Exhibit 99.1

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

The following discussion and analysis of financial results is dated May 9, 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 months ended March 31, 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 first quarter averaged 88,583 BOE/day, a 9% decrease compared to the fourth quarter of 2018. Production decreased in North Dakota as expected, due to modest capital spending in the fourth quarter of 2018, along with the planned timing of wells coming on-stream towards the end of the quarter. Despite the lower production in the first quarter, we expect strong well performance for the remainder of the year and we are increasing our average annual production guidance to 97,000 – 101,000 BOE/day from 94,000 – 100,000 BOE/day and revising our average annual crude oil and natural gas liquids guidance to 53,500 – 56,000 bbls/day from 52,500 – 56,000 bbls/day. In addition, we expect second quarter average production of 97,500 – 100,000 BOE/day, with crude oil and natural gas liquids production of 51,500 – 53,000 bbls/day.

Capital expenditures of $160.8 million were in line with our expectations, with approximately 70% of our capital spending directed to our North Dakota crude oil properties. We are narrowing our 2019 annual capital spending guidance range to $590 – $630 million from $565 – $635 million, following the continued optimization of our operational plans in North Dakota.

Operating costs for the quarter increased to $69.8 million or $8.75/BOE from $62.9 million or $6.99/BOE in the fourth quarter of 2018 mainly due to higher well service activity in both Canada and the U.S. and lower production in the first quarter of 2019. We are maintaining our annual operating cost guidance of $8.00/BOE for 2019.

Cash G&A expenses for the quarter were $12.3 million or $1.55/BOE, compared to $12.6 million or $1.40/BOE in the fourth quarter of 2018. Cash G&A expenses remained consistent with the fourth quarter but increased on a per BOE basis, primarily due to lower production volumes during the period. We are maintaining our annual guidance of $1.50/BOE for cash G&A expenses for the year.

During the first quarter of 2019, our Bakken crude oil price differential improved to US$3.25/bbl below WTI, compared to US$5.60/bbl below WTI in the fourth quarter of 2018, as a result of stronger demand from midwest U.S. refineries and severe winter weather in North Dakota reducing Bakken supply in the field. Our Marcellus natural gas differential improved to US$0.13/Mcf above NYMEX in the first quarter, compared to US$0.34/Mcf below NYMEX in the fourth quarter of 2018, due to strong weather-related demand resulting in lower than expected storage inventory in the U.S., and the benefit of a portion of our fixed physical gas sales contracts which are tied to regional New York markets.

As of May 8, 2019, we had approximately 65% 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 have also hedged approximately 45% of our forecasted natural gas production, net of royalties, for the period April 1 to October 31, 2019.

We reported net income of $19.2 million in the first quarter of 2019 compared to $249.3 million in the fourth quarter of 2018. The decrease is primarily the result of a $95.4 million unrealized loss on commodity derivative instruments, compared to a $256.5 million unrealized gain in the fourth quarter of 2018 due to the improvement in crude oil and natural gas prices in the first quarter.

In the first quarter of 2019, cash flow from operations decreased to $109.0 million, compared to $221.6 million in the fourth quarter of 2018 due to lower crude oil production and changes to working capital. Adjusted funds flow in the quarter decreased to $168.8 million from $214.3 million in the fourth quarter of 2018, as a result of lower crude oil production and a reduced Alternative Minimum Tax (“AMT”) refund of $5.5 million in the first quarter of 2019, compared to $27.2 million in the prior period.

During the quarter, we repurchased and cancelled 1,732,038 common shares under our Normal Course Issuer Bid (“NCIB”) for total consideration of $19.8 million.

At March 31, 2019, our total debt net of cash was $363.8 million and our net debt to adjusted funds flow ratio was 0.5x.

RESULTS OF OPERATIONS

Production

Average daily production for the first quarter totaled 88,583 BOE/day, compared to production of 97,860 BOE/day in the fourth quarter of 2018. Crude oil and liquids production decreased by 8,963 bbls/day, primarily due to lower North Dakota volumes as a result of lower capital spending in the fourth quarter of 2018, along with the expected timing of wells coming on-stream in March 2019. Our natural gas production remained flat, compared to the fourth quarter of 2018.

Production in the first quarter increased by 3,503 BOE/day or 4%, when compared to production of 85,080 BOE/day for the same period of the prior year. A larger capital program in North Dakota resulted in an increase of approximately 4,500 BOE/day of liquids production. This increase was partially offset by the divestment of non-core Canadian properties in the first quarter of 2018.

Our crude oil and natural gas liquids weighting increased to 51% in the first quarter of 2019, from 49% for the same period of 2018, due to increased capital spending on our U.S. crude oil assets.

Average daily production volumes for the three months ended March 31, 2019 and 2018 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2019**	**2018**	**% Change**
Crude oil (bbls/day)	41,105	37,443	10%
Natural gas liquids (bbls/day)	4,383	4,085	7%
Natural gas (Mcf/day)	258,568	261,310	(1%)
Total daily sales (BOE/day)	88,583	85,080	4%

We are increasing our average annual production guidance to 97,000 – 101,000 BOE/day from 94,000 – 100,000 BOE/day and revising our average annual crude oil and natural gas liquids guidance to 53,500 – 56,000 bbls/day from 52,500 – 56,000 bbls/day. In addition, we expect second quarter average production of 97,500 – 100,000 BOE/day, with crude oil and natural gas liquids average production of 51,500 – 53,000 bbls/day.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, adjusted funds flow and financial condition. The following table compares quarterly average prices for the three months ended March 31, 2019 and 2018 and other periods indicated:

Pricing (average for the period)	**Q1 2019**	**Q4 2018**	**Q3 2018**	**Q2 2018**	**Q1 2018**
Benchmarks					
WTI crude oil (US$/bbl)	$ 54.90	$ 58.81	$ 69.50	$ 67.88	$ 62.87
Brent (ICE) crude oil (US$/bbl)	63.90	68.08	75.97	74.90	67.18
NYMEX natural gas – last day (US$/Mcf)	3.10	3.64	2.90	2.80	3.00
USD/CDN average exchange rate	1.33	1.32	1.31	1.29	1.26
USD/CDN period end exchange rate	1.33	1.36	1.29	1.31	1.29
Enerplus selling price(1)					
Crude oil ($/bbl)	$ 66.56	$ 64.18	$ 83.98	$ 79.98	$ 69.67
Natural gas liquids ($/bbl)	19.15	26.72	25.95	32.23	28.13
Natural gas ($/Mcf)	4.38	4.28	3.22	2.68	3.50
Average differentials					
Brent (ICE) – WTI (US$/bbl)	$ 9.00	$ 9.27	$ 6.47	$ 7.02	$ 4.31
MSW Edmonton – WTI (US$/bbl)	(4.85)	(26.30)	(6.83)	(5.45)	(5.89)
WCS Hardisty – WTI (US$/bbl)	(12.29)	(39.43)	(22.25)	(19.27)	(24.28)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.22)	(0.39)	(0.61)	(0.91)	(0.67)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.27)	(0.49)	(0.68)	(0.99)	(0.76)
Enerplus realized differentials(1)(2)					
Bakken crude oil – WTI (US$/bbl)	$ (3.25)	$ (5.60)	$ (2.54)	$ (3.42)	$ (3.27)
Marcellus natural gas – NYMEX (US$/Mcf)	0.13	(0.34)	(0.48)	(0.69)	(0.21)
Canada crude oil – WTI (US$/bbl)	(10.42)	(33.27)	(16.61)	(16.31)	(20.82)

(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 price for the first quarter of 2019 averaged $66.56/bbl, an increase of 4% compared to the previous quarter, despite a 7% decrease in WTI Benchmark pricing. This increase was due to the strengthening of crude oil differentials in the first quarter of 2019 as U.S. refinery demand returned after record levels of maintenance in the fourth quarter of 2018 combined with mandatory Alberta oil curtailments. As a result, our realized Bakken price differential improved by 42% during the quarter to average US$3.25/bbl below WTI. Our sales price continued to benefit from a portion of our physical sales that were sold on a fixed differential basis below WTI. For the remainder of 2019, we have physical sales contracts in place for an average of 19,000 bbls/day of Bakken crude oil production with fixed differentials averaging approximately US$1.90/bbl below WTI, a portion of which is sold directly into the U.S. Gulf Coast that utilizes our firm capacity on the Dakota Access Pipeline. We are maintaining our full year Bakken differential guidance of US$4.00/bbl below WTI.

Our realized price differential for our Canadian crude oil production improved by US$22.85/bbl compared to the previous quarter. Canadian crude oil prices weakened significantly during the fourth quarter as seasonal U.S. refinery maintenance and growing Canadian crude oil production placed constraints on Canadian pipeline capacity. This pressure has since been relieved mainly due to Alberta Government mandated production curtailments. We have fixed differential hedges in place for 1,500 bbl/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 $19.15/bbl during the period, which represents a 28% decrease compared to the previous quarter. The reduction is mainly due to price weakness in U.S. benchmark pricing, applicable to both propane and butane production from our U.S. Bakken assets.

NATURAL GAS

Our average realized natural gas price during the first quarter of 2019 increased by 2% compared to the fourth quarter of 2018, to average $4.38/Mcf, while NYMEX benchmark pricing decreased by 15%. The increase was mainly due to continued improvement in Marcellus pricing, where our realized differentials averaged US$0.13/Mcf above NYMEX for the period, compared to US$0.34/Mcf below NYMEX in the fourth quarter. Strong weather-related demand resulted in lower than expected storage inventory in the U.S., especially in the Northeastern region, which resulted in improved differentials. Our realized Marcellus gas price was supported by fixed physical basis sales during the quarter at markedly higher levels than the settled benchmarks. Further, basis differentials in the Marcellus continued to be supported by pipeline additions that were recently brought into service. We expect our realized Marcellus differentials for the remainder of the year to moderate from the first quarter due to the seasonality of pricing and demand in Northeastern U.S. markets and we are maintaining our full year differential guidance for the Marcellus of US$0.30/Mcf below NYMEX.

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 three months in 2019 with an average exchange rate of 1.33 US/CDN compared to 1.26 US/CDN for the same period in 2018. However, when comparing the exchange rate in the first quarter of 2019 to the fourth quarter of 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 expenditures.

As of May 8, 2019, we have hedged approximately 24,170 bbls/day of crude oil, which represents approximately 65% 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% based off our 2019 forecasted crude oil production, after royalties. Our crude oil hedges are all three-way collars, which consist of a sold put, a purchased put and a sold call. When WTI prices settle below the sold put strike price, the three-way collars 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.

As of May 8, 2019, we have hedged approximately 90,000 Mcf/day of our forecasted natural gas production for the period April 1 to October 31, 2019. This represents approximately 45% of our forecasted natural gas production, after royalties, for that period.

The following is a summary of our financial contracts in place at May 8, 2019, expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)[(1)(2)]			
	Apr 1, 2019 – Jun 30, 2019	**Jul 1, 2019 – Sep 30, 2019**	**Oct 1, 2019 – Dec 31, 2019**	**Jan 1, 2020 – Dec 31, 2020**
Three Way Collars[(2)]				
Sold Puts	$ 44.50	$ 44.64	$ 44.64	$ 46.88
%	63%	66%	66%	43%
Purchased Puts	$ 54.59	$ 54.81	$ 54.81	$ 57.50
%	63%	66%	66%	43%
Sold Calls	$ 65.52	$ 65.95	$ 65.99	$ 72.50
%	63%	66%	66%	43%

(1) Based on weighted average price (before premiums) assuming average annual production of 99,000 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 spent on our three-way collars is US$1.59/bbl from April 1, 2019 to December 31, 2020.

	NYMEX Natural Gas (US$/Mcf)[(1)]
	Apr 1, 2019 – Oct 31, 2019
Swaps	
Sold Swaps	$2.85
%	45%

(1) Based on weighted average price (before premiums) assuming average annual production of 99,000 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) ($ millions)	Three months ended March 31, 2019	2018
Cash gains/(losses):		
Crude oil	$ (2.0)	$ (6.4)
Natural gas	12.5	16.5
Total cash gains/(losses)	$ 10.5	$ 10.1
Non-cash gains/(losses):		
Crude oil	$ (86.9)	$ (29.9)
Natural gas	(8.5)	(0.7)
Total non-cash gains/(losses)	$ (95.4)	$ (30.6)
Total gains/(losses)	$ (84.9)	$ (20.5)

(Per BOE)	Three months ended March 31, 2019	2018
Total cash gains/(losses)	$ 1.32	$ 1.33
Total non-cash gains/(losses)	(11.97)	(3.99)
Total gains/(losses)	$ (10.65)	$ (2.66)

During the first quarter of 2019, we realized cash losses of $2.0 million on our crude oil contracts and cash gains of $12.5 million on our natural gas contracts. In comparison, during the first quarter of 2018, we realized cash losses of $6.4 million on our crude oil contracts and cash gains of $16.5 million on our natural gas contracts. Cash losses on our crude oil contracts were primarily due to crude oil prices rising above the swap level. Cash gains on our natural gas contracts were primarily due to natural gas prices falling below the swap level and the put strike price on our 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 the end of the first quarter of 2019, the fair value of our crude oil contracts was in a net liability position of $6.4 million and the fair value of our natural gas contracts was in a net asset position of $2.4 million. For the three months ended March 31, 2019, the change in the fair value of our crude oil contracts and natural gas contracts represented losses of $86.9 million and $8.5 million, respectively.

Revenues

($ millions)	Three months ended March 31, 2019	2018
Oil and natural gas sales	$ 356.4	$ 328.5
Royalties	(68.9)	(63.5)
Oil and natural gas sales, net of royalties	$ 287.5	$ 265.0

Oil and natural gas sales, net of royalties, for the three months ended March 31, 2019 were $287.5 million, an increase of 8% from the same period in 2018. The increase in revenue was a result of higher liquids production and higher natural gas realized prices.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended March 31, 2019	2018
Royalties	$ 68.9	$ 63.5
Per BOE	$ 8.65	$ 8.30
Production taxes	$ 14.6	$ 16.1
Per BOE	$ 1.83	$ 2.11
Royalties and production taxes	$ 83.5	$ 79.6
Per BOE	$ 10.48	$ 10.41
Royalties and production taxes (% of oil and natural gas sales)	23%	24%

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 months ended March 31, 2019, royalties and production taxes increased to $83.5 million from $79.6 million for the same period in 2018, primarily due to higher U.S. crude oil and natural gas sales.

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

Operating Expenses

	Three months ended March 31,	
($ millions, except per BOE amounts)	2019	2018
Cash operating expenses	$ 69.8	$ 53.8
Per BOE	$ 8.75	$ 7.02

For the three months ended March 31, 2019, operating expenses were $69.8 million or $8.75/BOE, compared to our annual guidance of $8.00/BOE, representing an increase of $16.0 million from the same period in 2018. The increase is mainly attributable to our higher crude oil production as our liquids weighting increased to 51% from 49% in the prior year, higher well service activity on our crude oil properties and the effects of a weaker Canadian dollar in 2019.

With production growing for the remainder of the year, we are maintaining our annual operating cost guidance of $8.00/BOE.

Transportation Costs

	Three months ended March 31,	
($ millions, except per BOE amounts)	2019	2018
Transportation costs	$ 31.3	$ 26.9
Per BOE	$ 3.92	$ 3.52

For the three months ended March 31, 2019, transportation costs were $31.3 million or $3.92/BOE, compared to our annual guidance of $4.00/BOE. During the same period in 2018, transportation costs were $26.9 million or $3.52/BOE. The increase is due to the increase in our U.S. crude oil production and a weaker Canadian dollar when compared to the prior period.

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 March 31, 2019		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	48,909 BOE/day	238,044 Mcfe/day	88,583 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 59.51	$ 4.41	$ 44.70
Royalties and production taxes	(14.92)	(0.83)	(10.48)
Cash operating expenses	(13.96)	(0.39)	(8.75)
Transportation costs	(2.75)	(0.90)	(3.92)
Netback before hedging	$ 27.88	$ 2.29	$ 21.55
Cash hedging gains/(losses)	(0.45)	0.59	1.32
Netback after hedging	$ 27.43	$ 2.88	$ 22.87
Netback before hedging ($ millions)	$ 122.7	$ 49.1	$ 171.8
Netback after hedging ($ millions)	$ 120.8	$ 61.5	$ 182.3

Netbacks by Property Type	Three months ended March 31, 2018 Crude Oil	Natural Gas	Total
Average Daily Production	44,050 BOE/day	246,180 Mcfe/day	85,080 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 62.99	$ 3.56	$ 42.91
Royalties and production taxes	(16.47)	(0.65)	(10.41)
Cash operating expenses	(10.79)	(0.50)	(7.02)
Transportation costs	(2.07)	(0.84)	(3.52)
Netback before hedging	$ 33.66	$ 1.57	$ 21.96
Cash hedging gains/(losses)	(1.61)	0.75	1.33
Netback after hedging	$ 32.05	$ 2.32	$ 23.29
Netback before hedging ($ millions)	$ 133.4	$ 34.8	$ 168.2
Netback after hedging ($ millions)	$ 127.0	$ 51.3	$ 178.3

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

Crude oil netbacks before hedging for the three months ended March 31, 2019 were lower compared to the same period in 2018 primarily due to weaker realized prices and higher operating and transportation expenses. Natural gas netbacks before hedging were higher for the first quarter of 2019 compared to the same period in 2018 mainly due to higher realized prices. For the three months ended March 31, 2019, our crude oil properties accounted for 71% of our total netback before hedging, compared to 79% during the same period 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 March 31, 2019	2018
Cash:		
G&A expense	$ 12.3	$ 13.2
Share-based compensation expense	1.3	1.9
Non-Cash:		
Share-based compensation expense	8.1	9.1
Equity swap loss/(gain)	(0.1)	(1.0)
G&A expense	0.1	—
Total G&A expenses	$ 21.7	$ 23.2

(Per BOE)	Three months ended March 31, 2019	2018
Cash:		
G&A expense	$ 1.55	$ 1.72
Share-based compensation expense	0.17	0.25
Non-Cash:		
Share-based compensation expense	1.01	1.19
Equity swap loss/(gain)	(0.01)	(0.13)
G&A expense	0.01	—
Total G&A expenses	$ 2.73	$ 3.03

For the three months ended March 31, 2019, cash G&A expenses were $12.3 million or $1.55/BOE compared to $13.2 million or $1.72/BOE for the same period in 2018. Cash G&A expenses were essentially flat but decreased on a per BOE basis compared to the same period in 2018 due to higher production.

During the first quarter of 2019, we reported cash SBC expense of $1.3 million due to the grant of additional deferred share units and the increase in our share price on outstanding deferred share units. In comparison, during the same period of 2018, we recorded cash SBC expense of $1.9 million. We recorded non-cash SBC expense of $8.1 million or $1.01/BOE in the first quarter of 2019, a decrease from an expense of $9.1 million or $1.19/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 first quarter we recorded a non-cash mark-to-market gain of $0.1 million on these hedges due to the increase in our share price. We had 195,000 units outstanding, hedged at a weighted average price of $20.60 per share at March 31, 2019.

We are maintaining our annual cash G&A guidance of $1.50/BOE.

Interest Expense

For the three months ended March 31, 2019, we recorded total interest expense of $8.4 million, compared to $9.1 million for the same period in 2018. The decrease in interest expense for the three month period ended March 31, 2019 was primarily due to the repayment of a portion of our 2009 senior notes which carry a higher coupon rate, offset by the impact of a weaker Canadian dollar on our U.S. dollar denominated interest expense.

At March 31, 2019, we were undrawn on our $800 million bank credit facility and our debt balance consisted of 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

	Three months ended March 31,	
($ millions)	**2019**	**2018**
Realized:		
Foreign exchange (gain)/loss on settlements	$ (0.1)	$ 0.1
Translation of U.S. dollar cash held in Canada (gain)/loss	5.2	(7.3)
Unrealized (gain)/loss	(17.1)	17.6
Total foreign exchange (gain)/loss	$ (12.0)	$ 10.4
USD/CDN average exchange rate	1.33	1.26
USD/CDN period end exchange rate	1.33	1.29

For the three months ended March 31, 2019, we recorded a foreign exchange gain of $12.0 million compared to losses of $10.4 million for the same period 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 March 31, 2019 to December 31, 2018, the Canadian dollar strengthened relative to the U.S. dollar, resulting in an unrealized gain of $17.1 million. See Note 13 to the Interim Financial Statements for further details.

Capital Investment

	Three months ended March 31,	
($ millions)	**2019**	**2018**
Capital spending(1)	$ 160.8	$ 151.5
Office capital(1)	1.1	1.4
Line fill	5.1	—
Sub-total	167.0	152.9
Property and land acquisitions	$ 3.0	$ 12.3
Property divestments	(0.5)	(7.0)
Sub-total	2.5	5.3
Total	$ 169.5	$ 158.2

(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 months ended March 31, 2019 totaled $160.8 million compared to $151.5 million for the same period in 2018. The increase in spending is in line with our strategy to deliver production and liquids growth through 2019. During the first quarter of 2019, we spent $128.1 million on our U.S. crude oil properties, $15.2 million on our Marcellus natural gas assets and $14.7 million on our Canadian waterflood properties. For the three months ended March 31, 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 first quarter, we completed $3.0 million in property and land acquisitions compared to $12.3 million for the same period in 2018 which included minor acquisitions of leases and undeveloped land. Property divestments for the three months ended March 31, 2019 were $0.5 million compared to $7.0 million for the same period in 2018 which primarily related to an acreage swap in North Dakota and the divestment of non-core properties in Northwestern Alberta.

We are narrowing our 2019 annual capital spending guidance range to $590 million – $630 million, following the continued optimization of our operational plans in North Dakota.

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

($ millions, except per BOE amounts)	Three months ended March 31, 2019	2018
DD&A expense	$ 75.9	$ 64.0
Per BOE	$ 9.52	$ 8.36

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2019, DD&A increased compared to the same period 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 5.56%, to be $127.9 million at March 31, 2019, compared to 5.59% and $126.1 million at December 31, 2018. For the three months ended March 31, 2019, asset retirement obligation settlements were $5.4 million compared to $3.3 million during the same period 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 March 31, 2019, our total lease liability was $65.0 million. In addition, ROU assets of $64.9 million were recorded, which equals lease liabilities less non-cash lease incentives. See Note 3(a) and Note 10 to the Interim Financial Statements for further details.

Income Taxes

($ millions)	Three months ended March 31, 2019	2018
Current tax expense/(recovery)	$ (5.5)	$ 0.1
Deferred tax expenses/(recovery)	(17.9)	12.4
Total tax expense/(recovery)	$ (23.4)	$ 12.5

We recorded a total tax recovery of $23.4 million during the first quarter of 2019, compared to a $12.5 million expense for the same period in 2018. The recovery in 2019 primarily relates to lower net income, as a result of higher unrealized commodity derivative losses, compared to the same period in 2018. The current tax recovery of $5.5 million in 2019 primarily relates to the reversal of the reserve recorded at December 31, 2017 for the sequestered portion of our U.S. AMT refund as the U.S. federal government announced in the first quarter of 2019 that they do not intend to sequester any portion of the AMT refund. 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 March 31, 2019, our senior debt to adjusted EBITDA ratio was 0.9x 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 March 31, 2019 was $363.8 million, an increase of 9% compared to $333.5 million at December 31, 2018. Total debt was comprised of $682.8 million of senior notes less $319.0 million in cash. At March 31, 2019, we were undrawn on our $800 million bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 103% for the three months ended March 31, 2019, consistent with the same period in 2018.

For the three months ended March 31, 2019, the Company repurchased and cancelled approximately 1.7 million shares under our previous and current NCIB for a total cost of $19.8 million.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, increased to $161.6 million at March 31, 2019 from $143.1 million at December 31, 2018. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, adjusted funds flow and our bank credit facility. We have sufficient liquidity to meet our financial commitments, as disclosed under “Commitments” in the Annual MD&A.

At March 31, 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.

The following table lists our financial covenants as at March 31, 2019:

Covenant Description		March 31, 2019
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	0.9x
Total debt to adjusted EBITDA (1)	4.0x	0.9x
Total debt to capitalization	50%	19%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	0.9x
Senior debt to consolidated present value of total proved reserves(3)	60%	20%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	21.5x

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 March 31, 2019 was $166.4 million and $777.6 million, respectively.
“Total debt” is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.
“Capitalization” is calculated as the sum of total debt and shareholder’s equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

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

Dividends

	Three months ended March 31,	
($ millions, except per share amounts)	2019	2018
Dividends to shareholders(1)	$ 7.2	$ 7.3
Per weighted average share (Basic)	$ 0.03	$ 0.03

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

During the three months ended March 31, 2019, we reported total dividends of $7.2 million or $0.03 per share compared to $7.3 million or $0.03 per share for the same period 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

	Three months ended March 31,	
	2019	2018
Share capital ($ millions)	$ 3,317.9	$ 3,411.9
Common shares outstanding (thousands)	238,243	244,773
Weighted average shares outstanding – basic (thousands)	238,922	243,874
Weighted average shares outstanding – diluted (thousands)	241,298	249,191

For the three months ended March 31, 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 three months ended March 31, 2019, no shares were issued pursuant to our stock option plan, resulting in no additional share capital (2018 – 104,622; $0.1 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. Subject to exceptions for block purchases, the Company will limit daily purchases of common shares on the TSX in connection with the NCIB to no more than 25% (270,933 common shares) of the average daily trading volume of the common shares on the TSX (1,083,735 common shares) during any trading day. Purchases under the NCIB will be made through open market purchases at market price, as well as by other means as may be permitted by applicable securities regulatory authorities, including private agreements. Common shares purchased under the NCIB will be cancelled. Shareholders may obtain a copy of the Company's notice to the TSX to renew its NCIB, without charge, by contacting the Corporate Secretary of the Company at Suite 3000, 333 - 7th Avenue S.W., Calgary, Alberta, T2P 2Z1, telephone (403) 298-2200.

During the three months ended March 31, 2019, the Company repurchased 1,732,038 common shares under the previous and current NCIB at an average price of $11.43 per share, for total consideration of $19.8 million. Of the amount paid, $24.1 million was charged to share capital and $4.3 million was credited to accumulated deficit. Subsequent to the quarter and up to May 8, 2019, the Company repurchased 1,259,832 common shares under the NCIB at an average price of $11.86 per share, for total consideration of $15.0 million.

At May 8, 2019, we had 236,983,232 common shares outstanding. In addition, an aggregate of 8,572,694 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

	Three months ended March 31, 2019			Three months ended March 31, 2018		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	8,998	32,107	41,105	9,513	27,930	37,443
Natural gas liquids (bbls/day)	984	3,399	4,383	1,247	2,838	4,085
Natural gas (Mcf/day)	24,348	234,220	258,568	33,132	228,178	261,310
Total average daily production (BOE/day)	14,040	74,543	88,583	16,282	68,798	85,080
Pricing(2)						
Crude oil (per bbl)	$ 59.07	$ 68.66	$ 66.56	$ 52.82	$ 75.41	$ 69.67
Natural gas liquids (per bbl)	35.89	14.30	19.15	45.11	20.66	28.13
Natural gas (per Mcf)	4.64	4.35	4.38	3.12	3.56	3.50
Capital Expenditures						
Capital spending	$ 17.5	$ 143.3	$ 160.8	$ 13.2	$ 138.3	$ 151.5
Acquisitions	1.0	2.0	3.0	1.1	11.2	12.3
Divestments	(0.1)	(0.4)	(0.5)	(0.9)	(6.1)	(7.0)
Netback(3) **Before Hedging**						
Oil and natural gas sales	$ 61.8	$ 294.6	$ 356.4	$ 60.7	$ 267.8	$ 328.5
Royalties	(8.9)	(60.0)	(68.9)	(9.9)	(53.6)	(63.5)
Production taxes	(0.6)	(14.0)	(14.6)	(0.8)	(15.3)	(16.1)
Cash operating expenses	(21.0)	(48.8)	(69.8)	(20.6)	(33.2)	(53.8)
Transportation costs	(2.7)	(28.6)	(31.3)	(3.0)	(23.9)	(26.9)
Netback before hedging	$ 28.6	$ 143.2	$ 171.8	$ 26.4	$ 141.8	$ 168.2
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 84.9	$ —	$ 84.9	$ 20.5	$ —	$ 20.5
General and administrative expense(4)	13.2	8.5	21.7	15.4	7.8	23.2
Current income tax expense/(recovery)	—	(5.5)	(5.5)	—	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				
First Quarter	$ 287.5	$ 19.2	$ 0.08	$ 0.08
Total 2019	$ 287.5	$ 19.2	$ 0.08	$ 0.08
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, decreased in the first quarter of 2019 compared to the fourth quarter of 2018 due to lower production volumes. Net income decreased in the first quarter of 2019 due to unrealized losses on commodity derivative instruments, compared to a significant unrealized gain during the fourth quarter of 2018.

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.

2019 UPDATED GUIDANCE

We are increasing our annual average production guidance to 97,000 – 101,000 BOE/day and revising our average annual crude oil and natural gas liquids guidance to 53,500 – 56,000 bbls/day. In addition, we expect second quarter average production of 97,500 – 100,000 BOE/day, with average crude oil and natural gas liquids production of 51,500 – 53,000 bbls/day.

We are narrowing our 2019 capital spending guidance to $590 – $630 million from our previous range of $565 – $635 million.

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

Summary of 2019 Expectations	Target
Capital spending	$590 - $630 million (from $565 - $635 million)
Average annual production	97,000 - 101,000 BOE/day (from 94,000 - 100,000 BOE/day)
Average annual crude oil and natural gas liquids production	53,500 - 56,000 bbls/day (from 52,500 - 56,000 bbls/day)
Second quarter average production	97,500 - 100,000 BOE/day
Second quarter average crude oil and natural gas liquids production	51,500 - 53,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	25%
Operating expenses	$8.00/BOE
Transportation costs	$4.00/BOE
Cash G&A expenses	$1.50/BOE

2019 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(4.00)/bbl
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(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 March 31,**	
($ millions)	**2019**	**2018**
Oil and natural gas sales	$ 356.4	$ 328.5
Less:		
Royalties	(68.9)	(63.5)
Production taxes	(14.6)	(16.1)
Cash operating expenses	(69.8)	(53.8)
Transportation costs	(31.3)	(26.9)
Netback before hedging	$ 171.8	$ 168.2
Cash gains/(losses) on derivative instruments	10.5	10.1
Netback after hedging	$ 182.3	$ 178.3

"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 net cash 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 March 31,**	
($ millions)	**2019**	**2018**
Cash flow from operating activities	$ 109.0	$ 159.3
Asset retirement obligation expenditures	5.4	3.3
Changes in non-cash operating working capital	54.4	(7.4)
Adjusted funds flow	$ 168.8	$ 155.2

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

Calculation of Free Cash Flow	**Three months ended March 31,**	
($ millions)	**2019**	**2018**
Adjusted funds flow	$ 168.8	$ 155.2
Capital spending	(160.8)	(151.5)
Free cash flow	$ 8.0	$ 3.7

"Adjusted net income" is used by Enerplus and is useful to investors and securities analyst 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 and the tax effect of these items.

Calculation of Adjusted Net Income	**Three months ended March 31,**	
($ millions)	**2019**	**2018**
Net income/(loss)	$ 19.2	$ 29.6
Unrealized derivative instrument (gain)/loss	95.3	29.6
Unrealized foreign exchange (gain)/loss	(17.1)	17.6
Tax effect on above items	(24.9)	(8.4)
Adjusted net income	$ 72.5	$ 68.4

"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 March 31,**	
($ millions)	**2019**	**2018**
Dividends	$ 7.2	$ 7.3
Capital, office expenditures and line fill	167.0	152.9
Sub-total	$ 174.2	$ 160.2
Adjusted funds flow	$ 168.8	$ 155.2
Adjusted payout ratio (%)	103%	103%

"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)	**March 31, 2019**
Net income/(loss)	$ 367.8
Add:	
Interest	36.1
Current and deferred tax expense/(recovery)	67.3
DD&A and asset impairment	316.1
Other non-cash charges[(2)]	(9.7)
Adjusted EBITDA	$ 777.6

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at March 31, 2019 include the three months ended March 31, 2019 and the second, 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 March 31, 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 January 1, 2019 and ended March 31, 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, including second quarter, 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 current NCIB and share repurchases thereunder; 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$60.00/bbl, a NYMEX price of US$2.75/Mcf, and a USD/CDN exchange rate of 1.33. 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.