

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

The following discussion and analysis of financial results is dated August 6, 2020 and is to be read in conjunction with:

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

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" at the end of the MD&A for further information. In addition, the following MD&A contains disclosure regarding certain risks and uncertainties associated with Enerplus' business. See "Risk Factors and Risk Management" in this MD&A and in the Annual MD&A and "Risk Factors" in Enerplus' annual information form for the year ended December 31, 2019 (the "Annual Information Form").

**BASIS OF PRESENTATION**

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

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 bbl and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcf") based on 0.167 bbl:1 Mcf. BOE and Mcf 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 Mcf in isolation may be misleading. Unless otherwise stated, all production volumes and realized product prices information is presented on a "Company interest" basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and may not be comparable to information produced by other entities. All references to "liquids" in this MD&A include light and medium crude oil, heavy oil and tight oil (all together referred to as "crude oil") and natural gas liquids on a combined basis.

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

**OVERVIEW**

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

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

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

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

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

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

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

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

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

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

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

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

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

## RESULTS OF OPERATIONS

### Production

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

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

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

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

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

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

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

## Pricing

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

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

(1) Excluding transportation costs, royalties and the effects of commodity derivative instruments.

(2) Based on a weighted average differential for the period.

## CRUDE OIL AND NATURAL GAS LIQUIDS

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

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

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

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

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

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

## NATURAL GAS

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

## FOREIGN EXCHANGE

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

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

## Price Risk Management

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

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

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

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

(1) The total average deferred premium spent on our outstanding hedges is US\$1.75/bbl from July 1, 2020 to December 31, 2020 and US\$0.03/bbl from January 1, 2021 to June 30, 2021.

(2) The sold puts on the put spreads settle annually at the end of 2020.

## ACCOUNTING FOR PRICE RISK MANAGEMENT

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

  

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

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

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At June 30, 2020, the fair value of crude oil contracts was in a net asset position of \$44.0 million. For the three and six months ended June 30, 2020, the change in the fair value of our crude oil contracts resulted in a loss of \$64.4 million and a gain of \$33.9 million, respectively. Our natural gas contracts were settled in the fourth quarter of 2019 and there were no natural gas derivative contracts outstanding during the six months ended June 30, 2020.

## Revenues

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

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

## Royalties and Production Taxes

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



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

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

## Operating Expenses

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

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

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

## Transportation Costs

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

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

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

## Netbacks

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

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 <sup>(1)</sup> \$ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	\$ 25.63	\$ 1.75	\$ 19.53
Royalties and production taxes	(7.18)	(0.35)	(5.15)
Cash operating expenses	(10.45)	(0.25)	(6.84)
Transportation costs	(3.21)	(0.98)	(4.28)
Netback before hedging	\$ 4.79	\$ 0.17	\$ 3.26
Cash hedging gains/(losses)	11.26	—	6.73
Netback after hedging	\$ 16.05	\$ 0.17	\$ 9.99
Netback before hedging (\$ millions)	\$ 22.7	\$ 3.3	\$ 26.0
Netback after hedging (\$ millions)	\$ 76.2	\$ 3.3	\$ 79.5

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

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

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

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

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

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

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



## General and Administrative (“G&A”) Expenses

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

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

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

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

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

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

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

## Interest Expense

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

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

## Foreign Exchange

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

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

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

## Capital Investment

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

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

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

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

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

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

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

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

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

## Impairment

### PP&E

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

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

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

### Goodwill

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

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

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

## Asset Retirement Obligation

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

## Leases

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

## Income Taxes

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

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

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

We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not all or a portion of our deferred income tax assets will not be realized. We have considered available positive and negative evidence including future taxable income and reversing existing temporary differences in making this assessment. This assessment is primarily the result of projecting future taxable income using total proved and probable reserves at forecast average prices and costs. For the six months ended June 30, 2020, a valuation allowance of \$93.6 million was recorded during the first quarter of 2020 related entirely to our Canadian deferred income tax assets. No valuation allowance was recorded for the six months ended June 30, 2019. Our overall net deferred income tax asset was \$367.3 million at June 30, 2020 (December 31, 2019 - \$372.5 million).

## LIQUIDITY AND CAPITAL RESOURCES

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

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

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

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

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

At June 30, 2020, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. We expect to manage our business within these financial ratios during 2020. If we exceed or anticipate exceeding our covenants, we may be required to repay, refinance or renegotiate the terms of the debt. See "Risk Factors – Debt covenants of the Corporation may be exceeded with no ability to negotiate covenant relief" in the Annual Information Form and "Risk Factors and Risk Management" in this MD&A. Our bank credit facility and senior note purchase agreements have been filed under our SEDAR profile at [www.sedar.com](http://www.sedar.com).

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

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

#### Definitions

"Senior debt" is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.

"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended June 30, 2020 was \$62.2 million and \$545.1 million, respectively.

"Total debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.

"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a \$1.1 billion adjustment related to our adoption of U.S. GAAP.

#### Footnotes

(1) See "Non-GAAP Measures" in this MD&A for a reconciliation of adjusted EBITDA to net income.

(2) Senior debt to adjusted EBITDA for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.

(3) Senior debt to consolidated present value of total proved reserves is calculated annually on December 31 based on before tax reserves at forecast prices discounted at 10%.

## Dividends

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

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

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

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

## Shareholders' Capital

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

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

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

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

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

## SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

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

(1) Company interest volumes.

(2) Before transportation costs, royalties and the effects of commodity derivative instruments.

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

(4) Includes share-based compensation expense.



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

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

## QUARTERLY FINANCIAL INFORMATION

(\$ millions, except per share amounts)	Oil and Natural Gas		Net Income/(Loss) Per Share	
	Sales, Net of Royalties	Net Income/(Loss)	Basic	Diluted
<b>2020</b>				
Second Quarter	\$ 122.1	\$ (609.3)	\$ (2.74)	\$ (2.74)
First Quarter	228.1	2.9	0.01	0.01
Total 2020	\$ 350.2	\$ (606.4)	\$ (2.73)	\$ (2.73)
<b>2019</b>				
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)
<b>2018</b>				
Fourth Quarter	\$ 326.7	\$ 249.4	\$ 1.03	\$ 1.02
Third Quarter	373.6	86.9	0.35	0.35
Second Quarter	327.4	12.4	0.05	0.05
First Quarter	265.0	29.6	0.12	0.12
Total 2018	\$ 1,292.7	\$ 378.3	\$ 1.55	\$ 1.53

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

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

## U.S. Filing Status

Pursuant to U.S. securities regulations, we are required to reassess our U.S. securities filing status annually at June 30. As at June 30, 2020, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

## RISK FACTORS AND RISK MANAGEMENT

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

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

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

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

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

## 2020 GUIDANCE

Summary of 2020 Expectations	Target
Capital spending	\$300 million
Average annual production	88,000 - 90,000 BOE/day
Average annual crude oil and natural gas liquids production	49,000 - 50,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	26%
Operating expenses	\$8.25/BOE
Transportation costs	\$4.15/BOE
Cash G&A expenses	\$1.40/BOE
2020 Differential/Basis Outlook <sup>(1)</sup>	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US\$(5.00)/bbl <sup>(2)</sup>
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US\$(0.45)/Mcf

(1) Excluding transportation costs

(2) Guidance is based on the continued operation of DAPL.

## NON-GAAP MEASURES

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

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

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

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

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

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

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

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

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

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

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

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

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

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

#### Reconciliation of Net Income/(Loss) to Adjusted EBITDA<sup>(1)</sup>

(\$ millions)	June 30, 2020
Net income/(loss)	\$ (970.4)
Add:	
Goodwill impairment	653.9
Interest	32.8
Current and deferred tax expense/(recovery)	32.4
DD&A and asset impairment	794.5
Other non-cash charges <sup>(2)</sup>	3.9
Adjusted EBITDA	\$ 547.1

(1) Balances above at June 30, 2020 include the six months ended June 30, 2020 and the third and fourth quarter of 2019.

(2) Includes the change in fair value of commodity derivatives and equity swaps, non-cash SBC expense, non-cash G&A expense and unrealized foreign exchange gains/losses.

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

## INTERNAL CONTROLS AND PROCEDURES

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

## ADDITIONAL INFORMATION

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

## FORWARD-LOOKING INFORMATION AND STATEMENTS

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

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

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

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