65/Mcf below NYMEX from US$3.25/bbl below WTI and US$0.55/Mcf below NYMEX.

We are adding guidance for current income tax expense of US$5.0 million to US$7.0 million for 2021.

All other guidance targets remain unchanged.

Summary of 2021 Annual Expectations(1)	Target Annual Results
Capital spending	$360 - $400 million
Average annual production	112,000 - 115,000 BOE/day (from 111,000 - 115,000 BOE/day)
Average annual crude oil and natural gas liquids production	69,500 - 71,500 bbls/day (from 68,500 - 71,500 bbls/day)
Average royalty and production tax rate (% of gross sales, before transportation)	26%
Operating expenses	$8.25/BOE
Transportation costs	$3.85/BOE
Cash G&A expenses	$1.25/BOE
Current Income Tax expense	US$5 - US$7 million

Summary of 2021 Annual Expectations(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)(2)	US$(2.35)/bbl (from US$(3.25)/bbl)
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.65)/Mcf (from US$(0.55)/Mcf)

(1) Excluding transportation costs.
(2) 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 crude oil and natural gas sales less royalties, production taxes, operating expenses and transportation expenses. The cash impact of hedging related to commodity derivative instruments is also analyzed as a part of this calculation.

Calculation of Netback	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2021**	**2020**	**2021**	**2020**
Crude oil and natural gas sales	$ 510.2	$ 155.3	$ 869.5	$ 440.9
Less:				
Royalties	(101.6)	(33.2)	(172.1)	(90.7)
Production taxes	(30.5)	(7.7)	(48.0)	(23.1)
Operating expenses	(88.5)	(54.4)	(153.0)	(133.4)
Transportation expenses	(36.2)	(34.0)	(69.0)	(69.3)
Netback before hedging	$ 253.4	$ 26.0	$ 427.4	$ 124.4
Cash gains/(losses) on commodity derivative instruments	(37.2)	53.5	(56.6)	86.5
Netback after hedging	$ 216.2	$ 79.5	$ 370.8	$ 210.9

"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/(used in) 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)	**2021**	**2020**	**2021**	**2020**
Cash flow from/(used in) operating activities	$ 136.9	$ 90.6	$ 174.1	$ 213.3
Asset retirement obligation expenditures	1.3	0.3	8.4	11.1
Changes in non-cash operating working capital	46.1	(20.9)	129.9	(41.2)
Adjusted funds flow	$ 184.3	$ 70.0	$ 312.4	$ 183.2

"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 as outlined in the Capital Investment section of this MD&A.

Calculation of Free Cash Flow	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2021**	**2020**	**2021**	**2020**
Adjusted funds flow	$ 184.3	$ 70.0	$ 312.4	$ 183.2
Capital spending	(129.9)	(40.1)	(195.4)	(203.7)
Free cash flow	$ 54.4	$ 29.9	$ 117.0	$ (20.5)

"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, goodwill impairment, unrealized foreign exchange gain/loss, the associated tax effect of these items, and the valuation allowance on our deferred income tax assets.

Calculation of Adjusted Net Income	Three months ended June 30,		Six months ended June 30,	
($ millions)	2021	2020	2021	2020
Net income/(loss)	$ (59.7)	$ (609.3)	$ (45.0)	$ (606.4)
Unrealized derivative instrument (gain)/loss	160.1	63.9	210.0	(32.5)
Asset impairment	—	426.8	4.3	426.8
Unrealized foreign exchange (gain)/loss	5.5	1.0	5.9	(1.4)
Tax effect on above items	(38.0)	(126.4)	(51.0)	(103.0)
Goodwill impairment	—	202.8	—	202.8
Valuation allowance on deferred taxes	—	—	—	93.6
Adjusted net income/(loss)	$ 67.9	$ (41.2)	$ 124.2	$ (20.1)

"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 term loan 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 trailing twelve months of adjusted funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depreciation, amortization, accretion, 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 and office expenditures, divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	Three months ended June 30,		Six months ended June 30,	
($ millions)	2021	2020	2021	2020
Dividends	$ 11.0	$ 6.7	$ 18.4	$ 13.3
Capital and office expenditures	130.4	41.0	196.3	206.5
Sub-total	$ 141.4	$ 47.7	$ 214.7	$ 219.8
Adjusted funds flow	$ 184.3	$ 70.0	$ 312.4	$ 183.2
Adjusted payout ratio (%)	77%	68%	69%	120%

"Adjusted EBITDA" is used by Enerplus and its lenders to determine compliance with financial covenants under the Bank Credit Facility, term loan, and outstanding senior notes. Adjusted EBITDA is calculated on the trailing four quarters.

Reconciliation of Net Income to Adjusted EBITDA(1)	
($ millions)	June 30, 2021
Net income/(loss)	$ (361.9)
Add:	
Interest expense	28.8
Current and deferred tax expense/(recovery)	(252.7)
DD&A and asset impairment	830.8
Other non-cash charges(2)	275.3
Sub-total	$ 520.3
Adjustment for material acquisitions and divestments(3)	101.0
Adjusted EBITDA	$ 621.3

(1) Balances above at June 30, 2021 include the six months ended June 30, 2021 and the third and fourth quarter of 2020.
(2) Includes the change in fair value of commodity derivatives and equity swaps, non-cash SBC expense, non-cash G&A expense, non-cash amortization of debt issuance costs and unrealized foreign exchange gains/losses.
(3) EBITDA is adjusted for material acquisitions or divestments during the period with net proceeds greater than US$37.5 million as if that acquisition or disposition has been made at the beginning of the period.

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 the Bank Credit Facility, term loan 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, 2021, 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, 2021 and ended June 30, 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected benefits of the Dunn County Acquisition and the Bruin Acquisition; expected impact of the Dunn County Acquisition and Bruin Acquisition on Enerplus' operations and financial results; anticipated impact of the Dunn County Acquisition and the Bruin Acquisition on Enerplus' future costs and expenses; the renewal of Enerplus' NCIB and terms thereof; expected capital spending levels 2021 and impact thereof on our production levels and land holdings; expected production volumes and updated 2021 production guidance; expected operating strategy in 2021, including the effect of Enerplus' production curtailment on its properties, operations and financial position; the effect of Enerplus' participation in the DAPL expansion on increased crude oil transportation; 2021 average production volumes, timing thereof and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the expected effectiveness of such hedges in protecting our adjusted funds flow; the results from our drilling program and the timing of related production and ultimate well recoveries; oil and natural gas prices and differentials, our commodity risk management program in 2021 and expected hedging gains; expectations regarding our realized oil and natural gas prices; expected operating, transportation, cash G&A costs and share-based compensation and financing expenses; 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 payment of increased dividends; expectations regarding our ability to comply with debt covenants under our Bank Credit Facility, term loan and outstanding senior notes; expectations regarding payment of increased dividends; Enerplus' costs reduction initiatives and the expected cost savings therefrom in 2021; the amount of future cash dividends that we may pay to our shareholders; and our ESG initiatives, including GHG emissions and water reduction targets for 2021.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: the benefits of the Dunn County Acquisition and the Bruin Acquisition; that Enerplus will realize the expected impact of the Dunn County Acquisition and the Bruin Acquisition on Enerplus' operations and financial results and on Enerplus' future costs and expenses will be as expected and as discussed in this MD&A; that we will conduct our operations and achieve results of operations as anticipated; the continued ability to operate DAPL; 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, including expectations regarding the duration and overall impact of COVID-19; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the 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; the extent of our liabilities; the rates used to calculate the amount of our future abandonment and reclamation costs and asset retirement obligations; and the availability of technology and process to achieve environmental targets. In addition, our expected 2021 capital expenditures, operating strategy and 2021 guidance described in this MD&A is based on the rest of the year prices and exchange rate of: a WTI price of US$69.00/bbl, a NYMEX price of US$3.92/Mcf and a USD/CDN exchange rate of 1.26. 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: failure by Enerplus to realize anticipated benefits of the Dunn County Acquisition or the Bruin Acquisition; continued instability, or further deterioration, in global economic and market environment, including from COVID-19; continued low commodity price environment or further decline and/or volatility in commodity prices; changes in realized prices of Enerplus' products from those currently anticipated; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; legal proceedings in connection with DAPL; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; 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; changes in law or government programs or policies in Canada or the United States; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in this MD&A, our Annual Information Form, our Annual MD&A and Form 40-F as at December 31, 2020).

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

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	June 30, 2021	December 31, 2020
Assets			
Current Assets			
Cash and cash equivalents		$ 75,278	$ 114,455
Accounts receivable	5	252,316	106,376
Derivative financial assets	17	—	3,550
Other current assets		7,505	7,137
		335,099	231,518
Property, plant and equipment:			
Crude oil and natural gas properties (full cost method)	6	1,680,329	575,559
Other capital assets, net	6	18,912	19,524
Property, plant and equipment		1,699,241	595,083
Right-of-use assets	11	36,951	32,853
Deferred income tax asset	15	600,257	607,001
Total Assets		$ 2,671,548	$ 1,466,455
Liabilities			
Current liabilities			
Accounts payable	8	$ 379,255	$ 251,822
Dividends payable		—	2,225
Current portion of long-term debt	9	98,688	103,836
Derivative financial liabilities	17	225,696	19,261
Current portion of lease liabilities	11	12,940	13,391
		716,579	390,535
Derivative financial liabilities	17	64,536	—
Long-term debt	9	1,109,431	386,586
Asset retirement obligation	10	160,201	130,208
Lease liabilities	11	27,668	23,446
		1,361,836	540,240
Total Liabilities		2,078,415	930,775
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: June 30, 2021 – 257 million shares			
December 31, 2020 – 223 million shares	16	3,236,117	3,096,969
Paid-in capital		36,269	50,604
Accumulated deficit		(2,995,389)	(2,932,017)
Accumulated other comprehensive income/(loss)		316,136	320,124
		593,133	535,680
Total Liabilities & Shareholders' Equity		$ 2,671,548	$ 1,466,455

Subsequent Events 16,19

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, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Revenues					
Crude oil and natural gas sales, net of royalties	12	$ 408,622	$ 122,069	$ 697,423	$ 350,196
Commodity derivative instruments gain/(loss)	17	(197,967)	(10,895)	(267,810)	120,446
		210,655	111,174	429,613	470,642
Expenses					
Operating		88,459	54,353	152,981	133,373
Transportation		36,188	34,006	69,011	69,335
Production taxes		30,502	7,687	47,954	23,131
General and administrative	13	12,474	13,494	28,746	32,679
Depletion, depreciation and accretion		93,908	79,885	140,368	175,077
Asset impairment	7	—	426,810	4,300	426,810
Goodwill impairment	7	—	202,767	—	202,767
Interest		9,527	7,051	16,350	15,962
Foreign exchange (gain)/loss	14	6,864	1,493	6,986	(4,144)
Transaction costs and other expense/(income)	4,10	(718)	6,301	3,806	6,072
		277,204	833,847	470,502	1,081,062
Income/(Loss) before taxes		(66,549)	(722,673)	(40,889)	(610,420)
Current income tax expense/(recovery)	15	4,175	(14,422)	4,175	(14,395)
Deferred income tax expense/(recovery)	15	(11,060)	(98,928)	(97)	10,422
Net Income/(Loss)		$ (59,664)	$ (609,323)	$ (44,967)	$ (606,447)
Other Comprehensive Income/(Loss)					
Unrealized gain/(loss) on foreign currency translation		(14,345)	(57,284)	(27,212)	74,490
Foreign exchange gain/(loss) on net investment hedge with U.S. denominated debt, net of tax	17	14,702	19,466	23,224	(30,596)
Total Comprehensive Income/(Loss)		$ (59,307)	$ (647,141)	$ (48,955)	$ (562,553)
Net income/(Loss) per share					
Basic	16	$ (0.23)	$ (2.74)	$ (0.18)	$ (2.73)
Diluted	16	$ (0.23)	$ (2.74)	$ (0.18)	$ (2.73)

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, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Share Capital				
Balance, beginning of period	$ 3,236,117	$ 3,097,187	$ 3,096,969	$ 3,088,094
Issue of shares (net of issue costs, less tax)	—	—	127,248	—
Purchase of common shares under Normal Course Issuer Bid	—	—	—	(4,731)
Share-based compensation – treasury settled	—	—	11,900	13,824
Cancellation of predecessor shares	—	(218)	—	(218)
Balance, end of period	$ 3,236,117	$ 3,096,969	$ 3,236,117	$ 3,096,969
Paid-in Capital				
Balance, beginning of period	$ 36,305	$ 44,430	$ 50,604	$ 59,490
Share-based compensation – cash settled (tax withholding)	—	—	(4,491)	(7,232)
Share-based compensation – treasury settled	—	—	(11,900)	(13,824)
Share-based compensation – non-cash	(36)	4,328	2,056	10,324
Balance, end of period	$ 36,269	$ 48,758	$ 36,269	$ 48,758
Accumulated Deficit				
Balance, beginning of period	$ (2,924,685)	$ (1,985,964)	$ (2,932,017)	$ (1,984,365)
Purchase of common shares under Normal Course Issuer Bid	—	—	—	2,195
Cancellation of predecessor shares	—	218	—	218
Net income/(loss)	(59,664)	(609,323)	(44,967)	(606,447)
Dividends declared(1)	(11,040)	(6,675)	(18,405)	(13,345)
Balance, end of period	$ (2,995,389)	$ (2,601,744)	$ (2,995,389)	$ (2,601,744)
Accumulated Other Comprehensive Income/(Loss)				
Balance, beginning of period	$ 315,779	$ 390,051	$ 320,124	$ 308,339
Unrealized gain/(loss) on foreign currency translation	(14,345)	(57,284)	(27,212)	74,490
Foreign exchange gain/(loss) on net investment hedge with U.S. denominated debt, net of tax	14,702	19,466	23,224	(30,596)
Balance, end of period	$ 316,136	$ 352,233	$ 316,136	$ 352,233
Total Shareholders' Equity	$ 593,133	$ 896,216	$ 593,133	$ 896,217

(1) For the three and six months ended June 30, 2021, dividends declared were $0.043 per share and $0.073 per share, respectively (2020 – $0.03 per share and $0.03 per share, respectively).

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

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Note	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Operating Activities					
Net income/(loss)		$ (59,664)	$ (609,323)	$ (44,967)	$ (606,447)
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		93,908	79,885	140,368	175,077
Asset impairment	7	—	426,810	4,300	426,810
Goodwill impairment	7	—	202,767	—	202,767
Changes in fair value of derivative instruments	17	160,130	63,929	209,972	(32,499)
Deferred income tax expense/(recovery)	15	(11,060)	(98,928)	(97)	10,422
Foreign exchange (gain)/loss on debt and working capital	14	5,539	1,038	5,858	(1,377)
Share-based compensation and general and administrative	13,16	(23)	3,428	990	11,183
Other expense/(income)	10	(2,353)	—	(2,353)	—
Amortization of debt issuance costs	9	312	—	385	—
Translation of U.S. dollar cash held in Canada	14	(2,469)	391	(2,021)	(2,712)
Asset retirement obligation settlements	10	(1,359)	(333)	(8,439)	(11,127)
Changes in non-cash operating working capital	18	(46,059)	20,896	(129,855)	41,202
Cash flow from/(used in) operating activities		136,902	90,560	174,141	213,299
Financing Activities					
Bank term loan	9	—	—	501,286	—
Bank credit facility	9	333,616	1,364	333,616	1,364
Repayment of senior notes	9	(99,348)	(114,010)	(99,348)	(114,010)
Proceeds from the issuance of shares	16	—	—	125,746	—
Purchase of common shares under Normal Course Issuer Bid	16	—	—	—	(2,536)
Share-based compensation – cash settled (tax withholding)	16	—	—	(4,491)	(7,232)
Dividends	16,18	(13,608)	(6,676)	(20,627)	(13,337)
Cash flow from/(used in) financing activities		220,660	(119,322)	836,182	(135,751)
Investing Activities					
Capital and office expenditures	18	(92,422)	(104,111)	(144,184)	(233,453)
Bruin acquisition	4	(2,537)	—	(531,134)	—
Dunn County acquisition	4	(374,613)	—	(374,613)	—
Property and land acquisitions		(1,619)	(3,416)	(5,026)	(5,672)
Property divestments		(17)	(63)	4,978	5,515
Cash flow from/(used in) investing activities		(471,208)	(107,590)	(1,049,979)	(233,610)
Effect of exchange rate changes on cash & cash equivalents		(92)	453	479	10,590
Change in cash and cash equivalents		(113,738)	(135,899)	(39,177)	(145,472)
Cash and cash equivalents, beginning of period		189,016	142,076	114,455	151,649
Cash and cash equivalents, end of period		$ 75,278	$ 6,177	$ 75,278	$ 6,177

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

Notes to Condensed Consolidated Financial Statements

(unaudited)

1) REPORTING ENTITY

These interim Condensed Consolidated Financial Statements ("interim Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation (the "Company" or "Enerplus") including its Canadian and United States ("U.S.") subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' 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, 2021 and the 2020 comparative periods. Certain prior period amounts have been reclassified to conform with current period presentation. Certain information and notes normally included with the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with Enerplus' annual audited Consolidated Financial Statements as of December 31, 2020.

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

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Actual results could differ from these estimates, and changes in estimates are recorded when known. Significant estimates made by management include: crude oil and natural gas reserves and related present value of future cash flows, depreciation, depletion and accretion ("DD&A"), fair value of acquired property, plant and equipment, impairment of property, plant and equipment, asset retirement obligation, income taxes, ability to realize deferred income tax assets and the fair value of derivative instruments. The estimation of crude oil and natural gas reserves and the related present value of future cash flows involves the use of independent reservoir engineering specialists and numerous inputs and assumptions including forecasted production volumes, forecasted operating, royalty and capital cost assumptions and assumptions around commodity pricing. When estimating the present value of future cash flows, the discount rate is not directly adjusted for the potential impacts, if any, due to climate change factors. The ultimate period in which global energy markets can fully transition from carbon-based sources to alternative energy is highly uncertain. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions.

3) ACCOUNTING POLICY CHANGES

Recently adopted accounting standards

Government Assistance

In 2020, the Alberta, Saskatchewan, and British Columbia provincial governments created programs and provided funding to support the clean-up of inactive or abandoned crude oil and natural gas wells. Enerplus has applied for and benefited from these programs in 2021. The programs provide funding directly to oil field service contractors engaged by companies to perform abandonment, remediation, and reclamation work. As work is completed, the contractors submit invoices to the provincial government for reimbursement for the pre-approved funding amounts. Enerplus recognizes the assistance as the abandonment, remediation, and reclamation work is completed by the contractor. The benefit of the funding received by the contractor is reflected as a reduction of asset retirement obligation and recorded as other income.

4) ACQUISITIONS

a) Bruin E&P HoldCo, LLC Acquisition

On January 25, 2021, Enerplus Resources (USA) Corporation, an indirect wholly-owned subsidiary of Enerplus entered into a purchase agreement to acquire all of the equity interests of Bruin E&P HoldCo, LLC ("Bruin") for total cash consideration of US$465 million, subject to certain purchase price adjustments. Bruin was a private company that held oil and gas interests in certain properties located in the Williston Basin, North Dakota. The effective date of the acquisition was January 1, 2021 and the acquisition was completed on March 10, 2021.

The acquisition was funded through a new three-year US$400 million term loan provided by a syndicate of financial institutions as well as a portion of the proceeds raised through a bought deal offering of common shares of the Company, which was completed on February 3, 2021. A total of 33,062,500 common shares were issued at a price of $4.00 per common share for gross proceeds of approximately $132.3 million (net proceeds of $127.2 million).

The acquisition contributed $124.0 million to crude oil and natural gas revenues, net of royalties and $54.2 million to consolidated net earnings from the acquisition date to June 30, 2021. Transaction costs of $1.7 million and $6.2 million were incurred for the three and six months ended June 30, 2021, respectively.

If the transaction had occurred on January 1, 2021, the combined entity's unaudited pro-forma crude oil and natural gas revenues, net of royalties would be $408.6 million and $768.7 million, respectively, for the three and six months ended June 30, 2021 (2020 – $106.5 million and $450.6 million, respectively). For the three and six months ended June 30, 2021 the combined entity would have net losses of $59.7 million and $91.8 million, respectively (2020 – net losses of $913.7 million and $1,333.4 million, respectively).

The unaudited pro-forma information may not be indicative of the results that actually would have occurred if the events reflected therein had been in effect on the dates indicated or of the results that may be obtained in the future. No adjustment has been made to reflect operating synergies that may be realized as a result of the transaction.

Purchase Price Consideration

The transaction was accounted for as an acquisition of a business. The purchase price is measured as the fair value of the assets transferred, equity instruments issued, and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The purchase price equation was determined following the closing date, during which time the value of the net assets and liabilities acquired was revised as indicated in the agreement and is reflected in the following:

Purchase Price Equation

($ thousands)	At March 10, 2021
Consideration	
Purchase Price (US$465 million)	$ 587,667
Purchase price adjustments	(56,533)
Total consideration	$ 531,134
Fair value of identifiable assets and liabilities of Bruin	
Other current assets	2,108
Property, plant and equipment	685,219
Right of use assets	2,391
Accounts payable	(31,920)
Asset retirement obligation	(27,759)
Derivative financial liabilities	(96,514)
Lease liabilities	(2,391)
Total identifiable net assets	$ 531,134

b) Dunn County Acquisition

On April 8, 2021, the Company announced it had entered into a purchase agreement to acquire assets in Dunn County, North Dakota from Hess Bakken Investments II, LLC for total cash consideration of approximately US$312 million, subject to customary purchase price adjustments. The acquisition was funded using the Company's existing cash balance with the remaining portion funded through borrowing on its bank credit facility. The effective date of the acquisition was March 1, 2021 and the acquisition closed on April 30, 2021.

The acquisition was recorded as an asset acquisition as of the close date of April 30, 2021 with the results of operations reflected in these interim Consolidated Financial Statements thereafter. After purchase price adjustments, the purchase consideration including capitalized transaction costs was $376.9 million (US$306.8 million).

5) ACCOUNTS RECEIVABLE

($ thousands)		June 30, 2021		December 31, 2020
Accrued revenue	$	229,166	$	93,147
Accounts receivable – trade		28,150		16,808
Allowance for doubtful accounts		(5,000)		(3,579)
Total accounts receivable, net of allowance for doubtful accounts	$	252,316	$	106,376

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

As of June 30, 2021 ($ thousands)		Cost		Accumulated Depletion, Depreciation, and Impairment		Net Book Value
Crude oil and natural gas properties[1]	$	16,296,417	$	(14,616,088)	$	1,680,329
Other capital assets		128,951		(110,039)		18,912
Total PP&E	$	16,425,368	$	(14,726,127)	$	1,699,241

As of December 31, 2020 ($ thousands)		Cost		Accumulated Depletion, Depreciation, and Impairment		Net Book Value
Crude oil and natural gas properties[1]	$	15,227,076	$	(14,651,517)	$	575,559
Other capital assets		127,527		(108,003)		19,524
Total PP&E	$	15,354,603	$	(14,759,520)	$	595,083

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

7) IMPAIRMENT

a) Impairment of PP&E

	Three months ended June 30,				Six months ended June 30,			
($ thousands)		2021		2020		2021		2020
Crude oil and natural gas properties:								
Canada cost centre	$	—	$	77,500	$	4,300	$	77,500
U.S. cost centre		—		349,310		—		349,310
Asset impairment	$	—	$	426,810	$	4,300	$	426,810

For the three and six months ended June 30, 2021, Enerplus recorded asset impairments of nil and $4.3 million, respectively (2020 – $426.8 million, respectively). During the first six months of 2021, all asset impairments recorded related to Enerplus' Canadian cost centre, whereas the asset impairments recorded in the first six months of 2020 related to both Canadian and U.S. cost centres. The primary factors that affect future ceiling values include future first-day-of-the-month commodity prices, reserves revisions, capital expenditure levels and timing, acquisition and divestment activity, and production levels.

The following table outlines the twelve month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from June 30, 2020 through June 30, 2021:

Period	WTI Crude Oil US$/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	Exchange Rate US$/CDN$
Q2 2021	$ 49.72	$ 58.31	$ 2.47	1.28
Q1 2021	39.95	46.10	2.18	1.33
Q4 2020	39.54	45.56	2.00	1.34
Q3 2020	43.63	50.03	1.97	1.34
Q2 2020	47.37	54.94	2.08	1.34

b) Ceiling Test Exemption

Enerplus is required to calculate a full cost ceiling test at each reporting period, using constant prices as defined by the SEC under U.S. GAAP. These prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. At March 31, 2021, the ceiling test resulted in the net carrying cost of Enerplus' crude oil and natural gas properties in its U.S. cost centre to exceed the ceiling test limitation by approximately US$265 million. This was primarily due to the difference in the ceiling value, using SEC constant prices for the Bruin assets acquired compared to the carrying value, which more closely represented fair market value based on forward prices. Enerplus requested and received a temporary exemption from the SEC to exclude the properties acquired from Bruin in the full cost ceiling test for the duration of 2021. At June 30, 2021, the ceiling test limitation exceeded the net carrying cost of the crude oil and natural gas properties, including the Bruin assets, in Enerplus' U.S. cost centre.

c) Impairment of Goodwill

At June 30, 2021, there was no goodwill remaining on the Company's Condensed Consolidated Balance Sheets (December 31, 2020 – nil). During the three and six months ended June 30, 2020, Enerplus recorded goodwill impairment of $202.8 million related to its U.S. reporting unit as a result of lower commodity prices, which resulted in a reduction in the fair value of the U.S. reporting unit.

8) ACCOUNTS PAYABLE

($ thousands)	June 30, 2021	December 31, 2020
Accrued payables	$ 140,890	$ 107,254
Accounts payable – trade	238,365	144,568
Total accounts payable	$ 379,255	$ 251,822

9) DEBT

($ thousands)	June 30, 2021	December 31, 2020
Current:		
Senior notes	$ 98,688	$ 103,836
Long-term:		
Bank credit facility	338,729	—
Term loan	492,738	—
Senior notes	277,964	386,586
Total debt	$ 1,208,119	$ 490,422

Upon closing the Bruin acquisition on March 10, 2021, Enerplus entered into a three-year senior unsecured US$400 million term loan. The drawn fees align with those of Enerplus' bank credit facility, which range between 125 and 315 basis points over banker's acceptance or LIBOR rates. The term loan includes financial and other covenants consistent with Enerplus' bank credit facility and ranks equally with the bank credit facility and outstanding senior notes. Debt issuance costs of $3.5 million have been netted against the term loan and are being amortized over the three-year term.

During the three months ended June 30, 2021, Enerplus increased and extended its senior, unsecured, covenant-based bank credit facility to US$900 million from US$600 million with a maturity of October 31, 2025. Debt issuance costs of $2.2 million have been netted against the bank credit facility and are being amortized over the four and a half year term. As part of the extension, the Company transitioned the facility to a sustainability-linked credit facility incorporating environmental, social and governance ("ESG")-linked incentive pricing terms which reduce or increase the borrowing costs by up to 5 basis points as Enerplus' sustainability performance targets ("SPT") are exceeded or missed. The SPTs are based on the following ESG goals of the Company:

- **GHG Emissions**: continuous progress toward Enerplus' stated goal of a 50% reduction in corporate Scope 1 and 2 greenhouse gas emissions intensity by 2030, using 2019 as a baseline and measurement based on Enerplus' annual internal targets;
- **Water Management**: achieve a 50% reduction in freshwater usage in corporate well completions by 2025 or earlier compared to 2019, with progress to be measured on an annual basis over the life of the credit facility; and
- **Health & Safety**: achieve and maintain a 25% reduction in the Company's Lost Time Injury Frequency, based on a trailing 3-year average, relative to a 2019 baseline.

For the three and six months ended June 30, 2021, total amortization of debt issuance costs amounted to $0.3 million and $0.4 million, respectively.

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	$ 130,179
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	24,796
May 15, 2012	May 15 and Nov 15	3 equal annual installments beginning May 15, 2022	4.40%	US$355,000	US$178,800	221,677
					Total carrying value	$ 376,652

During the three months ended June 30, 2021, Enerplus made its final US$22 million principal repayment on its 2009 senior notes and its second US$59.6 million principal repayment on its 2012 senior notes.

10) ASSET RETIREMENT OBLIGATION ("ARO")

($ thousands)	June 30, 2021	December 31, 2020
Balance, beginning of year	$ 130,208	$ 138,049
Change in estimates	4,067	1,331
Property acquisitions and development activity	275	2,246
Bruin acquisition (Note 4a)	27,759	—
Dunn County acquisition (Note 4b)	7,291	—
Divestments	(2,010)	(1,030)
Settlements	(8,439)	(17,709)
Government assistance	(2,353)	—
Accretion expense	3,403	7,321
Balance, end of period	$ 160,201	$ 130,208

Enerplus has estimated the present value of its ARO to be $160.2 million at June 30, 2021 based on a total undiscounted uninflated liability of $430.3 million (December 31, 2020 – $130.2 million and $348.4 million, respectively). The asset retirement obligation was calculated using a weighted average credit-adjusted risk-free rate of 5.05% and inflation rate of 0.9% (December 31, 2020 – 5.35% and 0.9%).

In 2021, Enerplus benefited from provincial government assistance to support the clean-up of inactive or abandoned crude oil and natural gas wells. These programs provide funding directly to oil field service contractors engaged by Enerplus to perform abandonment, remediation, and reclamation work. The funding received by the contractor is reflected as a reduction to ARO. For the six months ended June 30, 2021, Enerplus benefited from $2.4 million in government assistance, which was recorded as other income.

11) LEASES

The Company incurs various 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 Sheets. Such items are charged to operating expenses or general and administrative expenses, as appropriate, in the Condensed Consolidated Statements of Income/(Loss), unless the costs are included in the carrying amount of another asset in accordance with U.S. GAAP.

($ thousands)	June 30, 2021	December 31, 2020
Assets		
Operating right-of-use assets	$ 36,951	$ 32,853
Liabilities		
Current operating lease liabilities	$ 12,940	$ 13,391
Non-current operating lease liabilities	27,668	23,446
Total lease liabilities	$ 40,608	$ 36,837
Weighted average remaining lease term (years)		
Operating leases	3.6	3.9
Weighted average discount rate		
Operating leases	3.4%	4.2%

The components of lease expenditures for the three and six months ended June 30, 2021 are as follows:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2021	2020	2021	2020
Operating lease cost	$ 3,413	$ 4,182	$ 7,019	$ 9,315
Variable lease cost	333	190	363	507
Short-term lease cost	922	1,893	1,625	7,177
Sublease income	(346)	(251)	(588)	(544)
Total	$ 4,322	$ 6,014	$ 8,419	$ 16,455

Maturities of lease liabilities, all of which are classified as operating leases at June 30, 2021 are as follows:

($ thousands)	Operating Leases
2021	$ 7,121
2022	13,508
2023	11,940
2024	6,975
2025	1,171
After 2025	2,627
Total lease payments	$ 43,342
Less imputed interest	(2,734)
Total discounted lease payments	$ 40,608
Current portion of lease liabilities	$ 12,940
Non-current portion of lease liabilities	$ 27,668

Supplemental information related to leases is as follows:

($ thousands)	Three months ended June 30, 2021	2020	Six months ended June 30, 2021	2020
Cash amounts paid to settle lease liabilities:				
Operating cash flow used for operating leases	$ 3,517	$ 3,913	$ 7,249	$ 8,841
Right-of-use assets obtained/(terminated) in exchange for lease liabilities:				
Operating leases	$ 8,103	$ (3,473)	$ 10,822	$ (2,950)

12) CRUDE OIL AND NATURAL GAS SALES, NET OF ROYALTIES

($ thousands)	Three months ended June 30, 2021	2020	Six months ended June 30, 2021	2020
Crude oil and natural gas sales	$ 510,194	$ 155,259	$ 869,485	$ 440,857
Royalties(1)	(101,572)	(33,190)	(172,062)	(90,661)
Crude oil and natural gas sales, net of royalties	$ 408,622	$ 122,069	$ 697,423	$ 350,196

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

Crude oil and natural gas revenue by country and by product for the three and six months ended June 30, 2021 and 2020 are as follows:

Three months ended June 30, 2021 ($ thousands)	**Total revenue, net of royalties(1)**	**Crude oil(2)**	**Natural gas(2)**	**Natural gas liquids(2)**	**Other(3)**
Canada	$ 36,515	$ 32,935	$ 2,248	$ 1,169	$ 163
United States	372,107	313,327	43,725	15,047	8
Total	$ 408,622	$ 346,262	$ 45,973	$ 16,216	$ 171

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

Six months ended June 30, 2021 ($ thousands)	**Total revenue, net of royalties(1)**	**Crude oil(2)**	**Natural gas(2)**	**Natural gas liquids(2)**	**Other(3)**
Canada	$ 71,061	$ 61,988	$ 6,127	$ 2,483	$ 463
United States	626,362	490,816	104,657	30,873	16
Total	$ 697,423	$ 552,804	$ 110,784	$ 33,356	$ 479

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

(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.

13) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	Three months ended June 30, 2021	2020	Six months ended June 30, 2021	2020
General and administrative expense(1)	$ 10,766	$ 9,231	$ 23,755	$ 21,566
Share-based compensation expense	1,708	4,263	4,991	11,113
General and administrative expense	$ 12,474	$ 13,494	$ 28,746	$ 32,679

(1) Includes a non-cash lease credit of $112 and $225 for the three and six months ended June 30, 2021 (2020 – credit of $121 and $53).

14) FOREIGN EXCHANGE

($ thousands)	Three months ended June 30, 2021	2020	Six months ended June 30, 2021	2020
Realized:				
Foreign exchange (gain)/loss	$ 3,794	$ 64	$ 3,149	$ (55)
Translation of U.S. dollar cash held in Canada (gain)/loss	(2,469)	391	(2,021)	(2,712)
Unrealized:				
Translation of debt and working capital (gain)/loss	5,539	1,038	5,858	(1,377)
Foreign exchange (gain)/loss	$ 6,864	$ 1,493	$ 6,986	$ (4,144)

15) INCOME TAXES

($ thousands)	Three months ended June 30, 2021	2020	Six months ended June 30, 2021	2020
Current tax				
Canada	$ —	$ —	$ —	$ —
United States	4,175	(14,422)	4,175	(14,395)
Current tax expense/(recovery)	4,175	(14,422)	4,175	(14,395)
Deferred tax				
Canada	$ (42,232)	$ (25,629)	$ (55,254)	$ 98,852
United States	31,172	(73,299)	55,157	(88,430)
Deferred tax expense/(recovery)	(11,060)	(98,928)	(97)	10,422
Income tax expense/(recovery)	$ (6,885)	$ (113,350)	$ 4,078	$ (3,973)

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

The Company's overall net deferred income tax asset was $600.3 million as at June 30, 2021 (December 31, 2020 – $607.0 million).

16) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized unlimited number of common shares issued: (thousands)	Six months ended June 30, 2021 Shares	Amount	Year ended December 31, 2020 Shares	Amount
Balance, beginning of year	222,548	$ 3,096,969	221,744	$ 3,088,094
Issued/(Purchased) for cash:				
Issue of shares (net of issue costs, less tax)	33,062	127,248	—	—
Purchase of common shares under Normal Course Issuer Bid	—	—	(340)	(4,731)
Non-cash:				
Share-based compensation – treasury settled(1)	1,140	11,900	1,160	13,824
Cancellation of predecessor shares	—	—	(16)	(218)
Balance, end of period	256,750	$ 3,236,117	222,548	$ 3,096,969

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

Dividends declared to shareholders for the three and six months ended June 30, 2021 were $11.0 million and $18.4 million, respectively (2020 – $6.7 million and $13.3 million, respectively). During the second quarter of 2021, the Company's Board of Directors approved a 10% increase to the dividend to $0.033 per share paid quarterly beginning in June 2021, from $0.01 per share paid monthly previously. Subsequent to the quarter, the Board of Directors approved a 15% increase to the dividend to $0.038 per share, to be paid quarterly, beginning September 2021.

During the six months ended June 30, 2021, Enerplus issued 33,062,500 common shares at a price of $4.00 per common share for gross proceeds of $132.3 million ($127.2 million, net of $6.6 million in issue costs, less $1.5 million in tax) pursuant to a bought deal prospectus offering under its base shelf prospectus.

On June 23, 2021, the Company filed a short form base shelf prospectus (the "Shelf Prospectus") with securities regulatory authorities in each of the provinces and territories of Canada and a Registration Statement with the U.S. Securities Exchange Commission. The Shelf Prospectus allows Enerplus to offer and issue up to an aggregate amount of $2.0 billion common shares, preferred shares, warrants, subscription receipts and units by way of one or more prospectus supplements during the 25-month period that the Shelf Prospectus remains valid.

Subsequent to June 30, 2021, Enerplus received approval from the Board of Directors to commence a Normal Course Issuer Bid ("NCIB") to purchase up to 10% of the public float (within the meaning under Toronto Stock Exchange ("TSX") rules) during a 12-month period. The NCIB remains subject to approval by the TSX.

b) Share-based Compensation

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

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2021	2020	2021	2020
Cash:				
Long-term incentive plans (recovery)/expense	$ 2,302	$ 1,186	$ 5,050	$ (1,561)
Non-Cash:				
Long-term incentive plans expense	89	3,550	1,216	11,239
Equity swap (gain)/loss	(683)	(473)	(1,275)	1,435
Share-based compensation expense	$ 1,708	$ 4,263	$ 4,991	$ 11,113

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, 2021:

	Cash-settled LTI plans	Equity-settled LTI plans		Total
(thousands of units)	Director Plans	PSU(1)	RSU	
Balance, beginning of year	555	2,552	1,825	4,932
Granted	263	2,126	2,163	4,552
Vested	(13)	(728)	(890)	(1,631)
Forfeited	—	—	(58)	(58)
Balance, end of period	805	3,950	3,040	7,795

(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, 2021, the Company recorded a cash share-based compensation expense of $2.3 million and $5.1 million, respectively (June 30, 2020 – expense of $1.2 million and recovery of $1.6 million, respectively).

As of June 30, 2021, a liability of $7.2 million (December 31, 2020 – $2.2 million) with respect to the Director DSU and DRSU plans has been recorded to Accounts Payable on the Condensed Consolidated Balance Sheets.

Equity-settled LTI Plans

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

At June 30, 2021 ($ thousands, except for years)	PSU(1)	RSU	Total
Cumulative recognized share-based compensation expense	$ 3,971	$ 9,285	$ 13,256
Unrecognized share-based compensation expense	9,458	9,412	18,870
Fair value	$ 13,429	$ 18,697	$ 32,126
Weighted-average remaining contractual term (years)	1.7	1.3	

(1) Includes estimated performance multipliers.

The Company directly withholds shares on PSU and RSU settlements for tax-withholding purposes. For the three and six months ended June 30, 2021, nil and $4.5 million (2020 – nil and $7.2 million) in cash withholding taxes were paid.

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

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

	Three months ended June 30,		Six months ended June 30,	
(thousands, except per share amounts)	2021	2020	2021	2020
Net income/(loss)	$ (59,664)	$ (609,323)	$ (44,967)	$ (606,447)
Weighted average shares outstanding – Basic	256,750	222,557	250,443	222,457
Weighted average shares outstanding – Diluted(1)	256,750	222,557	250,443	222,457
Net income/(loss) per share				
Basic	$ (0.23)	$ (2.74)	$ (0.18)	$ (2.73)
Diluted	$ (0.23)	$ (2.74)	$ (0.18)	$ (2.73)

(1) For the three and six months ended June 30, 2021, the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the net loss per share.

17) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At June 30, 2021, the carrying value of cash and cash equivalents, accounts receivable, and accounts payable approximated their fair value due to the short-term nature of these instruments.

At June 30, 2021, the senior notes had a carrying value of $376.7 million and a fair value of $379.7 million (December 31, 2020 – $490.4 million and $494.1 million, respectively). The fair values of the bank credit facility and term loan approximate their carrying values as they bear interest at floating rates and the credit spread approximates current market rates.

The fair value of derivative contracts, senior notes, term loan, and credit facility 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 income statement change in fair value for the three and six months ended June 30, 2021 and 2020:

	Three months ended June 30,		Six months ended June 30,		Income Statement
Gain/(Loss) ($ thousands)	2021	2020	2021	2020	Presentation
Equity Swaps	$ 683	$ 473	$ 1,275	$ (1,435)	G&A expense
Commodity Derivative Instruments:					
Oil	(146,878)	(64,402)	(198,547)	33,934	Commodity derivative
Gas	(13,935)	—	(12,700)	—	instruments
Total	$ (160,130)	$ (63,929)	$ (209,972)	$ 32,499	

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

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2021	2020	2021	2020
Unrealized change in fair value gain/(loss)	$ (160,813)	$ (64,402)	$ (211,247)	$ 33,934
Net realized cash gain/(loss)	(37,154)	53,507	(56,563)	86,512
Commodity derivative instruments gain/(loss)	$ (197,967)	$ (10,895)	$ (267,810)	$ 120,446

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

	June 30, 2021		December 31, 2020		
	Liabilities		Assets	Liabilities	
($ thousands)	Current	Long-term	Current	Current	Long-term
Equity Swaps	$ 2,338	$ —	$ —	$ 3,613	$ —
Commodity Derivative Instruments:					
Oil	214,209	64,536	—	15,648	—
Gas	9,149	—	3,550	—	—
Total	$ 225,696	$ 64,536	$ 3,550	$ 19,261	$ —

On March 10, 2021, the outstanding crude oil contracts acquired with the Bruin acquisition were recorded at fair value, resulting in a liability of $96.5 million on the Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired contracts are recognized in the Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the closing date of the Bruin acquisition. At June 30, 2021, the fair value of the remaining Bruin contracts was a liability of $99.9 million, including $64.5 million of the original $96.5 million liability acquired. For the three and six months ended June 30, 2021 the Company recorded a realized loss of $2.2 million and $1.7 million, respectively, on the settlement of the Bruin contracts. In addition, the Company recognized an unrealized loss of $52.8 million and $35.4 million, respectively, for the change in the fair value of the Bruin contracts over the same periods.

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 derivative 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 Enerplus' price risk management positions at August 4, 2021:

Crude Oil Instruments:

Instrument Type(1)(2)	bbls/day	US$/bbl
Jul 1, 2021 – Dec 31, 2021		
WTI Purchased Put	23,000	46.39
WTI Sold Put	23,000	36.39
WTI Sold Call	23,000	56.70
Jan 1, 2022 - Dec 31, 2022		
WTI Purchased Put	17,000	50.00
WTI Sold Put	17,000	40.00
WTI Sold Call	17,000	57.91
Contracts acquired from Bruin(3)		
Jul 1, 2021 – Dec 31, 2021		
WTI Swap	8,465	42.52
Jan 1, 2022 - Dec 31, 2022		
WTI Swap	3,828	42.35
Jan 1, 2023 - Oct 31, 2023		
WTI Swap	250	42.10
WTI Purchased Put	2,000	5.00
WTI Sold Call	2,000	75.00
Nov 1, 2023 - Dec 31, 2023		
WTI Purchased Put	2,000	5.00
WTI Sold Call	2,000	75.00

(1) The total average deferred premium spent on the Company's outstanding crude oil contracts is US$0.84/bbl from July 1, 2021 - December 31, 2021 and US$1.22/bbl from January 1, 2022 - December 31, 2022.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Upon closing of the Bruin Acquisition, Bruin's outstanding crude oil contracts were recorded at a fair value liability of $96.5 million. At June 30, 2021, the balance was a liability of $64.5 million on the Condensed Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired contracts are recognized in Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the date of closing of the Bruin Acquisition.

Natural Gas Instruments:

Instrument Type(1)	MMcf/day	US$/Mcf
Jul 1, 2021 – Oct 31, 2021		
NYMEX Swap	60.0	2.90
NYMEX Purchased Put	40.0	2.75
NYMEX Sold Put	40.0	2.15
NYMEX Sold Call	40.0	3.25
Nov 1, 2021 – Mar 31, 2022		
NYMEX Purchased Put	40.0	3.43
NYMEX Sold Call	40.0	6.00

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

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations and associated net investment, U.S. dollar denominated senior notes, term loan, bank credit facility, cash deposits and working capital. Additionally, Enerplus' crude oil sales and a significant 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, 2021, 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 by the cumulative translation gain or loss on the net investment. At June 30, 2021, US$303.8 million of senior notes outstanding and the US$400 million term loan were designated as net investment hedges. For the three and six months ended June 30, 2021, Other Comprehensive Income/(Loss) included an unrealized gain of $14.7 million and $23.2 million, respectively, on Enerplus' U.S. dollar denominated senior notes and term loan (2020 – $19.5 million gain and $30.6 million loss, respectively).

Interest Rate Risk:

The Company's senior notes bear interest at fixed rates while the term loan and bank credit facility bear interest at floating rates. At June 30, 2021, approximately 31% of Enerplus' debt was based on fixed interest rates and 69% on floating interest rates (December 31, 2020 – 100% fixed), with weighted average interest rates of 4.4% and 1.9%, respectively (December 31, 2020 – 4.4%). At June 30, 2021, Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 16. Enerplus has entered into various equity swaps maturing in 2021 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 volatility in commodity prices, Enerplus is subject to an increased risk of financial loss due to non-performance or insolvency of its counterparties.

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

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, 2021, approximately 79% of Enerplus' marketing receivables were with companies considered investment grade (December 31, 2020 – 82%).

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, 2021 was $5.0 million (December 31, 2020 – $3.6 million).

iii) Liquidity Risk & Capital Management

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

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

At June 30, 2021, Enerplus was in full compliance with all covenants under the bank credit facility, term loan, and outstanding senior notes. If the Company breaches or anticipates breaching its covenants, the Company may be required to repay, refinance, or renegotiate the terms of the debt.

18) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Accounts receivable	$ (80,585)	$ (13,557)	$ (144,753)	$ 67,259
Other assets	(1,408)	207	1,740	(200)
Accounts payable	35,934	34,246	13,158	(25,857)
Non-cash operating activities	$ (46,059)	$ 20,896	$ (129,855)	$ 41,202

b) Changes in Non-Cash Financing Working Capital

($ thousands)	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Non-cash financing activities[1]	$ (2,568)	$ (1)	$ (2,225)	$ 8

(1) Relates to changes in dividends payable and included in dividends on the Condensed Consolidated Statements of Cash Flows.

c) Changes in Non-Cash Investing Working Capital

($ thousands)	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Non-cash investing activities[1]	$ 37,988	$ (63,094)	$ 52,141	$ (26,899)

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

d) Other

($ thousands)	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Cash income taxes paid/(received)	$ 4,237	$ 71	$ 4,242	$ (30,097)
Cash interest paid	15,179	12,966	18,396	16,253

19) SUBSEQUENT EVENT

Effective August 1, 2021, Enerplus participated in the Dakota Access Pipeline expansion with an additional 6,500 bbls/day of firm crude oil transportation. The additional transportation provides access to sell a greater portion of Enerplus' production at U.S. Gulf Coast or Brent pricing.

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(3)(7)(9)
Corporate Director
Toronto, Ontario

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

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

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

Elliott Pew
Corporate Director
Boerne, Texas

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

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

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

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas
President & Chief Executive Officer

Wade D. Hutchings
Senior Vice President & Chief Operating Officer

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

Garth R. Doll
Vice President, Marketing

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

Nathan D. Fisher
Vice President, 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

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

AST Trust Company (Canada)/American Stock Transfer & Trust Company, LLC
Calgary, Alberta
Toll free: 1.800.387.0825

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

950 17th Street, Suite 2200
Denver, Colorado 80202

Telephone: 720.279.5500
Fax: 720.279.5550

ABBREVIATIONS

bbl(s)/day	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
Bcf	billion cubic feet
BOE	barrels of oil equivalent
Brent	crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $U.S. 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

enerPLUS

Enerplus
Dome Tower
Suite 3000, 333 7th Avenue SW
Calgary, Alberta
Canada T2P 2Z1
Toll Free: 1-800-319-6462
www.enerplus.com
investorrelations@enerplus.com