Exhibit 99.1

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

The following discussion and analysis of financial results is dated August 8, 2019 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, 2019 and 2018 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2018 and 2017 and for the years ended December 31, 2018, 2017 and 2016; and
- our MD&A for the year ended December 31, 2018 (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.

BASIS OF PRESENTATION

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

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 bbl and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcf. BOE and Mcfe measures are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 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 are 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.

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.

Effective in 2019, Enerplus adopted ASC 842 - Leases. The most significant impact was the recognition of right-of-use ("ROU") assets and lease liabilities on the Condensed Consolidated Balance Sheet for operating leases and additional note disclosures. See Notes 3(a) and 10 to the Interim Financial Statements for further details.

OVERVIEW

Production for the second quarter averaged 100,694 BOE/day, an increase of 14% compared to the first quarter of 2019 and exceeded our second quarter guidance of 97,500 to 100,000 BOE/day. Our crude oil and natural gas liquids production increased by 16% to 52,861 bbls/day from 45,488 bbls/day in the first quarter of 2019, meeting the high end of our second quarter crude oil and natural gas liquids production guidance range of 51,500 to 53,000 bbls/day. The increase in our liquids production was primarily due to our 24.7 net wells brought on-stream during the period in North Dakota. Our natural gas production increased by 11% or 28,432 Mcf/day from the first quarter of 2019 to 287,000 Mcf/day due to outperformance in our Marcellus properties. As a result of higher production in the Marcellus, we are increasing our average annual production guidance range to 99,000 to 102,000 BOE/day (from 97,000 to 101,000 BOE/day). We are also narrowing our average annual crude oil and natural gas liquids guidance to 54,000 to 55,500 bbls/day (from 53,500 to 56,000 bbls/day).

Capital expenditures during the second quarter of $207.2 million were in line with our expectations, with approximately 80% of our capital spending directed to our North Dakota crude oil properties. We are narrowing our 2019 annual capital spending guidance range to $610 – $630 million from $590 – $630 million.

Operating expenses for the quarter were $71.8 million or $7.84/BOE compared to $69.8 million or $8.75/BOE in the first quarter of 2019. The decrease on a per BOE basis was mainly due to increased production in the second quarter of 2019. We are reducing our annual operating cost guidance of $8.00/BOE to $7.90/BOE for 2019, due to the increase in our average annual production guidance.

Cash G&A expenses for the second quarter were $11.5 million or $1.26/BOE, a decrease of 19% on a per BOE basis from $1.55/BOE in the first quarter of 2019. Cash G&A expenses decreased on a per BOE basis, primarily due to higher production volumes during the period. We are reducing our annual guidance of $1.50/BOE to $1.45/BOE for cash G&A expenses for the year.

During the second quarter of 2019, our Bakken crude oil price differential improved to US$3.00/bbl below WTI, compared to US$3.25/bbl below WTI in the first quarter of 2019. Our Marcellus natural gas differential widened to US$0.57/Mcf below NYMEX in the second quarter, compared to US$0.13/Mcf above NYMEX in the first quarter of 2019, due to lower gas prices and a decline in weather-related demand. In addition, our first quarter Marcellus natural gas prices benefited from fixed basis sales at markedly higher levels than the settled benchmarks. We are reducing our full year U.S. Bakken crude oil differential outlook to US$3.25/bbl below WTI from US$4.00/bbl and revising our full year Marcellus natural gas sales price differential outlook to US$0.35/Mcf below NYMEX from US$0.30/Mcf.

As of August 7, 2019, we had approximately 66% of our forecasted crude oil production, net of royalties, hedged for 2019, and approximately 43% of our crude oil production, net of royalties, hedged in 2020, based on 2019 forecasted net production.

We reported net income of $85.1 million in the second quarter of 2019 compared to $19.2 million in the first quarter of 2019. The increase is primarily the result of a $34.0 million increase to revenue, net of royalties, resulting from higher production and a $28.6 million unrealized gain on commodity derivative instruments, compared to an unrealized loss of $95.4 million in the first quarter of 2019.

In the second quarter of 2019, cash flow from operations increased to $237.0 million, compared to $109.0 million in the first quarter of 2019 due to higher production and changes to working capital, most notably, the receipt of the first Alternative Minimum Tax ("AMT") refund of $57.2 million in the second quarter of 2019. Adjusted funds flow in the second quarter increased to $186.0 million from $168.8 million in the first quarter of 2019, as a result of increased production and a current tax recovery of $13.9 million, compared to $5.5 million in the prior period.

During the quarter, we repurchased and cancelled 6,626,783 common shares under our Normal Course Issuer Bid ("NCIB") for total consideration of $70.6 million.

At June 30, 2019, our total debt net of cash was $359.0 million and our net debt to adjusted funds flow ratio was 0.5x.

RESULTS OF OPERATIONS

Production

Average daily production for the second quarter totaled 100,694 BOE/day, an increase of 12,111 BOE/day or 14% compared to first quarter production of 88,583 BOE/day, exceeding our second quarter average production guidance range of 97,500 to 100,000 BOE/day. Crude oil and natural gas liquids production increased by 16% to 52,861 bbls/day from the first quarter, meeting the high end of our second quarter crude oil and natural gas liquids guidance range of 51,500 to 53,000 bbls/day. The increase was due to the 24.7 net wells coming on-stream in North Dakota during the second quarter compared to 3.5 in the prior period. Our natural gas production increased by 11% to 287,000 Mcf/day when compared to our first quarter production of 258,568 Mcf/day, due to strong well performance in our Marcellus properties, where 1.6 net wells were brought on-steam during the period. During the second quarter, we completed the sale of certain Canadian assets with associated production of approximately 350 bbls/day.

For the three and six months ended June 30, 2019, total production increased by 7,811 BOE/day or 8%, and 5,668 BOE/day or 6%, respectively, when compared to the same periods in 2018. Our liquids growth is largely due to our continued capital investment in North Dakota and our increased natural gas production is due to strong well performance in the Marcellus.

Our crude oil and natural gas liquids weighting increased to 52% in the first six months of 2019, from 51% for the same period of 2018, due to continued investment in our North Dakota crude oil properties.

Average daily production volumes for the three and six months ended June 30, 2019 and 2018 are outlined below:

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2019**	**2018**	**% Change**	**2019**	**2018**	**% Change**
Crude oil (bbls/day)	48,141	45,242	6%	44,642	41,364	8%
Natural gas liquids (bbls/day)	4,720	4,808	(2%)	4,552	4,449	2%
Natural gas (Mcf/day)	287,000	256,995	12%	272,863	259,141	5%
Total daily sales (BOE/day)	100,694	92,883	8%	94,671	89,003	6%

As a result of strong well performance, we are increasing our average annual production guidance to 99,000 – 102,000 BOE/day from 97,000 – 101,000 BOE/day and narrowing our average annual crude oil and natural gas liquids guidance to 54,000 – 55,500 bbls/day from 53,500 – 56,000 bbls/day.

Pricing

The prices received for our 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 2019 to the first half of 2018 and other periods indicated:

	Six months ended June 30,						
Pricing (average for the period)	**2019**	**2018**	**Q2 2019**	**Q1 2019**	**Q4 2018**	**Q3 2018**	**Q2 2018**
Benchmarks							
WTI crude oil (US$/bbl)	$ 57.36	$ 65.37	$ 59.81	$ 54.90	$ 58.81	$ 69.50	$ 67.88
Brent (ICE) crude oil (US$/bbl)	66.11	71.04	68.32	63.90	68.08	75.97	74.90
NYMEX natural gas – last day (US$/Mcf)	2.89	2.90	2.64	3.15	3.64	2.90	2.80
USD/CDN average exchange rate	1.33	1.28	1.34	1.33	1.32	1.31	1.29
USD/CDN period end exchange rate	1.31	1.31	1.31	1.33	1.36	1.29	1.31
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 70.82	$ 75.34	$ 74.42	$ 66.56	$ 64.18	$ 83.98	$ 79.98
Natural gas liquids ($/bbl)	18.53	30.36	17.96	19.15	26.72	25.95	32.23
Natural gas ($/Mcf)	3.46	3.09	2.63	4.38	4.28	3.22	2.68
Average differentials							
Bakken DAPL – WTI (US$/bbl)	$ (2.64)	$ (2.37)	$ (2.36)	$ (2.93)	$ (9.22)	$ (0.97)	$ (2.78)
Brent (ICE) – WTI (US$/bbl)	8.75	5.67	8.51	9.00	9.27	6.47	7.02
MSW Edmonton – WTI (US$/bbl)	(4.74)	(5.67)	(4.63)	(4.85)	(26.30)	(6.83)	(5.45)
WCS Hardisty – WTI (US$/bbl)	(11.48)	(21.78)	(10.67)	(12.29)	(39.43)	(22.25)	(19.27)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.33)	(0.79)	(0.43)	(0.22)	(0.39)	(0.61)	(0.91)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	0.68	1.46	(0.31)	1.67	0.20	(0.12)	(0.18)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI (US$/bbl)	$ (3.10)	$ (3.34)	$ (3.00)	$ (3.25)	$ (5.60)	$ (2.54)	$ (3.42)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.25)	(0.45)	(0.57)	0.13	(0.34)	(0.48)	(0.69)
Canada crude oil – WTI (US$/bbl)	(10.21)	(18.52)	(9.99)	(10.42)	(33.27)	(16.61)	(16.31)

(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 average realized crude oil sales price for the second quarter of 2019 averaged $74.42/bbl, an increase of 12% compared to the previous quarter, and directionally in line with changes in WTI benchmark pricing. Both Bakken and Canadian crude oil price differentials improved slightly from the first quarter of 2019. Our realized Bakken price differential improved by 8% during the quarter to average US$3.00/bbl below WTI. 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 our firm capacity on the Dakota Access Pipeline. For the remainder of 2019, we have physical sales contracts in place for an average of 26,300 bbls/day of Bakken crude oil production with fixed differentials averaging approximately US$2.66/bbl below WTI. Based on year to date price realizations and an improved outlook for Bakken differentials in the second half of the year, we are revising our full year Bakken differential guidance to US$3.25/bbl below WTI (from US$4.00/bbl).

Our realized price differential for our Canadian crude oil production improved by US$0.43/bbl compared to the previous quarter. Canadian crude oil prices continue to be supported by the Alberta Government production curtailment program. We have fixed differential hedges in place for 1,500 bbls/day of our Canadian heavy crude oil production at an average differential of US$14.83/bbl below WTI for the remainder of 2019.

Our realized price for natural gas liquids averaged $17.96/bbl during the second quarter, which represents a 6% decrease compared to the previous quarter. The reduction is mainly due to the continued deterioration in propane and butane pricing.

NATURAL GAS

Our average realized natural gas price during the second quarter of 2019 decreased by 40% compared to the first quarter of 2019, to average $2.63/Mcf, while NYMEX benchmark pricing decreased by 16%. With a significant portion of our sales tied to the Transco Zone 6 Non-New York market, the change in seasonal demand from winter to spring drove lower quarter over quarter pricing in this region. This along with our first quarter physical sales at markedly higher levels than the settled benchmarks resulted in a decline in our realized sales price in the second quarter when compared to the first quarter of 2019. As expected, our realized Marcellus sales differential widened to US$0.57/Mcf below NYMEX during the second quarter. We are revising our full year differential guidance for the Marcellus of US$0.30/Mcf below NYMEX to US$0.35/Mcf. We continue to expect our realized prices to improve from current levels as seasonal heating demand increases significantly in the New York markets during the fourth quarter.

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 was weaker during the first six months of 2019 with an average exchange rate of 1.33 US/CDN compared to 1.28 US/CDN for the same period in 2018. However, when compared to the exchange rate at December 31, 2018, the Canadian dollar strengthened relative to the U.S. dollar.

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 7, 2019, we have hedged 24,500 bbls/day of crude oil, which represents approximately 66% of our forecasted crude oil production, after royalties, for the remainder of 2019. For 2020, we have hedged 16,000 bbls/day, which represents approximately 43% of crude oil production, after royalties, based off our 2019 forecast. Our crude oil hedges in 2019 are all three-way collars, which consist of a sold put, a purchased put and a sold call. Our crude oil hedges in 2020 are all put spreads with no cap on upside participation. With both three-way collars and put spreads, if WTI prices settle below the sold put strike price, these positions provide a limited amount of protection above the WTI settled price equal 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.

We have entered into offsetting purchase transactions on our NYMEX natural gas hedges through October 2019. This has effectively locked in gains of $0.51/Mcf on our original NYMEX hedges through this term.

The following is a summary of our financial contracts in place at August 7, 2019, expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)[1]		
	Jul 1, 2019 – Sep 30, 2019	**Oct 1, 2019 – Dec 31, 2019**	**Jan 1, 2020 – Dec 31, 2020**
Three Way Collars[2]			
Sold Puts	$ 44.64	$ 44.64	—
%	66%	66%	—
Purchased Puts	$ 54.81	$ 54.81	—
%	66%	66%	—
Sold Calls	$ 65.95	$ 65.99	—
%	66%	66%	—
Put Spreads[2]			
Sold Puts	—	—	$ 46.88
%	—	—	43%
Purchased Puts	—	—	$ 57.50
%	—	—	43%

(1) Based on weighted average price (before premiums) assuming average annual production of 100,500 BOE/day, which is the mid-point of our annual 2019 guidance, less royalties and production taxes of 25%. A portion of the sold puts are settled annually rather than monthly.
(2) The total average deferred premium on outstanding hedges is US$2.00/bbl from July 1, 2019 to December 31, 2020.

	NYMEX Natural Gas (US$/Mcf)[1]	
	Jul 1, 2019 – Jul 31, 2019	**Aug 1, 2019 – Oct 31, 2019**
Swaps		
Sold Swaps	$2.85	$2.85
%	44%	44%
Bought Swaps	$2.34	$2.34
%	29%	44%

(1) Based on weighted average price (before premiums) assuming average annual production of 100,500 BOE/day, which is the mid-point of our annual 2019 guidance, less royalties and production taxes of 25%.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Cash gains/(losses):				
Crude oil	$ (5.9)	$ (20.1)	$ (7.8)	$ (26.4)
Natural gas	4.7	0.8	17.2	17.3
Total cash gains/(losses)	$ (1.2)	$ (19.3)	$ 9.4	$ (9.1)
Non-cash gains/(losses):				
Crude oil	$ 23.6	$ (70.9)	$ (63.3)	$ (100.8)
Natural gas	5.0	(0.8)	(3.5)	(1.5)
Total non-cash gains/(losses)	$ 28.6	$ (71.7)	$ (66.8)	$ (102.3)
Total gains/(losses)	$ 27.4	$ (91.0)	$ (57.4)	$ (111.4)

	Three months ended June 30,		**Six months ended June 30,**	
(Per BOE)	**2019**	**2018**	**2019**	**2018**
Total cash gains/(losses)	$ (0.13)	$ (2.28)	$ 0.55	$ (0.57)
Total non-cash gains/(losses)	3.12	(8.48)	(3.90)	(6.35)
Total gains/(losses)	$ 2.99	$ (10.76)	$ (3.35)	$ (6.92)

During the second quarter of 2019, we realized cash losses of $5.9 million on our crude oil contracts and cash gains of $4.7 million on our natural gas contracts. In comparison, during the second quarter of 2018, we realized cash losses of $20.1 million on our crude oil contracts and cash gains of $0.8 million on our natural gas contracts. Cash losses in the second quarter of 2019 on our crude oil contracts were primarily due to premiums paid on expiring three-way collars. Cash gains on our natural gas contracts were primarily due to natural gas prices falling below the swap level.

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 the end of the second quarter of 2019, the fair value of our crude oil contracts was in a net asset position of $17.2 million and the fair value of our natural gas contracts was in a net asset position of $7.4 million. For the three and six months ended June 30, 2019, the change in the fair value of our crude oil contracts represented gains of $23.6 million and losses of $63.3 million, respectively, and our natural gas contracts represented gains of $5.0 million and losses of $3.5 million, respectively.

Revenues

	Three months ended June 30,		**Six months ended June 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Oil and natural gas sales	$ 403.2	$ 406.8	$ 759.6	$ 735.3
Royalties	(81.7)	(79.4)	(150.7)	(142.9)
Oil and natural gas sales, net of royalties	$ 321.5	$ 327.4	$ 608.9	$ 592.4

Oil and natural gas sales, net of royalties, for the three and six months ended June 30, 2019, were $321.5 million and $608.9 million, respectively, a decrease of 2% and an increase of 3% from the same periods in 2018. The decrease in revenue during the second quarter of 2019 was a result of lower crude oil and natural gas liquids prices, partially offset by higher production volumes compared to the same period in 2018. The increase in revenue during the six month period ended June 30, 2019 was a result of higher production volumes and natural gas prices, partially offset by lower crude oil and natural gas liquids prices compared to the same period in 2018.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Royalties	$ 81.7	$ 79.4	$ 150.7	$ 142.9
Per BOE	$ 8.92	$ 9.40	$ 8.79	$ 8.87
Production taxes	$ 21.4	$ 22.6	$ 36.1	$ 38.8
Per BOE	$ 2.34	$ 2.68	$ 2.11	$ 2.41
Royalties and production taxes	$ 103.1	$ 102.0	$ 186.8	$ 181.7
Per BOE	$ 11.26	$ 12.08	$ 10.90	$ 11.28
Royalties and production taxes (% of oil and natural gas sales)	26%	25%	25%	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. During the three and six months ended June 30, 2019, royalties and production taxes increased slightly to $103.1 million and $186.8 million, respectively, from $102.0 million and $181.7 million for the same periods in 2018, primarily due to higher U.S. crude oil sales.

We are maintaining our annual average royalty and production tax rate guidance of 25% for 2019.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Cash operating expenses	$ 71.8	$ 61.0	$ 141.6	$ 114.7
Non-cash (gains)/losses[1]	—	(0.1)	—	(0.1)
Total operating expenses	$ 71.8	$ 60.9	$ 141.6	$ 114.6
Per BOE	$ 7.84	$ 7.20	$ 8.26	$ 7.12

(1) Non-cash (gains)/losses on fixed price electricity swaps.

For the three and six months ended June 30, 2019, operating expenses were $71.8 million or $7.84/BOE and $141.6 million or $8.26/BOE, respectively, representing an increase of $10.9 million and $27.0 million from the same periods in 2018. The increase is mainly attributable to our higher North Dakota crude oil and natural gas liquids volumes, higher gas facility charges and well service activity in 2019.

We are reducing our annual operating cost guidance of $8.00/BOE to $7.90/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Transportation costs	$ 36.8	$ 30.1	$ 68.1	$ 57.0
Per BOE	$ 4.02	$ 3.56	$ 3.97	$ 3.54

For the three and six months ended June 30, 2019, transportation costs were $36.8 million or $4.02/BOE and $68.1 million or $3.97/BOE, respectively, compared to our annual guidance of $4.00/BOE. During the same periods in 2018, transportation costs were $30.1 million or $3.56/BOE and $57.0 million or $3.54/BOE. The increase is due to additional crude oil firm transportation commitments that provide access to sell a portion of our production at the U.S. Gulf Coast or Brent pricing that commenced March 1, 2019 and a weaker Canadian dollar when compared to the prior periods.

We are maintaining our annual guidance for transportation costs of $4.00/BOE.

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

	Three months ended June 30, 2018		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	53,624 BOE/day	235,554 Mcfe/day	92,883 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 71.65	$ 2.67	$ 48.13
Royalties and production taxes	(18.66)	(0.51)	(12.08)
Cash operating expenses	(10.95)	(0.35)	(7.21)
Transportation costs	(2.41)	(0.86)	(3.56)
Netback before hedging	$ 39.63	$ 0.95	$ 25.28
Cash hedging gains/(losses)	(4.12)	0.04	(2.28)
Netback after hedging	$ 35.51	$ 0.99	$ 23.00
Netback before hedging ($ millions)	$ 193.4	$ 20.3	$ 213.7
Netback after hedging ($ millions)	$ 173.3	$ 21.1	$ 194.4

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

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

Netbacks by Property Type	Six months ended June 30, 2018 Crude Oil		Natural Gas		Total
Average Daily Production	48,890 BOE/day		240,678 Mcfe/day		89,003 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)		(per Mcfe)		(per BOE)
Oil and natural gas sales	$ 67.73	$	3.12	$	45.65
Royalties and production taxes	(17.67)		(0.58)		(11.28)
Cash operating expenses	(10.87)		(0.42)		(7.12)
Transportation costs	(2.26)		(0.86)		(3.54)
Netback before hedging	$ 36.93	$	1.26	$	23.71
Cash hedging gains/(losses)	(2.99)		0.40		(0.57)
Netback after hedging	$ 33.94	$	1.66	$	23.14
Netback before hedging ($ millions)	$ 326.8	$	55.1	$	381.9
Netback after hedging ($ millions)	$ 300.4	$	72.4	$	372.8

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

Crude oil netbacks before hedging for the three and six months ended June 30, 2019 were lower compared to the same periods in 2018 primarily due to weaker realized prices and higher operating and transportation expenses. Natural gas netbacks before hedging were higher for the three and six months ended June 30, 2019 compared to the same periods in 2018 mainly due to higher realized prices. For the three and six months ended June 30, 2019, our crude oil properties accounted for 87% and 79% of our total netback before hedging, respectively, compared to 91% and 86% during the same periods in 2018.

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 to the Interim Financial Statements for further details.

($ millions)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Cash:				
G&A expense	$ 11.5	$ 12.1	$ 23.9	$ 25.3
Share-based compensation expense	(0.6)	0.5	0.7	2.4
Non-Cash:				
Share-based compensation expense	4.3	5.0	12.3	14.1
Equity swap loss/(gain)	0.2	(0.4)	0.1	(1.4)
G&A expense	0.3	—	0.4	—
Total G&A expenses	$ 15.7	$ 17.2	$ 37.4	$ 40.4

(Per BOE)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Cash:				
G&A expense	$ 1.26	$ 1.44	$ 1.39	$ 1.57
Share-based compensation expense	(0.07)	0.05	0.04	0.16
Non-Cash:				
Share-based compensation expense	0.47	0.59	0.72	0.87
Equity swap loss/(gain)	0.03	(0.04)	0.01	(0.09)
G&A expense	0.03	—	0.02	—
Total G&A expenses	$ 1.72	$ 2.04	$ 2.18	$ 2.51

For the three and six months ended June 30, 2019, cash G&A expenses were $11.5 million or $1.26/BOE and $23.9 million or $1.39/BOE, respectively, compared to $12.1 million or $1.44/BOE and $25.3 million or $1.57/BOE for the same periods in 2018. Cash G&A expenses decreased on a per BOE basis compared to the same periods in 2018, due to higher production.

During the second quarter of 2019, we reported a cash SBC recovery of $0.6 million due to the decrease in our share price on outstanding deferred share units. In comparison, during the same period of 2018, we recorded cash SBC expense of $0.5 million due to an increase in our share price on outstanding deferred share units. We recorded non-cash SBC expense of $4.3 million or $0.47/BOE in the second quarter of 2019, a decrease from an expense of $5.0 million or $0.59/BOE during the same period in 2018.

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. In the second quarter, we recorded a non-cash mark-to-market loss of $0.2 million on these hedges due to the decrease in our share price, compared to a gain of $0.4 million recorded for the same period in 2018. We had 264,000 units outstanding, hedged at a weighted average price of $17.82 per share at June 30, 2019.

Based on higher annual production levels we are lowering our annual cash G&A guidance to $1.45/BOE from $1.50/BOE.

Interest Expense

For the three and six months ended June 30, 2019, we recorded total interest expense of $8.7 million and $17.1 million, respectively, compared to $9.2 million and $18.4 million for the same periods in 2018. The decrease in interest expense for the three and six months ended June 30, 2019 compared to the same periods in 2018 was primarily due to the repayment of a portion of our 2009 and 2012 senior notes, partially offset by a weaker Canadian dollar on our U.S. dollar denominated interest expense.

At June 30, 2019, all of our debt was based on fixed interest rates, with a weighted average interest rate of 4.7%. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Realized:				
Foreign exchange (gain)/loss on settlements	$ 0.1	$ 0.2	$ —	$ 0.3
Translation of U.S. dollar cash held in Canada (gain)/loss	4.1	(3.7)	9.3	(11.0)
Unrealized (gain)/loss	(16.5)	12.4	(33.6)	30.0
Total foreign exchange (gain)/loss	$ (12.3)	$ 8.9	$ (24.3)	$ 19.3
USD/CDN average exchange rate	1.34	1.29	1.33	1.28
USD/CDN period end exchange rate	1.31	1.31	1.31	1.31

For the three and six months ended June 30, 2019, we recorded foreign exchange gains of $12.3 million and $24.3 million, respectively, compared to losses of $8.9 million and $19.3 million for the same periods in 2018. Realized 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 gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. Comparing the period end exchange rate at June 30, 2019 to December 31, 2018, the Canadian dollar strengthened relative to the U.S. dollar, resulting in an unrealized gain of $33.6 million. See Note 13 to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Capital spending(1)	$ 207.2	$ 177.1	$ 368.0	$ 328.6
Office capital(1)	2.1	2.3	3.3	3.7
Line fill	—	—	5.1	—
Sub-total	209.3	179.4	376.4	332.3
Property and land acquisitions	$ 1.9	$ 2.4	$ 4.9	$ 14.7
Property divestments	(9.6)	0.2	(10.1)	(6.8)
Sub-total	(7.7)	2.6	(5.2)	7.9
Total	$ 201.6	$ 182.0	$ 371.2	$ 340.2

(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, 2019 totaled $207.2 million and $368.0 million, respectively, compared to the spending of $177.1 million and $328.6 million for the same periods in 2018. The increase in spending is in line with our strategy to deliver production and liquids growth through 2019. During the second quarter, we spent $186.6 million on our U.S. crude oil properties, $13.7 million on our Marcellus natural gas assets and $6.1 million on our Canadian waterflood properties. During the six months ended June 30, 2019, we spent $5.1 million on line fill to meet the requirements of a multi-year transportation contract, which began in March 2019.

In the second quarter of 2019, we completed $1.9 million in property and land acquisitions, which included minor interests in leases and undeveloped land, compared to $2.4 million for the same period in 2018. Property divestments for the three months ended June 30, 2019 were $9.6 million, which primarily related to the divestment of properties in Southeastern Saskatchewan with associated production of approximately 350 bbls/day.

We are narrowing our 2019 annual capital spending guidance range to $610 million – $630 million from $590 million – $630 million.

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

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2019	2018	2019	2018
DD&A expense	$ 88.3	$ 73.2	$ 164.2	$ 137.2
Per BOE	$ 9.64	$ 8.66	$ 9.58	$ 8.52

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three and six months ended June 30, 2019, DD&A increased to $88.3 million and $164.2 million, respectively, compared to $73.2 million and $137.2 million for the same periods in 2018, as a result of additional U.S. production with higher depletion rates and a weaker Canadian dollar.

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 our 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 5.55%, to be $127.1 million at June 30, 2019, compared to 5.59% and $126.1 million at December 31, 2018. For the three and six months ended June 30, 2019, asset retirement obligation settlements were $0.5 million and $5.9 million, respectively, compared to $2.1 million and $5.4 million during the same periods in 2018. See Note 9 to the Interim Financial Statements for further details.

Leases

On January 1, 2019, we adopted ASU 842 – *Leases*, which requires the recognition of 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 included on our balance sheet are based on the present value of lease payments over the lease term. Total ROU assets included on our balance sheet represent our right to use an underlying asset for the lease term. At June 30, 2019, our total lease liability was $61.1 million. In addition, ROU assets of $60.7 million were recorded, which equates to our lease liabilities less non-cash lease incentives. See Note 3(a) and Note 10 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2019	2018	2019	2018
Current tax expense/(recovery)	$ (13.9)	$ 0.1	$ (19.5)	$ 0.1
Deferred tax expenses/(recovery)	48.8	3.2	30.9	15.7
Total tax expense/(recovery)	$ 34.9	$ 3.3	$ 11.4	$ 15.8

For the three and six months ended June 30, 2019, we recorded a current tax recovery of $13.9 and $19.5 million, respectively, compared to an expense of $0.1 million for each of the same periods in 2018. The recoveries primarily relate to the favorable settlement of a tax dispute in Canada in the second quarter of 2019 and the reversal of the reserve recorded at December 31, 2018 for the sequestered portion of our U.S. AMT refund in the first quarter of 2019.

For the three and six months ended June 30, 2019, we recorded deferred tax expense of $48.8 million and $30.9 million, respectively, compared to an expense of $3.2 million and $15.7 million, for the same periods in 2018. The increase in the deferred tax expense during the second quarter was primarily due to a $26.3 million expense recorded for the remeasurement of our Canadian net deferred income tax asset for the change in the Alberta corporate income tax rate from 12% to 8% by 2022. See Note 14 to the Interim Financial Statements for further details.

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our 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, 2019, our senior debt to adjusted EBITDA ratio was 0.8x and our net debt to adjusted funds flow ratio was 0.5x. 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 our liquidity.

Total debt net of cash at June 30, 2019 was $359.0 million, an increase of 8% compared to $333.5 million at December 31, 2018. Total debt was comprised of $611.5 million of senior notes less $252.5 million in cash. During the second quarter, we repaid a portion of our 2009 and 2012 senior notes, resulting in a $59.4 million decrease to our outstanding debt.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 116% and 110% for the three and six months ended June 30, 2019, respectively, compared to 107% and 106% for the same periods in 2018.

For the three months ended June 30, 2019, the Company repurchased and cancelled approximately 6.6 million shares under our NCIB for a total cost of $70.6 million. In total in 2019, the Company has allocated $90.4 million in capital to the repurchase and cancellation of approximately 8.4 million shares under our current and previous NCIB.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, increased to $269.3 million at June 30, 2019 from $143.1 million at December 31, 2018. This increase is primarily due to the reclassification of a portion of our 2009 and 2012 senior notes from long-term debt to current liabilities and an increase in accounts payable due to higher capital spending in the second quarter of 2019 when compared to the fourth quarter of 2018. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, cash flow from operations and our $800 million bank credit facility. We have sufficient liquidity to meet our financial commitments, as disclosed under "Commitments" in the Annual MD&A.

At June 30, 2019, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed under our SEDAR profile at www.sedar.com.

Our net debt to adjusted funds flow remains at 0.5x and the following table lists our financial covenants as at June 30, 2019:

Covenant Description		June 30, 2019
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	0.8x
Total debt to adjusted EBITDA (1)	4.0x	0.8x
Total debt to capitalization	50%	17%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	0.8x
Senior debt to consolidated present value of total proved reserves(3)	60%	18%
	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, 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, 2019 was $176.6 million and $767.5 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, 2019	2018	Six months ended June 30, 2019	2018
Dividends to shareholders[1]	$ 7.0	$ 7.3	$ 14.2	$ 14.7
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, 2019, we reported total dividends of $7.0 million or $0.03 per share and $14.2 million or $0.06 per share, respectively, compared to $7.3 million or $0.03 per share and $14.7 million or $0.06 per share for the same periods in 2018.

The dividend is part of our strategy to return capital to our 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, 2019	2018
Share capital ($ millions)	$ 3,225.6	$ 3,415.0
Common shares outstanding (thousands)	231,616	244,984
Weighted average shares outstanding – basic (thousands)	237,197	244,369
Weighted average shares outstanding – diluted (thousands)	239,947	249,367

For the six months ended June 30, 2019, a total of 1,007,234 units vested pursuant to our treasury settled LTI plans (2018 – 2,539,498). In total, 564,000 shares were issued from treasury and $4.4 million was transferred from paid-in capital to share capital (2018 – 2,539,498; $23.4 million). We elected to cash settle the remaining units related to the required tax withholdings (2019 – $5.0 million, 2018 – nil).

For the six months ended June 30, 2019, no shares were issued pursuant to our stock option plan, resulting in no additional share capital (2018 – 315,843; $4.3 million).

On March 21, 2019, Enerplus announced the renewal of its NCIB to purchase up to 16,673,015 common shares, representing 7% of the "public float" of Enerplus (within the meaning under the rules of the Toronto Stock Exchange (the "TSX")) through the facilities of the TSX, the New York Stock Exchange and/or alternative Canadian trading systems during the 12-month period ending March 25, 2020.

During the six months ended June 30, 2019, the Company repurchased 8,358,821 common shares under the previous and current NCIB at an average price of $10.80 per share, for total consideration of $90.4 million. Of the amount paid, $116.4 million was charged to share capital and $26.0 million was credited to accumulated deficit. Subsequent to the quarter and up to August 7, 2019, the Company repurchased 981,266 common shares under the NCIB at an average price of $8.97 per share, for total consideration of $8.8 million.

On May 23, 2019, we filed a short form base shelf prospectus (the "Shelf Prospectus") with securities regulatory authorities in each of the provinces 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 in place.

At August 7, 2019, we had 230,635,015 common shares outstanding. In addition, an aggregate of 7,958,372 common shares may be issued to settle outstanding grants under the Performance Share Unit ("PSU"), Restricted Share Unit, and stock option plans, assuming the maximum payout 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, 2019 Canada	U.S.	Total	Three months ended June 30, 2018 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	8,749	39,392	48,141	9,212	36,030	45,242
Natural gas liquids (bbls/day)	931	3,789	4,720	1,055	3,753	4,808
Natural gas (Mcf/day)	23,120	263,880	287,000	29,151	227,844	256,995
Total average daily production (BOE/day)	13,533	87,161	100,694	15,126	77,757	92,883
Pricing[2]						
Crude oil (per bbl)	$ 67.12	$ 76.04	$ 74.42	$ 66.58	$ 83.41	$ 79.98
Natural gas liquids (per bbl)	25.31	16.16	17.96	50.20	27.18	32.23
Natural gas (per Mcf)	1.82	2.71	2.63	2.07	2.76	2.68
Capital Expenditures						
Capital spending	$ 7.0	$ 200.2	$ 207.2	$ 11.4	$ 165.7	$ 177.1
Acquisitions	1.1	0.8	1.9	1.0	1.4	2.4
Divestments	(9.4)	(0.2)	(9.6)	0.2	—	0.2
Netback[3] Before Hedging						
Oil and natural gas sales	$ 60.1	$ 343.1	$ 403.2	$ 66.9	$ 339.9	$ 406.8
Royalties	(12.7)	(69.0)	(81.7)	(10.7)	(68.7)	(79.4)
Production taxes	(0.2)	(21.2)	(21.4)	(0.7)	(21.9)	(22.6)
Cash operating expenses	(17.5)	(54.3)	(71.8)	(17.7)	(43.3)	(61.0)
Transportation costs	(2.6)	(34.2)	(36.8)	(2.8)	(27.3)	(30.1)
Netback before hedging	$ 27.1	$ 164.4	$ 191.5	$ 35.0	$ 178.7	$ 213.7
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (27.4)	$ —	$ (27.4)	$ 91.0	$ —	$ 91.0
Total G&A[4]	(1.9)	17.6	15.7	6.3	10.9	17.2
Current income tax expense/(recovery)	(13.9)	—	(13.9)	—	0.1	0.1

($ millions, except per unit amounts)	Six months ended June 30, 2019 Canada	U.S.	Total	Six months ended June 30, 2018 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	8,873	35,769	44,642	9,362	32,002	41,364
Natural gas liquids (bbls/day)	957	3,595	4,552	1,151	3,298	4,449
Natural gas (Mcf/day)	23,730	249,133	272,863	31,131	228,010	259,141
Total average daily production (BOE/day)	13,785	80,886	94,671	15,701	73,302	89,003
Pricing[2]						
Crude oil (per bbl)	$ 63.06	$ 72.75	$ 70.82	$ 59.63	$ 79.94	$ 75.34
Natural gas liquids (per bbl)	30.71	15.29	18.53	47.46	24.39	30.36
Natural gas (per Mcf)	3.26	3.48	3.46	2.63	3.16	3.09
Capital Expenditures						
Capital spending	$ 24.5	$ 343.5	$ 368.0	$ 24.6	$ 304.0	$ 328.6
Acquisitions	2.1	2.8	4.9	2.1	12.6	14.7
Divestments	(9.5)	(0.6)	(10.1)	(0.7)	(6.1)	(6.8)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 121.9	$ 637.7	$ 759.6	$ 127.6	$ 607.7	$ 735.3
Royalties	(21.7)	(129.0)	(150.7)	(20.7)	(122.2)	(142.9)
Production taxes	(0.9)	(35.2)	(36.1)	(1.5)	(37.3)	(38.8)
Cash operating expenses	(38.4)	(103.2)	(141.6)	(38.2)	(76.5)	(114.7)
Transportation costs	(5.3)	(62.8)	(68.1)	(5.8)	(51.2)	(57.0)
Netback before hedging	$ 55.6	$ 307.5	$ 363.1	$ 61.4	$ 320.5	$ 381.9
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 57.4	$ —	$ 57.4	$ 111.4	$ —	$ 111.4
Total G&A[4]	11.3	26.1	37.4	21.7	18.7	40.4
Current income tax expense/(recovery)	(14.0)	(5.5)	(19.5)	—	0.1	0.1

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

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2019				
Second Quarter	$ 321.4	$ 85.1	$ 0.36	$ 0.36
First Quarter	287.5	19.2	0.08	0.08
Total 2019	$ 608.9	$ 104.3	$ 0.44	$ 0.43
2018				
Fourth Quarter	$ 326.7	$ 249.4	$ 1.03	$ 1.02
Third Quarter	373.6	86.9	0.35	0.35
Second Quarter	327.4	12.4	0.05	0.05
First Quarter	265.0	29.6	0.12	0.12
Total 2018	$ 1,292.7	$ 378.3	$ 1.55	$ 1.53
2017				
Fourth Quarter	$ 271.1	$ 15.3	$ 0.06	$ 0.06
Third Quarter	196.1	16.1	0.07	0.07
Second Quarter	225.7	129.3	0.53	0.52
First Quarter	227.8	76.3	0.32	0.31
Total 2017	$ 920.7	$ 237.0	$ 0.98	$ 0.96

Oil and natural gas sales, net of royalties, increased by $34.0 million in the second quarter of 2019 compared to the first quarter of 2019, due to increased production volumes. Net income increased in the second quarter of 2019 due to increased sales and a gain of $27.4 million on commodity derivative instruments, compared to a loss of $84.9 million during the first quarter of 2019.

Oil and natural gas sales, net of royalties, improved in 2018 compared to 2017 due to an increase in realized commodity prices and a higher weighting of crude oil and natural gas liquids as a proportion of total production. As a result, net income also improved in 2018, excluding the effects of a gain which was recorded on asset divestments in the second quarter of 2017.

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, 2019, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

2019 UPDATED GUIDANCE

We are increasing our average annual production guidance to 99,000 – 102,000 BOE/day and revising our average annual crude oil and natural gas liquids guidance to 54,000 – 55,500 bbls/day.

We are narrowing our 2019 capital spending guidance to $610 – $630 million from our previous range of $590 – $630 million. With higher average annual production, we are reducing our annual operating expense guidance to $7.90/BOE from $8.00/BOE and reducing our annual cash G&A guidance to $1.45/BOE from $1.50/BOE.

We are decreasing our full year Bakken differential guidance to US$3.25/bbl below WTI from US$4.00/bbl. We are also increasing our full year Marcellus differential guidance to US$0.35/Mcf below NYMEX from $0.30/Mcf.

All other guidance targets remain unchanged. This guidance does not include any additional acquisitions or divestments.

Summary of 2019 Expectations	Target
Capital spending	$610 - $630 million (from $590 - $630 million)
Average annual production	99,000 - 102,000 BOE/day (from 97,000 - 101,000 BOE/day)
Average annual crude oil and natural gas liquids production	54,000 - 55,500 bbls/day (from 53,500 - 56,000 bbls/day)
Average royalty and production tax rate (% of gross sales, before transportation)	25%
Operating expenses	$7.90/BOE (from $8.00/BOE)
Transportation costs	$4.00/BOE
Cash G&A expenses	$1.45/BOE (from $1.50/BOE)

2019 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.25)/bbl (from US$(4.00)/bbl)
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.35)/Mcf (from US$(0.30)/Mcf)

(1) Excludes transportation costs.

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 our crude oil and natural gas assets. Netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating expenses and transportation costs.

Calculation of Netback	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Oil and natural gas sales	$ 403.2	$ 406.8	$ 759.6	$ 735.3
Less:				
Royalties	(81.7)	(79.4)	(150.7)	(142.9)
Production taxes	(21.4)	(22.6)	(36.1)	(38.8)
Cash operating expenses	(71.8)	(61.0)	(141.6)	(114.7)
Transportation costs	(36.8)	(30.1)	(68.1)	(57.0)
Netback before hedging	$ 191.5	$ 213.7	$ 363.1	$ 381.9
Cash gains/(losses) on derivative instruments	(1.2)	(19.3)	9.4	(9.1)
Netback after hedging	$ 190.3	$ 194.4	$ 372.5	$ 372.8

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

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Cash flow from operating activities	$ 237.0	$ 141.8	$ 345.9	$ 301.1
Asset retirement obligation expenditures	0.5	2.0	5.9	5.4
Changes in non-cash operating working capital	(51.5)	29.9	3.0	22.4
Adjusted funds flow	$ 186.0	$ 173.7	$ 354.8	$ 328.9

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

Calculation of Free Cash Flow	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Adjusted funds flow	$ 186.0	$ 173.7	$ 354.8	$ 328.9
Capital spending	(207.2)	(177.1)	(368.0)	(328.6)
Free cash flow	$ (21.2)	$ (3.4)	$ (13.2)	$ 0.3

"Adjusted net income" 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 is calculated as net income adjusted for unrealized derivative instrument gain/loss, unrealized foreign exchange gain/loss, the tax effect of these items and the impact of statutory changes to the Company's corporate tax rate.

Calculation of Adjusted Net Income	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Net income/(loss)	$ 85.1	$ 12.4	$ 104.3	$ 42.0
Unrealized derivative instrument (gain)/loss	(28.4)	71.2	67.0	100.8
Unrealized foreign exchange (gain)/loss	(16.5)	12.4	(33.6)	30.0
Tax effect on above items	7.8	(19.1)	(17.1)	(27.5)
Income tax rate adjustment on deferred taxes	26.3	—	26.3	—
Adjusted net income	$ 74.3	$ 76.9	$ 146.9	$ 145.3

"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 our adjusted payout ratio as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Dividends	$ 7.0	$ 7.3	$ 14.2	$ 14.7
Capital, office expenditures and line fill	209.3	179.4	376.4	332.3
Sub-total	$ 216.3	$ 186.7	$ 390.6	$ 347.0
Adjusted funds flow	$ 186.0	$ 173.7	$ 354.8	$ 328.9
Adjusted payout ratio (%)	116%	107%	110%	106%

“Adjusted EBITDA” is used by Enerplus and its lenders to determine compliance with financial covenants under its bank credit facility and outstanding senior notes.

Reconciliation of Net Income to Adjusted EBITDA(1)	
($ millions)	**June 30, 2019**
Net income/(loss)	$ 440.5
Add:	
Interest	35.5
Current and deferred tax expense/(recovery)	98.8
DD&A and asset impairment	331.3
Other non-cash charges(2)	(138.6)
Adjusted EBITDA	$ 767.5

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at June 30, 2019 include the six months ended June 30, 2019 and the third and fourth quarter of 2018.
(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, 2019, 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, 2019 and ended June 30, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected 2019 average production volumes, timing thereof and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our adjusted funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management program in 2019 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash G&A, share-based compensation and financing expenses; expected operating and transportation costs; our anticipated shares repurchases under current and future normal course issuer bids; capital spending levels in 2019 and impact thereof on our production levels and land holdings; potential future asset and goodwill impairments, as well as relevant factors that may affect such impairments; 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; our future acquisitions and dispositions, expecting timing thereof and use of proceeds therefrom; 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 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; the availability of third party services; and the extent of our liabilities. In addition, our updated 2019 guidance contained in this MD&A is based on the rest of the year prices of: a WTI price of US$56.00/bbl, a NYMEX price of US$2.30/Mcf, and a USD/CDN exchange rate of 1.31. 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.

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 low commodity prices environment or further volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our AIF, our Annual MD&A and Form 40-F as at December 31, 2018).

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.