Exhibit 99.1

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

The following discussion and analysis of financial results is dated November 8, 2018 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 nine months ended September 30, 2018 and 2017 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2017 and 2016 and for the years ended December 31, 2017, 2016 and 2015; and
- our MD&A for the year ended December 31, 2017 (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. 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 unless otherwise stated. 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 2018, Enerplus adopted ASC 606 - *Revenue from contracts with customers*. The adoption of this standard had no impact on the Interim Financial Statements, with the exception of additional note disclosures. See Notes 3(a) and 10 to the Interim Financial Statements for further details.

OVERVIEW

Production for the third quarter averaged 96,861 BOE/day, a 4% increase compared to the second quarter of 2018. Our crude oil and natural gas liquids production increased by 7% to 53,430 bbls/day from 50,050 bbls/day in the second quarter of 2018. The increase in production is primarily due to strong well performance in North Dakota with 18.1 net wells coming on-stream during the third quarter as well as 3.2 net wells coming on-stream in Colorado. As a result, we are revising our average annual production guidance range to 92,500 – 93,000 BOE/day, the high end of our previous range of 91,000 – 93,000 BOE/day. We are also revising our average annual crude oil and liquids guidance range to 49,500 – 50,000 bbls/day, the high end of our previous range of 49,000 – 50,000 bbls/day and guiding to a fourth quarter average crude oil and liquids production range of 53,500 – 54,500 bbls/day.

Capital expenditures totaled $193.3 million for the third quarter and $521.8 million year to date, in line with our expectations. Approximately 75% of our capital spending year to date has been directed to our North Dakota crude oil properties. We are maintaining our annual capital spending guidance of $585 million. Capital activity for the remainder of the year will be largely focused on drilling in North Dakota in preparation for the 2019 program.

Operating costs for the quarter decreased to $6.81/BOE from $7.20/BOE in the second quarter, primarily due to our North Dakota operations where we saw reduced well service activity and lower gas handling costs in the third quarter. We are maintaining our annual operating cost guidance of $7.00/BOE.

Cash G&A expenses for the third quarter were $1.35/BOE, a decrease of 6% from $1.44/BOE in the second quarter of 2018. Cash G&A expenses per BOE decreased from the second quarter with higher production during the period. We are lowering our annual guidance target for cash G&A expenses to $1.50/BOE from $1.55/BOE.

As of October 30, 2018, we had approximately 68% of our forecasted crude oil production, net of royalties, hedged for the remainder of 2018, and approximately 68% and 47% of our crude oil production, net of royalties, hedged in 2019 and 2020, respectively, based on 2018 forecasted net production. We have also hedged approximately 17% of our forecasted natural gas production, net of royalties, for the remainder of 2018. In addition, we have physical sales contracts in place in the Bakken for 20,250 bbls/day of production at an average differential of US$2.53/bbl below WTI for the fourth quarter of 2018, and on 16,000 bbls/day of production in 2019 averaging approximately US$3.00/bbl below WTI.

We recorded net income of $86.9 million and adjusted funds flow of $210.4 million in the third quarter of 2018, compared to $12.4 million and $173.7 million, respectively, in the second quarter of 2018. Net income in the third quarter increased with higher realized commodity prices and production, as well as lower non-cash mark-to-market losses recorded on our commodity derivative instruments.

During the quarter, we repurchased and cancelled 544,300 common shares under our Normal Course Issuer Bid (“NCIB”).

At September 30, 2018, our total debt net of cash was $313.6 million and our net debt to adjusted funds flow ratio was 0.4x.

RESULTS OF OPERATIONS

Production

Average daily production for the third quarter totaled 96,861 BOE/day, an increase of 3,978 BOE/day or 4% compared to the second quarter of 2018. Crude oil and natural gas liquids production increased by 7%, primarily due to our successful capital program focused on our U.S. crude oil properties. Natural gas production also increased in the period with less downtime and pipeline maintenance in the Marcellus when compared to the second quarter.

For the three and nine months ended September 30, 2018, crude oil and liquids production increased by 14,504 bbls/day or 37% and 9,618 bbls/day or 25%, respectively, compared to the same periods in 2017. Production increased primarily due to higher spending in North Dakota where 34.3 net wells have been brought on-stream year to date. Natural gas production increased by 8% for the three months ended September 30, 2018 compared to the same period in 2017 with increased activity in the Marcellus as a result of stronger realized prices and additional pipeline capacity coming on-stream in the basin. For the nine-month period ending September 30, 2018, natural gas production decreased by 3% due to non-core Canadian asset divestments in 2017.

Our crude oil and natural gas liquids weighting increased to 55% in the third quarter of 2018, from 49% for the same period of 2017, as a result of growth from our North Dakota crude oil assets in 2018 and the divestment of non-core Canadian natural gas weighted properties in 2017.

Average daily production volumes for the three and nine months ended September 30, 2018 and 2017 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2018**	**2017**	**% Change**	**2018**	**2017**	**% Change**
Crude oil (bbls/day)	48,867	35,245	39%	43,892	35,102	25%
Natural gas liquids (bbls/day)	4,563	3,681	24%	4,487	3,659	23%
Natural gas (Mcf/day)	260,591	241,212	8%	259,629	267,852	(3%)
Total daily sales (BOE/day)	96,861	79,128	22%	91,651	83,403	10%

We are revising our average annual production guidance range to 92,500 – 93,000 BOE/day, the high end of our previous range of 91,000 – 93,000 BOE/day. We are also revising our average annual crude oil and liquids guidance range to 49,500 – 50,000 bbls/day, the high end of our previous range of 49,000 – 50,000 bbls/day, and guiding to a fourth quarter average crude oil and liquids production range of 53,500 – 54,500 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 nine months ended September 30, 2018 and 2017 and other periods indicated:

	Nine months ended September 30,						
Pricing (average for the period)	**2018**	**2017**	**Q3 2018**	**Q2 2018**	**Q1 2018**	**Q4 2017**	**Q3 2017**
Benchmarks							
WTI crude oil (US$/bbl)	$ 66.75	$ 49.47	$ 69.50	$ 67.88	$ 62.87	$ 55.40	$ 48.20
Brent (ICE) crude oil (US$/bbl)	72.68	52.59	75.97	74.90	67.18	61.54	52.18
NYMEX natural gas – last day (US$/Mcf)	2.90	3.17	2.90	2.80	3.00	2.93	3.00
AECO natural gas – monthly index ($/Mcf)	1.41	2.58	1.35	1.02	1.85	1.96	2.04
USD/CDN average exchange rate	1.29	1.31	1.31	1.29	1.26	1.27	1.25
USD/CDN period end exchange rate	1.29	1.25	1.29	1.31	1.29	1.26	1.25
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 78.58	$ 55.75	$ 83.98	$ 79.98	$ 69.67	$ 65.91	$ 54.21
Natural gas liquids ($/bbl)	28.85	29.09	25.95	32.23	28.13	32.26	26.22
Natural gas ($/Mcf)	3.14	3.26	3.22	2.68	3.50	3.03	2.58
Average differentials							
Brent (ICE) – WTI (US$/bbl)	$ 5.93	$ 3.12	$ 6.47	$ 7.02	$ 4.31	$ 6.14	$ 3.98
MSW Edmonton – WTI (US$/bbl)	(6.06)	(2.90)	(6.83)	(5.45)	(5.89)	(1.14)	(2.89)
WCS Hardisty – WTI (US$/bbl)	(21.93)	(11.88)	(22.25)	(19.27)	(24.28)	(12.27)	(9.94)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.73)	(0.84)	(0.61)	(0.91)	(0.67)	(1.32)	(1.29)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.81)	(0.91)	(0.68)	(0.99)	(0.76)	(1.40)	(1.36)
AECO monthly – NYMEX (US$/Mcf)	(1.80)	(1.21)	(1.87)	(2.00)	(1.44)	(1.40)	(1.39)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI (US$/bbl)	$ (3.03)	$ (4.69)	$ (2.54)	$ (3.42)	$ (3.27)	$ (1.61)	$ (3.24)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.46)	(0.75)	(0.48)	(0.69)	(0.21)	(0.81)	(1.02)
Canada crude oil – WTI (US$/bbl)	(17.86)	(11.09)	(16.61)	(16.31)	(20.82)	(10.47)	(9.29)
Canada natural gas – NYMEX (US$/Mcf)	(0.82)	(0.63)	(0.77)	(1.18)	(0.52)	(0.56)	(1.00)

(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 during the third quarter of 2018 increased by 5%, compared to the second quarter of 2018, averaging $83.98/bbl. Crude oil prices were volatile during the third quarter, however, benchmark WTI crude oil prices increased by 2%. The volatility was largely related to concerns over trade conflict and supply uncertainty, due to ongoing geopolitical issues and growth in U.S. production. Continued strength in Bakken differentials offset lower prices realized for our Canadian crude oil production during the quarter.

Our realized Bakken price differential improved by 26% during the quarter to average US$2.54/bbl below WTI and averaged US$3.03/bbl below WTI year to date. Subsequent to the quarter, a significant amount of Midwest U.S. refining capacity was taken off-line for scheduled seasonal maintenance. This resulted in weaker Bakken prices contracted for November and December versus previous months. We have physical sales contracts in place for approximately 20,250 bbls/day of Bakken crude oil production at an average differential of US$2.53/bbl below WTI for the fourth quarter that is expected to provide some protection from this short-term seasonal weakness in pricing. As a result of the weaker differentials in the fourth quarter, we are revising our full year Bakken differential guidance to average approximately US$3.80/bbl below WTI. For 2019, we have physical sales contracts in place for approximately 16,000 bbls/day of Bakken crude oil production with fixed differentials averaging approximately US$3.00/bbl below WTI.

Our realized price differential for our Canadian crude oil production widened by US$0.30/bbl compared to the second quarter of 2018. Canadian crude oil prices weakened significantly late in the third quarter as seasonal U.S. refinery maintenance and growing Canadian crude oil production placed constraints on Canadian pipeline capacity and increased demand for rail to transport production out of the region. We have fixed differential hedges in place for 3,000 bbl/day of our Canadian heavy crude oil production at an average differential of US$14.46/bbl below WTI for the remainder of 2018, which is expected to continue to provide some protection against this price weakness.

Our realized price for natural gas liquids averaged $25.95/bbl during the period, which represents a 19% decrease compared to the previous quarter, due to lower condensate prices in both the U.S. and Canada.

NATURAL GAS

Our average realized natural gas price during the third quarter of 2018 increased by 20% compared to the second quarter of 2018, to average $3.22/Mcf. The increase was mainly due to continued improvement in Marcellus in basin prices. Our realized Marcellus sales differential, excluding transportation and gathering costs, averaged US$0.48/Mcf below NYMEX for the period. Strong demand for seasonal power generation resulted in lower than expected storage balances in the U.S., especially in the Northeastern region, which resulted in improved differentials. Further, basis differentials in the Marcellus continued to improve subsequent to the quarter as two new pipeline projects representing 2.7 Bcf/day of additional pipeline capacity were brought into service in early October. We are maintaining our full year differential guidance for the Marcellus of US$0.40/Mcf below NYMEX.

Benchmark AECO gas prices continue to remain weak during the third quarter of 2018 due to transportation constraints out of the basin. Our realized Canadian natural gas price differential averaged US$0.77/Mcf below NYMEX. We continue to benefit from our AECO/NYMEX physical sales contracts, which have an average fixed basis differential of US$0.63/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 stronger Canadian dollar decreases 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 stronger during the first nine months with an average exchange rate of 1.29 USD/CDN compared to 1.31 USD/CDN for the same period in 2017. However, when comparing the exchange rate in the third quarter of 2018 to the second quarter, the Canadian dollar weakened relative to the U.S. dollar. This was due to concerns related to the impact of the ongoing North American Free Trade Agreement (“NAFTA”) negotiations, other U.S. policies related to trade, as well as interest rates in Canada and the U.S. that influenced the foreign exchange rate.

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 October 30, 2018, we have hedged approximately 23,000 bbls/day of our expected crude oil production for the remainder of 2018, which represents approximately 68% of our forecasted crude oil production, after royalties. For 2019, we are hedged on 23,140 bbls/day, which represents approximately 68% of our 2018 forecasted crude oil production, after royalties. For 2020, we have hedged 16,000 bbls/day, which represents 47% of our 2018 forecasted crude oil production, after royalties. Our crude oil hedges are predominantly 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 funds flow.

As of October 30, 2018, we have hedged approximately 33,370 Mcf/day of our forecasted natural gas production for the remainder of 2018. This represents approximately 17% of our forecasted natural gas production, after royalties.

The following is a summary of our financial contracts in place at October 30, 2018, expressed as a percentage of our forecasted 2018 net production volumes:

	WTI Crude Oil (US$/bbl)(1)(2)			
	Oct 1, 2018 – Dec 31, 2018	**Jan 1, 2019 – Mar 31, 2019**	**Apr 1, 2019 – Dec 31, 2019**	**Jan 1, 2020 – Dec 31, 2020**
Swaps				
Sold Swaps	$ 53.73	$ 53.73	—	—
%	9%	9%	—	—
Three Way Collars(2)				
Sold Puts	$ 42.74	$ 44.28	$ 44.60	$ 46.88
%	59%	50%	71%	47%
Purchased Puts	$ 52.48	$ 54.12	$ 54.74	$ 57.50
%	59%	50%	71%	47%
Sold Calls	$ 61.10	$ 64.12	$ 65.82	$ 72.50
%	59%	50%	71%	47%

(1) Based on weighted average price (before premiums) assuming average annual production of 92,750 BOE/day, which is the mid-point of our updated annual 2018 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$1.60/bbl from October 1, 2018 to December 31, 2020.

	NYMEX Natural Gas (US$/Mcf)[1]
	Oct 1, 2018 – Dec 31, 2018
Collars	
Purchased Puts	$ 2.75
%	17%
Sold Calls	$ 3.43
%	17%

(1) Based on weighted average price (before premiums) assuming average annual production of 92,750 BOE/day, which is the mid-point of our updated annual 2018 guidance, less royalties and production taxes of 25%. A portion of the sold puts are settled annually rather than monthly.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2018	2017	2018	2017
Cash gains/(losses):				
Crude oil	$ (24.3)	$ 2.9	$ (50.7)	$ 4.2
Natural gas	0.4	—	17.7	7.5
Total cash gains/(losses)	$ (23.9)	$ 2.9	$ (33.0)	$ 11.7
Non-cash gains/(losses):				
Crude oil	$ (30.0)	$ (37.4)	$ (130.8)	$ 34.2
Natural gas	(0.2)	0.3	(1.7)	9.4
Total non-cash gains/(losses)	$ (30.2)	$ (37.1)	$ (132.5)	$ 43.6
Total gains/(losses)	$ (54.1)	$ (34.2)	$ (165.5)	$ 55.3

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2018	2017	2018	2017
Total cash gains/(losses)	$ (2.68)	$ 0.40	$ (1.32)	$ 0.51
Total non-cash gains/(losses)	(3.39)	(5.10)	(5.29)	1.91
Total gains/(losses)	$ (6.07)	$ (4.70)	$ (6.61)	$ 2.42

During the third quarter of 2018, we realized cash losses of $24.3 million on our crude oil contracts and cash gains of $0.4 million on our natural gas contracts. In comparison, during the third quarter of 2017, we realized cash gains of $2.9 million on our crude oil contracts. Cash losses on our crude oil contracts were primarily due to crude oil prices rising above the swap level and the sold call strike price on our three way collar hedge positions.

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 third quarter of 2018, the fair value of our crude oil contracts was in a net liability position of $165.0 million, and the fair value of our natural gas contracts was nil. For the three and nine months ended September 30, 2018, the change in the fair value of our crude oil contracts represented losses of $30.0 million and $130.8 million, respectively, and our natural gas contracts represented losses of $0.2 million and $1.7 million, respectively.

Revenues

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2018	2017	2018	2017
Oil and natural gas sales	$ 466.4	$ 241.9	$ 1,201.8	$ 801.7
Royalties	(92.8)	(45.8)	(235.8)	(152.1)
Oil and natural gas sales, net of royalties	$ 373.6	$ 196.1	$ 966.0	$ 649.6

Oil and natural gas sales, net of royalties for the three and nine months ended September 30, 2018, were $373.6 million and $966.0 million, respectively, an increase of 91% and 49% from the same periods in 2017. The increase in revenue was a result of the improvement in crude oil and natural gas prices in the period, along with higher production when compared to the prior year.

Royalties and Production Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2018	2017	2018	2017
Royalties	$ 92.8	$ 45.8	$ 235.8	$ 152.1
Per BOE	$ 10.41	$ 6.29	$ 9.42	$ 6.68
Production taxes	$ 26.6	$ 12.3	$ 65.4	$ 36.5
Per BOE	$ 2.98	$ 1.69	$ 2.61	$ 1.60
Royalties and production taxes	$ 119.4	$ 58.1	$ 301.2	$ 188.6
Per BOE	$ 13.39	$ 7.98	$ 12.03	$ 8.28
Royalties and production taxes (% of oil and natural gas sales)	26%	24%	25%	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 and nine months ended September 30, 2018, royalties and production taxes increased to $119.4 million and $301.2 million, respectively, from $58.1 million and $188.6 million for the same periods in 2017 primarily due to higher U.S. crude oil sales.

We are maintaining our annual average royalty and production tax rate guidance of 25% for 2018.

Operating Expenses

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2018	2017	2018	2017
Cash operating expenses	$ 60.6	$ 48.9	$ 175.3	$ 145.4
Non-cash (gains)/losses[(1)]	0.1	(0.1)	—	(0.4)
Total operating expenses	$ 60.7	$ 48.8	$ 175.3	$ 145.0
Per BOE	$ 6.81	$ 6.71	$ 7.01	$ 6.37

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

For the three and nine months ended September 30, 2018, operating expenses were $60.7 million ($6.81/BOE) and $175.3 million ($7.01/BOE) respectively, compared to our annual guidance of $7.00/BOE. Operating costs increased from $48.8 million ($6.71/BOE) and $145.0 million ($6.37/BOE), respectively, when compared to the same periods in 2017. The increases were due to a higher weighting of crude oil and liquids production, as well as higher repairs and maintenance and water handling rates.

We are maintaining our annual operating cost guidance of $7.00/BOE.

Transportation Costs

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2018	2017	2018	2017
Transportation costs	$ 33.0	$ 26.3	$ 90.1	$ 85.1
Per BOE	$ 3.70	$ 3.61	$ 3.60	$ 3.74

For the three and nine months ended September 30, 2018, transportation costs were $33.0 million ($3.70/BOE) and $90.1 million ($3.60/BOE) respectively, compared to our annual guidance of $3.60/BOE. During the same periods in 2017, transportation costs were $26.3 million ($3.61/BOE) and $85.1 million ($3.74/BOE), respectively. The increase in costs on a per BOE basis for the three months ended September 30, 2018 was due to a weakening Canadian dollar when compared to the prior period. The decrease in costs on a per BOE basis for the nine months ended September 30, 2018 resulted from increased North Dakota natural gas and natural gas liquids production in the U.S. with minimal associated transportation costs.

We are maintaining our annual guidance for transportation costs of $3.60/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.

Netbacks by Property Type	Three months ended September 30, 2018 Crude Oil	Natural Gas	Total
Average Daily Production	57,244 BOE/day	237,702 Mcfe/day	96,861 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 75.33	$ 3.19	$ 52.32
Royalties and production taxes	(20.16)	(0.60)	(13.39)
Cash operating expenses	(10.05)	(0.35)	(6.80)
Transportation costs	(2.50)	(0.91)	(3.70)
Netback before hedging	$ 42.62	$ 1.33	$ 28.43
Cash hedging gains/(losses)	(4.60)	0.02	(2.68)
Netback after hedging	$ 38.02	$ 1.35	$ 25.75
Netback before hedging ($ millions)	$ 224.5	$ 28.9	$ 253.4
Netback after hedging ($ millions)	$ 200.2	$ 29.3	$ 229.5

Netbacks by Property Type	Three months ended September 30, 2017 Crude Oil	Natural Gas	Total
Average Daily Production	42,164 BOE/day	221,784 Mcfe/day	79,128 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 49.22	$ 2.50	$ 33.23
Royalties and production taxes	(12.13)	(0.54)	(7.98)
Cash operating expenses	(10.85)	(0.34)	(6.73)
Transportation costs	(2.35)	(0.84)	(3.61)
Netback before hedging	$ 23.89	$ 0.78	$ 14.91
Cash hedging gains/(losses)	0.75	—	0.40
Netback after hedging	$ 24.64	$ 0.78	$ 15.31
Netback before hedging ($ millions)	$ 92.7	$ 15.9	$ 108.6
Netback after hedging ($ millions)	$ 95.6	$ 15.9	$ 111.5

Netbacks by Property Type	Nine months ended September 30, 2018 Crude Oil	Natural Gas	Total
Average Daily Production	51,623 BOE/day	240,168 Mcfe/day	91,651 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 70.67	$ 3.14	$ 48.03
Royalties and production taxes	(18.63)	(0.59)	(12.03)
Cash operating expenses	(10.65)	(0.39)	(7.01)
Transportation costs	(2.35)	(0.87)	(3.60)
Netback before hedging	$ 39.04	$ 1.29	$ 25.39
Cash hedging gains/(losses)	(3.60)	0.27	(1.32)
Netback after hedging	$ 35.44	$ 1.56	$ 24.07
Netback before hedging ($ millions)	$ 550.1	$ 85.1	$ 635.2
Netback after hedging ($ millions)	$ 499.4	$ 102.8	$ 602.2

Netbacks by Property Type	Nine months ended September 30, 2017 Crude Oil	Natural Gas	Total
Average Daily Production	42,420 BOE/day	245,900 Mcfe/day	83,403 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 50.54	$ 3.22	$ 35.21
Royalties and production taxes	(12.87)	(0.59)	(8.28)
Cash operating expenses	(10.38)	(0.38)	(6.39)
Transportation costs	(2.40)	(0.85)	(3.74)
Netback before hedging	$ 24.89	$ 1.40	$ 16.80
Cash hedging gains/(losses)	0.36	0.11	0.51
Netback after hedging	$ 25.25	$ 1.51	$ 17.31
Netback before hedging ($ millions)	$ 288.3	$ 94.3	$ 382.6
Netback after hedging ($ millions)	$ 292.4	$ 101.9	$ 394.3

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

Crude oil netbacks before hedging for the three and nine months ended September 30, 2018 were higher compared to the same periods in 2017 primarily due to higher production and improved realized prices. For the three and nine months ended September 30, 2018, our crude oil properties accounted for 89% and 87% of our netback before hedging, respectively, compared to 85% and 75% for the three and nine-month periods ended in 2017.

General and Administrative ("G&A") Expenses

Total G&A expenses include cash G&A expenses and share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans"). See Note 11 and Note 14 to the Interim Financial Statements for further details.

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2018	2017	2018	2017
Cash:				
G&A expense	$ 12.0	$ 11.7	$ 37.3	$ 37.9
Share-based compensation expense	(0.2)	0.7	2.2	0.9
Non-Cash:				
Share-based compensation expense	4.3	4.1	18.4	15.6
Equity swap loss/(gain)	0.2	(0.8)	(1.2)	0.2
Total G&A expenses	$ 16.3	$ 15.7	$ 56.7	$ 54.6

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2018	2017	2018	2017
Cash:				
G&A expense	$ 1.35	$ 1.61	$ 1.49	$ 1.67
Share-based compensation expense	(0.02)	0.10	0.09	0.04
Non-Cash:				
Share-based compensation expense	0.48	0.57	0.74	0.69
Equity swap loss/(gain)	0.02	(0.11)	(0.05)	0.01
Total G&A expenses	$ 1.83	$ 2.17	$ 2.27	$ 2.41

For the three and nine months ended September 30, 2018, cash G&A expenses were $12.0 million ($1.35/BOE) and $37.3 million ($1.49/BOE), respectively, compared to $11.7 million ($1.61/BOE) and $37.9 million ($1.67/BOE) for the same periods in 2017. Cash G&A expenses were essentially flat but decreased on a per BOE basis for the three and nine months ended September 30, 2018 compared to the same periods in 2017, due to higher production.

During the third quarter of 2018, we reported a cash SBC recovery of $0.2 million due to the decrease in our share price on outstanding deferred share units. We recorded non-cash SBC of $4.3 million or $0.48/BOE in the third quarter of 2018, which is consistent with an expense of $4.1 million or $0.57/BOE during the same period in 2017.

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. In the third 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. We had 195,000 units outstanding, hedged at a weighted average price of $20.60 per share at September 30, 2018.

We are lowering our annual cash G&A guidance to $1.50/BOE from $1.55/BOE due to higher annual average production.

Interest Expense

For the three and nine months ended September 30, 2018, we recorded total interest expense of $8.6 million and $27.0 million, respectively, compared to $8.7 million and $29.0 million for the same periods in 2017. The decrease in interest expense for the nine months ended September 30, 2018 compared to the same period in 2017 was primarily due to the repayment of a portion of our 2009 senior notes which carry a higher coupon rate, along with the impact of a strengthening Canadian dollar on our U.S. dollar denominated interest expense.

At September 30, 2018, 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 4.8%. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Realized:				
Foreign exchange (gain)/loss on settlements	$ 0.3	$ 0.5	$ 0.6	$ 1.5
Translation of U.S. dollar cash held in Canada (gain)/loss	4.3	13.5	(6.8)	13.5
Unrealized (gain)/loss	(12.2)	(31.6)	17.9	(48.6)
Total foreign exchange (gain)/loss	$ (7.6)	$ (17.6)	$ 11.7	$ (33.6)
USD/CDN average exchange rate	1.31	1.25	1.29	1.31
USD/CDN period end exchange rate	1.29	1.25	1.29	1.25

For the three and nine months ended September 30, 2018, we recorded a foreign exchange gain of $7.6 million and loss of $11.7 million, respectively, compared to gains of $17.6 million and $33.6 million for the same periods in 2017. Realized gains and losses include day-to-day transactions recorded in foreign currencies, and 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 September 30, 2018 to December 31, 2017, the Canadian dollar weakened relative to the U.S. dollar, resulting in an unrealized loss of $17.9 million. See Note 12 to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Capital spending	$ 193.3	$ 119.1	$ 521.8	$ 341.2
Office capital	1.6	0.5	5.3	1.0
Sub-total	194.9	119.6	527.1	342.2
Property and land acquisitions	$ 1.7	$ 2.2	$ 16.4	$ 9.5
Property divestments	0.8	1.4	(6.0)	(57.6)
Sub-total	2.5	3.6	10.4	(48.1)
Total (1)	$ 197.4	$ 123.2	$ 537.5	$ 294.1

(1) Excludes changes in non-cash investing working capital. See Note 17(b) to the Interim Financial Statements for further details.

Capital spending for the three and nine months ended September 30, 2018, totaled $193.3 million and $521.8 million, respectively, compared to capital spending of $119.1 million and $341.2 million for the same periods in 2017. The increase is in line with our strategy to deliver production and liquids growth through 2018. During the quarter we spent $159.4 million on our U.S. crude oil properties, $18.6 million on our Marcellus natural gas assets and $14.5 million on our Canadian waterflood properties.

For the three and nine months ended September 30, 2018, we completed $1.7 million and $16.4 million, respectively, in property and land acquisitions which included minor acquisitions of leases and undeveloped land. Property divestments for the nine months ended September 30, 2018 were $6.0 million compared to divestments with proceeds of $57.6 million in 2017, consisting mainly of our Brooks waterflood property and Canadian shallow gas assets.

We continue to expect 2018 annual capital spending of $585 million. Capital activity for the remainder of the year will be largely focused on drilling in North Dakota in preparation for the 2019 program.

Depletion, Depreciation and Accretion (“DD&A”)

($ millions, except per BOE amounts)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
DD&A expense	$ 81.5	$ 59.8	$ 218.7	$ 185.1
Per BOE	$ 9.15	$ 8.21	$ 8.74	$ 8.13

DD&A of property, plant and equipment (“PP&E”) is recognized using the unit-of-production method based on proved reserves. The increase in DD&A per BOE compared to the same periods of 2017 was a result of increased U.S. production with higher depletion rates.

Asset Retirement Obligation

In connection with our operations, we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are based on our net ownership interest and management's estimate of costs to abandon and reclaim such assets and the timing of the costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation to be $119.4 million at September 30, 2018, compared to $117.7 million at December 31, 2017. For the three and nine months ended September 30, 2018, asset retirement obligation settlements were $2.8 million and $8.1 million, respectively, compared to $3.1 million and $7.1 million during the same periods in 2017. See Note 9 to the Interim Financial Statements for further details.

Income Taxes

($ millions)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Current tax expense/(recovery)	$ 0.1	$ 0.1	$ 0.2	$ 2.2
Deferred tax expenses/(recovery)	15.0	(7.7)	30.7	59.4
Total tax expense/(recovery)	$ 15.1	$ (7.6)	$ 30.9	$ 61.6

For the three and nine months ended September 30, 2018, we recorded a total tax expense of $15.1 million and $30.9 million, respectively, compared to a recovery of $7.6 million and an expense of $61.6 million for the same periods in 2017. The increase in the total tax expense for the three months ended was primarily due to higher income in 2018 compared to the same period in 2017. The decrease in the total tax expense for the nine months ended was primarily due to lower net income in 2018 compared to the same period in 2017, as a result of commodity derivative hedging losses in 2018 compared to gains in 2017, and a gain of $78.4 million recorded on the divestment of assets in 2017. See Note 13 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 September 30, 2018, our senior debt to adjusted EBITDA ratio was 0.9x and our net debt to adjusted funds flow ratio was 0.4x. 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 September 30, 2018 was $313.6 million, a decrease of 4% compared to $325.8 million at December 31, 2017. Total debt was comprised of $661.2 million of senior notes less $347.6 million in cash. At September 30, 2018, we were undrawn on our $800 million bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by adjusted funds flow, was 96% and 102% for the three and nine months ended September 30, 2018, respectively, compared to 140% and 112% for the same periods in 2017.

For the three months ended September 30, 2018, the Company repurchased and cancelled 544,300 shares under our NCIB for a total cost of $8.5 million.

Our working capital deficiency, excluding cash and current deferred financial assets and liabilities, increased to $137.0 million at September 30, 2018 from $107.6 million at December 31, 2017. 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.

Subsequent to the quarter, we completed a one year extension of our $800 million senior, unsecured, covenant-based bank credit facility, which now matures on October 31, 2021. There were no significant amendments to the agreement terms or covenants. Drawn fees on the facility range between 125 and 315 basis points over Banker's Acceptance rates, with current drawn fees of 125 basis points over Banker's Acceptance rates based on our current reported senior net debt to adjusted EBITDA ratio. The bank credit facility ranks equally with our senior, unsecured covenant-based notes.

At September 30, 2018, 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 September 30, 2018:

Covenant Description		September 30, 2018
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%	25%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	20.0x

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 September 30, 2018 was $214.8 million and $734.8 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 for the senior notes, 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 September 30,		Nine months ended September 30,	
($ millions, except per share amounts)	2018	2017	2018	2017
Dividends to shareholders	$ 7.4	$ 7.3	$ 22.0	$ 21.8
Per weighted average share (Basic)	$ 0.03	$ 0.03	$ 0.09	$ 0.09

During the three and nine months ended September 30, 2018, we reported total dividends of $7.4 million or $0.03 per share and $22.0 million or $0.09 per share, respectively, compared to $7.3 million or $0.03 per share and $21.8 million or $0.09 per share for the same periods in 2017.

The dividend is part of our strategy to create shareholder value. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Nine months ended September 30,	
	2018	2017
Share capital ($ millions)	$ 3,412.2	$ 3,386.9
Common shares outstanding (thousands)	244,764	242,129
Weighted average shares outstanding – basic (thousands)	244,659	241,854
Weighted average shares outstanding – diluted (thousands)	250,048	247,306

For the nine months ended September 30, 2018, a total of 640,086 shares were issued pursuant to our stock option plan resulting in additional share capital of $8.7 million, and a $0.7 million transfer from paid-in capital to share capital (2017 – nil). For the nine months ended September 30, 2018, a total of 2,539,498 shares were issued pursuant to our treasury-settled LTI plans and $23.4 million was transferred from paid-in capital to share capital (2017 – 1,646,017; $21.0 million).

During the three months ended September 30, 2018, the Company repurchased 544,300 common shares under the NCIB at an average price of $15.54 per share, for total consideration of $8.5 million. Of the amount paid, $7.6 million was recorded to share capital and $0.9 million was recorded to accumulated deficit. Subsequent to the quarter, the Company repurchased 1,071,366 common shares under the NCIB at an average price of $15.42 per share.

At November 8, 2018, we had 243,750,520 common shares outstanding. In addition, an aggregate of 11,326,078 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 14 to the Interim Financial Statements.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

($ millions, except per unit amounts)	Three months ended September 30, 2018 Canada	U.S.	Total	Three months ended September 30, 2017 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	9,170	39,697	48,867	9,924	25,321	35,245
Natural gas liquids (bbls/day)	1,002	3,561	4,563	975	2,706	3,681
Natural gas (Mcf/day)	24,486	236,105	260,591	32,864	208,348	241,212
Total average daily production (BOE/day)	14,253	82,608	96,861	16,376	62,752	79,128
Pricing[2]						
Crude oil (per bbl)	$ 69.12	$ 87.42	$ 83.98	$ 48.68	$ 56.38	$ 54.21
Natural gas liquids (per bbl)	45.44	20.47	25.95	33.23	23.69	26.22
Natural gas (per Mcf)	2.78	3.27	3.22	2.50	2.59	2.58
Capital Expenditures						
Capital spending	$ 15.3	$ 178.0	$ 193.3	$ 10.0	$ 109.1	$ 119.1
Acquisitions	0.9	0.8	1.7	0.8	1.4	2.2
Divestments	1.1	(0.3)	0.8	1.3	0.1	1.4
Netback[3] Before Hedging						
Oil and natural gas sales	$ 69.4	$ 397.0	$ 466.4	$ 55.0	$ 186.9	$ 241.9
Royalties	(13.4)	(79.4)	(92.8)	(9.2)	(36.6)	(45.8)
Production taxes	(1.1)	(25.5)	(26.6)	(0.7)	(11.6)	(12.3)
Cash operating expenses	(19.1)	(41.5)	(60.6)	(18.0)	(30.9)	(48.9)
Transportation costs	(2.9)	(30.1)	(33.0)	(2.9)	(23.4)	(26.3)
Netback before hedging	$ 32.9	$ 220.5	$ 253.4	$ 24.2	$ 84.4	$ 108.6
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 54.1	$ —	$ 54.1	$ 34.2	$ —	$ 34.2
General and administrative expense[4]	9.9	6.4	16.3	9.2	6.5	15.7
Current income tax expense/(recovery)	(0.4)	0.5	0.1	(0.4)	0.5	0.1

($ millions, except per unit amounts)	Nine months ended September 30, 2018 Canada	U.S.	Total	Nine months ended September 30, 2017 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	9,297	34,595	43,892	11,217	23,885	35,102
Natural gas liquids (bbls/day)	1,100	3,387	4,487	1,191	2,468	3,659
Natural gas (Mcf/day)	28,891	230,738	259,629	49,247	218,605	267,852
Total average daily production (BOE/day)	15,213	76,438	91,651	20,616	62,787	83,403
Pricing[2]						
Crude oil (per bbl)	$ 62.78	$ 82.83	$ 78.58	$ 50.39	$ 58.27	$ 55.75
Natural gas liquids (per bbl)	46.84	23.00	28.85	36.12	25.70	29.09
Natural gas (per Mcf)	2.67	3.19	3.14	3.37	3.24	3.26
Capital Expenditures						
Capital spending	$ 39.8	$ 482.0	$ 521.8	$ 45.6	$ 295.6	$ 341.2
Acquisitions	3.0	13.4	16.4	3.5	6.0	9.5
Divestments	0.3	(6.3)	(6.0)	(57.5)	(0.1)	(57.6)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 197.0	$ 1,004.8	$ 1,201.8	$ 211.4	$ 590.3	$ 801.7
Royalties	(34.2)	(201.6)	(235.8)	(35.4)	(116.7)	(152.1)
Production taxes	(2.6)	(62.8)	(65.4)	(2.6)	(33.9)	(36.5)
Cash operating expenses	(57.3)	(118.0)	(175.3)	(63.9)	(81.5)	(145.4)
Transportation costs	(8.8)	(81.3)	(90.1)	(10.4)	(74.7)	(85.1)
Netback before hedging	$ 94.1	$ 541.1	$ 635.2	$ 99.1	$ 283.5	$ 382.6
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 165.5	$ —	$ 165.5	$ (55.3)	$ —	$ (55.3)
General and administrative expense[4]	31.6	25.1	56.7	35.0	19.6	54.6
Current income tax expense/(recovery)	(0.4)	0.6	0.2	(0.4)	2.6	2.2

(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
2018				
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	$ 966.0	$ 128.9	$ 0.53	$ 0.52
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
2016				
Fourth Quarter	$ 217.4	$ 840.3	$ 3.49	$ 3.43
Third Quarter	188.3	(100.7)	(0.42)	(0.42)
Second Quarter	174.3	(168.5)	(0.77)	(0.77)
First Quarter	142.7	(173.7)	(0.84)	(0.84)
Total 2016	$ 722.7	$ 397.4	$ 1.75	$ 1.72

Oil and natural gas sales, net of royalties, increased in the third quarter of 2018 compared to the second quarter of 2018 due to increased production volumes and higher realized crude oil and natural gas prices. Net income increased in the third quarter of 2018 compared to the second quarter of 2018 due to an increase in sales and a decrease in losses from commodity derivative instruments. Oil and natural gas sales, net of royalties, have continued to improve in 2018 compared to 2017 and 2016 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. Net income has continued to improve in 2018, excluding the effects of a gain which was recorded on asset divestments in the second quarter of 2017 and reversal of valuation allowance on deferred tax asset in the fourth quarter of 2016.

2018 UPDATED GUIDANCE

We are revising our average annual production guidance range to 92,500 – 93,000 BOE/day, the high end of our previous range of 91,000 – 93,000 BOE/day. We are also revising our average annual crude oil and liquids guidance range to 49,500 – 50,000 bbls/day, the high end of our previous range of 49,000 – 50,000 bbls/day and guiding to a fourth quarter average crude oil and liquids production range of 53,500 – 54,500 bbls/day.

We are maintaining our operating cost guidance of $7.00/BOE and reaffirming our annual capital spending guidance of $585 million. With higher annual average production, we are reducing our annual cash G&A guidance to $1.50/BOE from $1.55/BOE.

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

Summary of 2018 Expectations	Target
Capital spending	$585 million
Average annual production	92,500 - 93,000 BOE/day (from 91,000 - 93,000 BOE/day)
Average annual crude oil and natural gas liquids production	49,500 - 50,000 bbls/day (from 49,000 - 50,000 bbls/day)
Fourth quarter average crude oil and natural gas liquids	53,500 - 54,500 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	25%
Operating expenses	$7.00/BOE
Transportation costs	$3.60/BOE
Cash G&A expenses	$1.50/BOE (from $1.55/BOE)

2018 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.80)/bbl (from US$(3.50)/bbl)
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.40)/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 September 30,**		**Nine months ended September 30,**	
($ millions)	**2018**	**2017**	**2018**	**2017**
Oil and natural gas sales	$ 466.4	$ 241.9	$ 1,201.8	$ 801.7
Less:				
Royalties	(92.8)	(45.8)	(235.8)	(152.1)
Production taxes	(26.6)	(12.3)	(65.4)	(36.5)
Cash operating expenses[1]	(60.6)	(48.9)	(175.3)	(145.4)
Transportation costs	(33.0)	(26.3)	(90.1)	(85.1)
Netback before hedging	$ 253.4	$ 108.6	$ 635.2	$ 382.6
Cash gains/(losses) on derivative instruments	(23.9)	2.9	(33.0)	11.7
Netback after hedging	$ 229.5	$ 111.5	$ 602.2	$ 394.3

(1) Total operating expenses have been adjusted to exclude a non-cash loss of $0.1 million and nil for the three and nine months ended September 30, 2018, and non-cash gains of $0.1 million and $0.4 million, respectively, for the three and nine months ended September 30, 2017.

"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 September 30,**		**Nine months ended September 30,**	
($ millions)	**2018**	**2017**	**2018**	**2017**
Cash flow from operating activities	$ 216.1	$ 114.6	$ 517.2	$ 340.8
Asset retirement obligation expenditures	2.8	3.1	8.1	7.1
Changes in non-cash operating working capital	(8.5)	(27.3)	13.9	(23.4)
Adjusted funds flow	$ 210.4	$ 90.4	$ 539.2	$ 324.5

"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 exploration and development capital.

"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 restricted cash.

"**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 and office expenditures divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	**Three months ended September 30,**		**Nine months ended September 30,**	
($ millions)	**2018**	**2017**	**2018**	**2017**
Dividends	$ 7.4	$ 7.3	$ 22.0	$ 21.8
Capital and office expenditures	194.9	119.6	527.1	342.2
Sub-total	$ 202.3	$ 126.9	$ 549.1	$ 364.0
Adjusted funds flow	$ 210.4	$ 90.4	$ 539.2	$ 324.5
Adjusted payout ratio (%)	96%	140%	102%	112%

"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)		September 30, 2018
Net income/(loss)	$	144.2
Add:		
Interest		36.7
Current and deferred tax expense/(recovery)		51.4
DD&A and asset impairment		284.4
Other non-cash charges[2]		218.1
Adjusted EBITDA	$	734.8

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at September 30, 2018 include the nine months ended September 30, 2018 and the fourth quarter of 2017.
(2) Includes the change in fair value of commodity derivatives, fixed price electricity swaps and equity swaps, non-cash SBC 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", "senior net debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "maximum 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 September 30, 2018, 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 July 1, 2018 and ended September 30, 2018 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 2018 average production volumes 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; anticipated production volumes subject to curtailment; 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 2018 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; operating and transportation costs; capital spending levels in 2018 and impact thereof on our production levels; 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 2018 guidance contained in this MD&A is based on the following forward prices: a WTI price of US$66.86/bbl, a NYMEX price of US$2.96/Mcf, and a USD/CDN exchange rate of 1.29. 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, 2017).

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.