Exhibit 99.1

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

The following discussion and analysis of financial results is dated August 9, 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 six months ended June 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 second quarter averaged 92,883 BOE/day, a 9% increase compared to the first quarter of 2018. Our crude oil and natural gas liquids production increased by 21% to 50,050 bbls/day from 41,528 bbls/day in the first quarter of 2018, coming in at the top end of our second quarter crude oil and natural gas liquids production range of 48,000 – 50,000 bbls/day. The increase in production is due to strong well performance in North Dakota with 11.0 net wells brought on-stream during the period, as well as less downtime related to offset completions on adjacent properties when compared to the first quarter of 2018. As a result of outperformance in North Dakota and higher non-operated production in the Marcellus, we are increasing our average annual production range to 91,000 – 93,000 BOE/day (from 86,000 – 91,000 BOE/day) and narrowing our average annual crude oil and liquids guidance range to 49,000 – 50,000 bbls/day (from 46,000 – 50,000 bbls/day).

Our capital spending for the second quarter totaled $177.1 million, with the majority directed to our North Dakota crude oil properties. We are revising our annual capital spending guidance to $585 million (previous guidance range of $535 – $585 million), due to non-operated capital in both North Dakota and the Marcellus, as well as modest cost increases on a portion of our materials and services.

Operating costs for the quarter increased to $60.9 million or $7.20/BOE from $53.8 million or $7.02/BOE in the first quarter of 2018. The increase in operating costs from the first quarter of 2018 was mainly due to a higher crude oil and liquids production weighting in the second quarter with higher per BOE operating costs, along with water handling rate increases. We are maintaining our annual operating cost guidance of $7.00/BOE.

Cash G&A expenses for the second quarter were $12.1 million or $1.44/BOE, a decrease of 16% on a per BOE basis from $1.72/BOE in the first quarter of 2018. Cash G&A expenses per BOE decreased from the first quarter with higher production during the period. We are lowering our annual guidance target for cash G&A expenses to $1.55/BOE from $1.65/BOE.

We continued to add to our commodity hedge positions during the quarter. As of August 9, 2018, we had approximately 66% of our forecasted crude oil production, net of royalties, hedged for the remainder of 2018, and approximately 69% and 42% 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 19% of our forecasted natural gas production, net of royalties, for the remainder of 2018.

We recorded net income of $12.4 million and adjusted funds flow of $173.7 million in the second quarter of 2018, compared to $29.6 million and $155.2 million, respectively, in the first quarter of 2018. Net income in the second quarter was impacted by non-cash mark-to-market losses recorded on our commodity derivative instruments, offset by higher realized commodity prices and production.

At June 30, 2018, our total debt net of cash was $311.8 million and our net debt to adjusted funds flow ratio was 0.5x.

RESULTS OF OPERATIONS

Production

Production for the second quarter averaged 92,883 BOE/day, an increase of 7,803 BOE/day or 9% compared to the first quarter of 2018. Crude oil and natural gas liquids production increased by 21%, primarily due to higher North Dakota volumes. The increase was due to the strong well performance of the 11.0 net wells coming on-stream during the second quarter, as well as less downtime from completions activities occurring on adjacent properties.

For the three and six months ended June 30, 2018, crude oil and liquids production increased by 9,056 bbls/day or 22% and 7,135 bbls/day or 18%, respectively, compared to the same periods in 2017. Production increased primarily due to higher spending in North Dakota where we had 16.2 net wells come on-stream year-to-date. This increase was offset somewhat by the impact of 2017 Canadian crude oil asset divestments. Natural gas production decreased by 5% and 8% over the same respective periods due to non-core Canadian asset divestments in the first half of 2017.

Our crude oil and natural gas liquids weighting increased to 54% in the second quarter of 2018, from 48% for the same period of 2017, due to increased capital spending on our North Dakota crude oil asset and the divestment of non-core Canadian natural gas weighted properties.

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

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2018**	**2017**	**% Change**	**2018**	**2017**	**% Change**
Crude oil (bbls/day)	45,242	36,861	23%	41,364	35,030	18%
Natural gas liquids (bbls/day)	4,808	4,133	16%	4,449	3,648	22%
Natural gas (Mcf/day)	256,995	271,292	(5%)	259,141	281,393	(8%)
Total daily sales (BOE/day)	92,883	86,209	8%	89,003	85,577	4%

Based on strong performance in North Dakota and higher non-operated production in the Marcellus, we are increasing our average annual production guidance range to 91,000 – 93,000 BOE/day (from 86,000 – 91,000 BOE/day) and narrowing our average annual crude oil and liquids guidance range to 49,000 – 50,000 bbls/day (from 46,000 – 50,000 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 from the first half of 2018 to the first half of 2017 and other periods indicated:

Pricing (average for the period)	Six months ended June 30, 2018	Six months ended June 30, 2017	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017
Benchmarks							
WTI crude oil (US$/bbl)	$ 65.37	$ 50.10	$ 67.88	$ 62.87	$ 55.40	$ 48.20	$ 48.29
AECO natural gas – monthly index ($/Mcf)	1.44	2.86	1.02	1.85	1.96	2.04	2.77
AECO natural gas – daily index ($/Mcf)	1.63	2.74	1.18	2.08	1.69	1.45	2.78
NYMEX natural gas – last day (US$/Mcf)	2.90	3.25	2.80	3.00	2.93	3.00	3.18
USD/CDN average exchange rate	1.28	1.33	1.29	1.26	1.27	1.25	1.34
USD/CDN period end exchange rate	1.31	1.30	1.31	1.29	1.26	1.25	1.30
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 75.34	$ 56.54	$ 79.98	$ 69.67	$ 65.91	$ 54.21	$ 55.66
Natural gas liquids ($/bbl)	30.36	30.57	32.23	28.13	32.26	26.22	25.14
Natural gas ($/Mcf)	3.09	3.56	2.68	3.50	3.03	2.58	3.48
Average differentials							
MSW Edmonton – WTI (US$/bbl)	$ (5.67)	$ (2.90)	$ (5.45)	$ (5.89)	$ (1.14)	$ (2.89)	$ (2.26)
WCS Hardisty – WTI (US$/bbl)	(21.78)	(12.85)	(19.27)	(24.28)	(12.27)	(9.94)	(11.13)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.79)	(0.61)	(0.91)	(0.67)	(1.32)	(1.29)	(0.60)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.88)	(0.68)	(0.99)	(0.76)	(1.40)	(1.36)	(0.66)
AECO monthly – NYMEX (US$/Mcf)	(1.72)	(1.12)	(2.00)	(1.44)	(1.40)	(1.39)	(1.13)
Enerplus realized differentials(1)(2)							
Canada crude oil – WTI (US$/bbl)	$ (18.52)	$ (11.95)	$ (16.31)	$ (20.82)	$ (10.47)	$ (9.29)	$ (11.02)
Canada natural gas – NYMEX (US$/Mcf)	(0.84)	(0.56)	(1.18)	(0.52)	(0.56)	(1.00)	(0.51)
Bakken crude oil – WTI (US$/bbl)	(3.34)	(5.49)	(3.42)	(3.27)	(1.61)	(3.24)	(5.43)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.45)	(0.62)	(0.69)	(0.21)	(0.81)	(1.02)	(0.64)

(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 second quarter of 2018 increased by 15%, compared to the first quarter of 2018, to average $79.98/bbl. Benchmark WTI crude oil prices increased by 8% comparatively, based on a continued reduction in global crude oil inventories and concerns over the Organization of the Petroleum Exporting Countries ("OPEC") production outlook, particularly in Venezuela and Iran. A weaker Canadian dollar and stronger Canadian crude oil differentials also contributed to the overall realized price increase.

Our realized Bakken price differential to WTI increased by US$0.15/bbl during the quarter to average US$3.42/bbl below WTI, in line with our annual guidance of US$3.50/bbl. Bakken crude oil differentials continue to benefit from improved egress out of the area due to the Dakota Access Pipeline, which has a direct link to the U.S. Gulf Coast, and significant rail takeaway capacity to the U.S. East, West, and Gulf coasts. We continue to expect our annual Bakken crude oil differential to average US$3.50/bbl below WTI.

Our realized price differential for our Canadian crude oil production decreased in the second quarter of 2018 by US$4.51/bbl compared to the previous quarter. Canadian crude oil prices improved during the quarter as pipeline apportionment concerns subsided primarily due to an increase in rail takeaway capacity. Our realized price for natural gas liquids averaged $32.23/bbl during the second quarter, which represents a 15% increase compared to the first quarter of 2018, and is consistent with the increase in benchmark prices.

NATURAL GAS

Our average realized natural gas price during the second quarter of 2018 decreased by 23% compared to the first quarter of 2018, to average $2.68/Mcf. The decrease was due to a reduction in benchmark NYMEX and regional pricing. Our realized Marcellus sales price differential, excluding transportation and gathering costs, weakened considerably compared to the first quarter, to average US$0.69/Mcf below NYMEX. This weakness was mainly due to pipeline maintenance issues in the region as well as seasonal factors after experiencing very strong prices in the first quarter due to a colder than expected winter. We continue to expect an improvement in Marcellus differentials going forward as more pipeline projects are completed and brought into service during the second half of 2018. We are maintaining our annual guidance of US$0.40/Mcf below NYMEX.

Benchmark AECO gas prices continue to remain weak due to transportation constraints out of the basin. Our realized Canadian natural gas price differential averaged US$1.18/Mcf below NYMEX. We continue to benefit from our multi-year term AECO 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 relative to the U.S. dollar impacts both our revenue as well as our U.S. denominated costs. The stronger Canadian dollar decreases the amount of our realized sales, as well as the amount of our U.S. dollar 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 six months of 2018 with an average exchange rate of 1.28 USD/CDN compared to 1.33 USD/CDN for the same period in 2017. However, when compared to the first quarter of 2018, and the exchange rate at December 31, 2017, 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, as well as other U.S policies related to trade and 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 August 9, 2018, we have hedged approximately 22,000 bbls/day of our expected crude oil production for the remainder of 2018, which represents approximately 66% of our forecasted crude oil production, after royalties. For 2019, we are hedged on approximately 23,140 bbls/day, which represents approximately 69% of our 2018 forecasted crude oil production, after royalties. For 2020, we have hedged 14,000 bbls/day, which represents 42% 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 August 9, 2018, we have hedged approximately 36,685 Mcf/day of our forecasted natural gas production for the remainder of 2018. This represents approximately 19% of our forecasted natural gas production, after royalties.

The following is a summary of our financial contracts in place at August 9, 2018, expressed as a percentage of our forecasted 2018 net production volumes:

	WTI Crude Oil (US$/bbl)[1]						
	Jul 1, 2018 – Sep 30, 2018	**Oct 1, 2018 – Dec 31, 2018**	**Jan 1, 2019 – Mar 31, 2019**	**Apr 1, 2019 – Jun 30, 2019**	**Jul 1, 2019 – Sep 30, 2019**	**Oct 1, 2019 – Dec 31, 2019**	**Jan 1, 2020 – Dec 31, 2020**
Swaps							
Sold Swaps	$ 53.73	$ 53.73	$ 53.73	—	—	—	—
%	9%	9%	9%	—	—	—	—
Three Way Collars[2]							
Sold Puts	$ 42.71	$ 42.74	$ 44.28	$ 44.50	$ 44.64	$ 44.64	$ 46.71
%	54%	60%	51%	70%	73%	73%	42%
Purchased Puts	$ 52.53	$ 52.48	$ 54.12	$ 54.59	$ 54.81	$ 54.81	$ 57.14
%	54%	60%	51%	70%	73%	73%	42%
Sold Calls	$ 61.22	$ 61.10	$ 64.12	$ 65.52	$ 65.95	$ 65.99	$ 72.07
%	54%	60%	51%	70%	73%	73%	42%

(1) Based on weighted average price (before premiums) assuming average annual production of 92,000 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$1.59/bbl from July 1, 2018 to December 31, 2020.

	NYMEX Natural Gas (US$/Mcf)[(1)]	
	Jul 1, 2018 – Oct 31, 2018	Nov 1, 2018 – Dec 31, 2018
Collars		
Purchased Puts	$ 2.75	$ 2.75
%	21%	16%
Sold Calls	$ 3.38	$ 3.47
%	21%	16%

(1) Based on weighted average price assuming average annual production of 92,000 BOE/day, which is the mid-point of our updated annual 2018 guidance, less royalties and production taxes of 25%.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	Three months ended June 30,		Six months ended June 30,	
($ millions)	2018	2017	2018	2017
Cash gains/(losses):				
Crude oil	$ (20.1)	$ 2.2	$ (26.4)	$ 1.3
Natural gas	0.8	—	17.3	7.5
Total cash gains/(losses)	$ (19.3)	$ 2.2	$ (9.1)	$ 8.8
Non-cash gains/(losses):				
Crude oil	$ (70.9)	$ 27.3	$ (100.8)	$ 71.6
Natural gas	(0.8)	2.4	(1.5)	9.1
Total non-cash gains/(losses)	$ (71.7)	$ 29.7	$ (102.3)	$ 80.7
Total gains/(losses)	$ (91.0)	$ 31.9	$ (111.4)	$ 89.5

	Three months ended June 30,		Six months ended June 30,	
(Per BOE)	2018	2017	2018	2017
Total cash gains/(losses)	$ (2.28)	$ 0.28	$ (0.57)	$ 0.57
Total non-cash gains/(losses)	(8.48)	3.79	(6.35)	5.21
Total gains/(losses)	$ (10.76)	$ 4.07	$ (6.92)	$ 5.78

During the second quarter of 2018, we realized cash losses of $20.1 million on our crude oil contracts and cash gains of $0.8 million on our natural gas contracts. In comparison, during the second quarter of 2017, we realized cash gains of $2.2 million on our crude oil contracts. Cash losses on 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 second quarter of 2018, the fair value of our crude oil contracts was in a net liability position of $135.0 million, while the fair value of our natural gas contracts was in a net asset position of $0.2 million. For the three and six months ended June 30, 2018, the change in the fair value of our crude oil contracts represented losses of $70.9 million and $100.8 million, respectively, and our natural gas contracts represented losses of $0.8 million and $1.5 million, respectively.

Revenues

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2018	2017	2018	2017
Oil and natural gas sales	$ 406.8	$ 282.1	$ 735.3	$ 559.8
Royalties	(79.4)	(56.4)	(142.9)	(106.3)
Oil and natural gas sales, net of royalties	$ 327.4	$ 225.7	$ 592.4	$ 453.5

Oil and natural gas sales, net of royalties for the three and six months ended June 30, 2018, were $327.4 million and $592.4 million, respectively, an increase of 45% and 31% from the same periods in 2017. The increase in revenue was a result of the improvement in crude oil prices in the period, along with a higher crude oil and natural gas liquids weighting compared to the prior year.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended June 30, 2018	2017	Six months ended June 30, 2018	2017
Royalties	$ 79.4	$ 56.4	$ 142.9	$ 106.3
Per BOE	$ 9.40	$ 7.19	$ 8.87	$ 6.86
Production taxes	$ 22.6	$ 13.8	$ 38.8	$ 24.2
Per BOE	$ 2.68	$ 1.76	$ 2.41	$ 1.56
Royalties and production taxes	$ 102.0	$ 70.2	$ 181.7	$ 130.5
Per BOE	$ 12.08	$ 8.95	$ 11.28	$ 8.42
Royalties and production taxes (% of oil and natural gas sales)	25%	25%	25%	23%

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 less sensitive to commodity price levels. During the three and six months ended June 30, 2018, royalties and production taxes increased to $102.0 million and $181.7 million, respectively, from $70.2 million and $130.5 million for the same periods in 2017 primarily due to higher crude oil sales. In the second quarter of 2018, royalties and production taxes averaged 25%, consistent with the same period in 2017.

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

Operating Expenses

($ millions, except per BOE amounts)	Three months ended June 30, 2018	2017	Six months ended June 30, 2018	2017
Cash operating expenses	$ 61.0	$ 46.2	$ 114.7	$ 96.4
Non-cash (gains)/losses(1)	(0.1)	(0.4)	(0.1)	(0.3)
Total operating expenses	$ 60.9	$ 45.8	$ 114.6	$ 96.1
Per BOE	$ 7.20	$ 5.83	$ 7.12	$ 6.21

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

For the three and six months ended June 30, 2018, operating expenses were $60.9 million ($7.20/BOE) and $114.6 million ($7.12/BOE) respectively, compared to our annual guidance of $7.00/BOE. Operating costs increased from $45.8 million ($5.83/BOE) and $96.1 million ($6.21/BOE), respectively, in the same periods in 2017. The increases were due to a higher weighting of U.S. crude oil and liquids production with higher associated per BOE costs, including higher water handling rates.

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

Transportation Costs

($ millions, except per BOE amounts)	Three months ended June 30, 2018	2017	Six months ended June 30, 2018	2017
Transportation costs	$ 30.1	$ 29.2	$ 57.0	$ 58.8
Per BOE	$ 3.56	$ 3.72	$ 3.54	$ 3.80

For the three and six months ended June 30, 2018, transportation costs were $30.1 million ($3.56/BOE) and $57.0 million ($3.54/BOE) respectively, compared to our guidance of $3.60/BOE. During the same periods in 2017, transportation costs were $29.2 million ($3.72/BOE) and $58.8 million ($3.80/BOE), respectively. The decrease in costs on a per BOE basis for the three and six months ended June 30, 2018 was primarily due to a strengthening Canadian dollar.

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

Netbacks by Property Type	Three months ended June 30, 2017 Crude Oil	Natural Gas	Total
Average Daily Production	44,678 BOE/day	249,180 Mcfe/day	86,209 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 50.22	$ 3.44	$ 35.96
Royalties and production taxes	(13.82)	(0.62)	(8.95)
Cash operating expenses	(10.06)	(0.23)	(5.88)
Transportation costs	(2.35)	(0.87)	(3.72)
Netback before hedging	$ 23.99	$ 1.72	$ 17.41
Cash hedging gains/(losses)	0.55	—	0.28
Netback after hedging	$ 24.54	$ 1.72	$ 17.69
Netback before hedging ($ millions)	$ 97.5	$ 39.0	$ 136.5
Netback after hedging ($ millions)	$ 99.7	$ 39.0	$ 138.7

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

Netbacks by Property Type	Six months ended June 30, 2017 Crude Oil	Natural Gas	Total
Average Daily Production	42,546 BOE/day	258,180 Mcfe/day	85,577 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 51.21	$ 3.54	$ 36.14
Royalties and production taxes	(13.24)	(0.61)	(8.42)
Cash operating expenses	(10.16)	(0.39)	(6.23)
Transportation costs	(2.42)	(0.86)	(3.80)
Netback before hedging	$ 25.39	$ 1.68	$ 17.69
Cash hedging gains/(losses)	0.17	0.16	0.57
Netback after hedging	$ 25.56	$ 1.84	$ 18.26
Netback before hedging ($ millions)	$ 195.6	$ 78.5	$ 274.1
Netback after hedging ($ millions)	$ 196.8	$ 86.1	$ 282.9

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

Crude oil netbacks per BOE before hedging were higher for the three and six months ended June 30, 2018, compared to the same periods in 2017 primarily due to higher crude oil production and improved realized prices. Natural gas netbacks before hedging were lower for the first and second quarters of 2018 compared to the same periods in 2017 mainly due to lower production as a result of the divestment of non-core Canadian natural gas properties and weaker realized prices. For the three and six months ended June 30, 2018, our crude oil properties accounted for 91% and 86% of our netback before hedging, respectively, compared to 71% for the three and six 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 June 30,		Six months ended June 30,	
($ millions)	2018	2017	2018	2017
Cash:				
G&A expense	$ 12.1	$ 12.0	$ 25.3	$ 26.3
Share-based compensation expense	0.5	—	2.4	0.1
Non-Cash:				
Share-based compensation expense	5.0	3.3	14.1	11.4
Equity swap loss/(gain)	(0.4)	—	(1.4)	1.0
Total G&A expenses	$ 17.2	$ 15.3	$ 40.4	$ 38.8

	Three months ended June 30,		Six months ended June 30,	
(Per BOE)	2018	2017	2018	2017
Cash:				
G&A expense	$ 1.44	$ 1.53	$ 1.57	$ 1.69
Share-based compensation expense	0.05	—	0.16	0.01
Non-Cash:				
Share-based compensation expense	0.59	0.42	0.87	0.74
Equity swap loss/(gain)	(0.04)	0.01	(0.09)	0.07
Total G&A expenses	$ 2.04	$ 1.96	$ 2.51	$ 2.51

For the three months and six months ended June 30, 2018, cash G&A expenses were $12.1 million ($1.44/BOE) and $25.3 million ($1.57/BOE), respectively, compared to $12.0 million ($1.53/BOE) and $26.3 million ($1.69/BOE) for the same periods in 2017. Cash G&A expenses decreased on a per BOE basis for the three and six months ended June 30, 2018 compared to the same periods in 2017, primarily due to higher production.

During the second quarter of 2018, we reported cash SBC expense of $0.5 million due to the increase in our share price on outstanding deferred share units, offset by a gain on the unwind of a portion of our outstanding equity hedge contracts. We recorded non-cash SBC of $5.0 million or $0.59/BOE in the second quarter of 2018, which increased from $3.3 million or $0.42/BOE during the same period in 2017 with an increase in the performance multiplier of our Performance Share Unit plan in late 2017.

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. In the second quarter of 2018 we recorded a non-cash mark-to-market gain of $0.4 million on these hedges due to the increase in our share price. As a result of the settlement of the equity hedge contracts during the quarter, we had 195,000 units outstanding, hedged at a weighted average price of $20.60 per share at June 30, 2018.

Based on higher annual production levels and continued focus on costs, we are lowering our annual cash G&A guidance to $1.55/BOE from $1.65/BOE.

Interest Expense

For the three and six months ended June 30, 2018, we recorded total interest expense of $9.2 million and $18.4 million, respectively, compared to $10.2 million and $20.4 million for the same periods in 2017. The decrease in interest expense for the three and six months ended June 30, 2018 compared to the same periods in 2017, was primarily due to the impact of a strengthening Canadian dollar on our U.S. dollar denominated interest expense, along with the repayment of a portion of our US$110 million senior notes in June 2017 and 2018 which carry a higher coupon rate.

At June 30, 2018, all of our debt was based on 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 June 30, 2018	2017	Six months ended June 30, 2018	2017
Realized:				
Foreign exchange (gain)/loss on settlements	$ 0.2	$ 0.9	$ 0.3	$ 1.0
Translation of U.S. dollar cash held in Canada (gain)/loss	(3.7)	—	(11.0)	—
Unrealized (gain)/loss	12.4	(13.1)	30.0	(17.0)
Total foreign exchange (gain)/loss	$ 8.9	$ (12.2)	$ 19.3	$ (16.0)
USD/CDN average exchange rate	1.29	1.34	1.28	1.33
USD/CDN period end exchange rate	1.31	1.30	1.31	1.30

For the three and six months ended June 30, 2018, we recorded net foreign exchange losses of $8.9 million and $19.3 million, respectively, compared to gains of $12.2 million and $16.0 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 June 30, 2018 to December 31, 2017, the Canadian dollar weakened relative to the U.S. dollar, resulting in an unrealized loss of $30.0 million. See Note 12 to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended June 30, 2018	2017	Six months ended June 30, 2018	2017
Capital spending	$ 177.1	$ 101.7	$ 328.6	$ 222.1
Office capital	2.3	0.3	3.7	0.4
Sub-total	179.4	102.0	332.3	222.5
Property and land acquisitions	$ 2.4	$ 4.7	$ 14.7	$ 7.2
Property divestments	0.2	(59.8)	(6.8)	(58.9)
Sub-total	2.6	(55.1)	7.9	(51.7)
Total (1)	$ 182.0	$ 46.9	$ 340.2	$ 170.8

(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 six months ended June 30, 2018, totaled $177.1 million and $328.6 million, respectively, compared to the spending of $101.7 million and $222.1 million for the same periods in 2017. The increase in spending is in line with our strategy to deliver production and liquids growth through 2018. During the quarter we spent $141.8 million on our U.S. crude oil properties, $23.9 million on our Marcellus natural gas assets and $9.0 million on our Canadian waterflood properties.

In the second quarter of 2018, we completed $2.4 million in property and land acquisitions which included minor acquisitions of leases and undeveloped land. There were no asset divestments in the second quarter of 2018, compared to divestments with proceeds of $59.6 million, after closing adjustments, for the same period in 2017.

We are revising our annual capital spending guidance to $585 million (previous guidance range of $535 – $585 million), due to non-operated capital spending in North Dakota and the Marcellus, as well as modest increases on a portion of our materials and services.

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

($ millions, except per BOE amounts)	Three months ended June 30, 2018	2017	Six months ended June 30, 2018	2017
DD&A expense	$ 73.2	$ 64.8	$ 137.2	$ 125.4
Per BOE	$ 8.66	$ 8.26	$ 8.52	$ 8.09

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 $121.5 million at June 30, 2018, compared to $117.7 million at December 31, 2017. For the three and six months ended June 30, 2018, asset retirement obligation settlements were $2.1 million and $5.4 million, respectively, compared to $1.5 million and $4.1 million during the same periods in 2017. See Note 9 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2018	2017	2018	2017
Current tax expense/(recovery)	$ 0.1	$ 2.0	$ 0.1	$ 2.1
Deferred tax expenses/(recovery)	3.2	38.3	15.7	67.1
Total tax expense/(recovery)	$ 3.3	$ 40.3	$ 15.8	$ 69.2

For the three and six months ended June 30, 2018, we recorded a total tax expense of $3.3 million and $15.8 million, respectively, compared to $40.3 million and $69.2 million for the same periods in 2017. The decrease in the total tax expense is due to lower income in 2018, as well as a reduction to the U.S. federal income tax rate to 21% from 35% effective January 1, 2018 with the enactment of the U.S. Tax Cuts and Jobs Act. 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 and dividend levels. We also assess our leverage relative to our most restrictive debt covenant under our bank credit facility and senior notes, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At June 30, 2018, our senior debt to adjusted EBITDA ratio was 1.2x and our net debt to adjusted funds flow ratio was 0.5x. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate our liquidity.

Total debt net of cash at June 30, 2018 was $311.8 million, a decrease of 4% compared to $325.8 million at December 31, 2017. Total debt was comprised of $672.2 million of senior notes less $360.4 million in cash. At June 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 107% and 106% for the three and six months ended June 30, 2018, respectively, compared to 96% and 101% for the same periods in 2017.

Our working capital deficiency, excluding cash and current deferred financial assets and liabilities, increased to $144.3 million at June 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.

At June 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 June 30, 2018:

Covenant Description		June 30, 2018
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	1.2x
Total debt to adjusted EBITDA (1)	4.0x	1.2x
Total debt to capitalization	50%	20%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	1.2x
Senior debt to consolidated present value of total proved reserves(3)	60%	25%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	16.5

Definitions
"Senior debt" is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended June 30, 2018 was $186.7 million and $605.6 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 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 June 30,		Six months ended June 30,	
($ millions, except per share amounts)	2018	2017	2018	2017
Dividends to shareholders	$ 7.3	$ 7.3	$ 14.7	$ 14.5
Per weighted average share (Basic)	$ 0.03	$ 0.03	$ 0.06	$ 0.06

During the three and six months ended June 30, 2018, we reported total dividends of $7.3 million or $0.03 per share and $14.7 million or $0.06 per share, respectively, compared to $7.3 million or $0.03 per share and $14.5 million or $0.06 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

	Six months ended June 30,	
	2018	2017
Share capital ($ millions)	$ 3,415.0	$ 3,386.9
Common shares outstanding (thousands)	244,984	242,129
Weighted average shares outstanding – basic (thousands)	244,369	241,710
Weighted average shares outstanding – diluted (thousands)	249,367	246,566

For the six months ended June 30, 2018, a total of 315,843 shares were issued pursuant to our stock option plan resulting in additional share capital of $4.3 million, and a $0.4 million transfer from paid-in capital to share capital (2017 – nil). For the six months ended June 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). For further details, see Note 14 to the Interim Financial Statements.

At August 9, 2018, we had 245,293,306 common shares outstanding. In addition, an aggregate of 11,376,433 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.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

($ millions, except per unit amounts)	Three months ended June 30, 2018 Canada	U.S.	Total	Three months ended June 30, 2017 Canada	U.S.	Total
Average Daily Production Volumes[(1)]						
Crude oil (bbls/day)	9,212	36,030	45,242	10,853	26,008	36,861
Natural gas liquids (bbls/day)	1,055	3,753	4,808	1,199	2,934	4,133
Natural gas (Mcf/day)	29,151	227,844	256,995	46,729	224,563	271,292
Total average daily production (BOE/day)	15,126	77,757	92,883	19,840	66,369	86,209
Pricing[(2)]						
Crude oil (per bbl)	$ 66.58	$ 83.41	$ 79.98	$ 50.45	$ 57.83	$ 55.66
Natural gas liquids (per bbl)	50.20	27.18	32.23	37.35	20.14	25.14
Natural gas (per Mcf)	2.07	2.76	2.68	3.59	3.46	3.48
Capital Expenditures						
Capital spending	$ 11.4	$ 165.7	$ 177.1	$ 10.6	$ 91.1	$ 101.7
Acquisitions	1.0	1.4	2.4	1.1	3.6	4.7
Divestments	0.2	—	0.2	(59.6)	(0.2)	(59.8)
Netback[(3)] Before Hedging						
Oil and natural gas sales	$ 66.9	$ 339.9	$ 406.8	$ 69.2	$ 212.9	$ 282.1
Royalties	(10.7)	(68.7)	(79.4)	(14.3)	(42.1)	(56.4)
Production taxes	(0.7)	(21.9)	(22.6)	(0.8)	(13.0)	(13.8)
Cash operating expenses	(17.7)	(43.3)	(61.0)	(19.4)	(26.8)	(46.2)
Transportation costs	(2.8)	(27.3)	(30.1)	(3.1)	(26.1)	(29.2)
Netback before hedging	$ 35.0	$ 178.7	$ 213.7	$ 31.6	$ 104.9	$ 136.5
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 91.0	$ —	$ 91.0	$ (31.9)	$ —	$ (31.9)
General and administrative expense[(4)]	6.3	10.9	17.2	7.9	7.4	15.3
Current income tax expense/(recovery)	—	0.1	0.1	—	2.0	2.0

($ millions, except per unit amounts)	Six months ended June 30, 2018 Canada	U.S.	Total	Six months ended June 30, 2017 Canada	U.S.	Total
Average Daily Production Volumes[(1)]						
Crude oil (bbls/day)	9,362	32,002	41,364	11,875	23,155	35,030
Natural gas liquids (bbls/day)	1,151	3,298	4,449	1,301	2,347	3,648
Natural gas (Mcf/day)	31,131	228,010	259,141	57,575	223,818	281,393
Total average daily production (BOE/day)	15,701	73,302	89,003	22,772	62,805	85,577
Pricing[(2)]						
Crude oil (per bbl)	$ 59.63	$ 79.94	$ 75.34	$ 51.11	$ 59.32	$ 56.54
Natural gas liquids (per bbl)	47.46	24.39	30.36	37.21	26.88	30.57
Natural gas (per Mcf)	2.63	3.16	3.09	3.62	3.54	3.56
Capital Expenditures						
Capital spending	$ 24.6	$ 304.0	$ 328.6	$ 35.6	$ 186.5	$ 222.1
Acquisitions	2.1	12.6	14.7	2.7	4.5	7.2
Divestments	(0.7)	(6.1)	(6.8)	(58.7)	(0.2)	(58.9)
Netback[(3)] Before Hedging						
Oil and natural gas sales	$ 127.6	$ 607.7	$ 735.3	$ 156.3	$ 403.5	$ 559.8
Royalties	(20.7)	(122.2)	(142.9)	(26.2)	(80.1)	(106.3)
Production taxes	(1.5)	(37.3)	(38.8)	(1.9)	(22.3)	(24.2)
Cash operating expenses	(38.2)	(76.5)	(114.7)	(45.9)	(50.5)	(96.4)
Transportation costs	(5.8)	(51.2)	(57.0)	(7.5)	(51.3)	(58.8)
Netback before hedging	$ 61.4	$ 320.5	$ 381.9	$ 74.8	$ 199.3	$ 274.1
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 111.4	$ —	$ 111.4	$ (89.5)	$ —	$ (89.5)
General and administrative expense[(4)]	21.7	18.7	40.4	25.7	13.1	38.8
Current income tax expense/(recovery)	—	0.1	0.1	—	2.1	2.1

(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
2018				
Second Quarter	$ 327.4	$ 12.4	$ 0.05	$ 0.05
First Quarter	265.0	29.6	0.12	0.12
Total 2018	$ 592.4	$ 42.0	$ 0.17	$ 0.17
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 second quarter of 2018 compared to the first quarter of 2018 due to increased production volumes and higher realized crude oil prices. Net income decreased in the second quarter of 2018 compared to the first quarter of 2018 due to a $91.0 million loss on commodity hedges. 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 production. Net income has stabilized in 2018, after a gain was recorded on asset divestments in the second quarter of 2017 and reversal of the valuation allowance on our deferred tax asset in the fourth quarter of 2016.

U.S. Filing Status

Pursuant to U.S. securities regulations, we are required to reassess our U.S. securities filing status annually at June 30. As at June 30, 2018, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

2018 UPDATED GUIDANCE

We are increasing our average annual production guidance range to 91,000 – 93,000 BOE/day from 86,000 – 91,000 BOE/day and narrowing our average annual crude oil and natural gas liquids production range to 49,000 – 50,000 bbls/day from 46,000 – 50,000 bbls/day. We are revising our annual capital spending guidance to $585 million, from our previous guidance range of $535 – $585 million, and reducing our annual cash G&A to $1.55/BOE from $1.65/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 (from $535 – $585 million)
Average annual production	91,000 – 93,000 BOE/day (from 86,000 – 91,000 BOE/day)
Average annual crude oil and natural gas liquids production	49,000 – 50,000 bbls/day (from 46,000 – 50,000 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	$1.55/BOE (from $1.65/BOE)

2018 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	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 June 30,**		**Six months ended June 30,**	
($ millions)	**2018**	**2017**	**2018**	**2017**
Oil and natural gas sales	$ 406.8	$ 282.1	$ 735.3	$ 559.8
Less:				
Royalties	(79.4)	(56.4)	(142.9)	(106.3)
Production taxes	(22.6)	(13.8)	(38.8)	(24.2)
Cash operating expenses(1)	(61.0)	(46.2)	(114.7)	(96.4)
Transportation costs	(30.1)	(29.2)	(57.0)	(58.8)
Netback before hedging	$ 213.7	$ 136.5	$ 381.9	$ 274.1
Cash gains/(losses) on derivative instruments	(19.3)	2.2	(9.1)	8.8
Netback after hedging	$ 194.4	$ 138.7	$ 372.8	$ 282.9

(1) Total operating expenses have been adjusted to exclude a non-cash gain of $0.1 million for the three and six months ended June 30, 2018, and non-cash gains of $0.4 million and $0.3 million, respectively, in the three and six months ended June 30, 2017.

"Adjusted funds flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating 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 June 30,**		**Six months ended June 30,**	
($ millions)	**2018**	**2017**	**2018**	**2017**
Cash flow from operating activities	$ 141.8	$ 98.3	$ 301.1	$ 226.2
Asset retirement obligation expenditures	2.0	1.5	5.4	4.1
Changes in non-cash operating working capital	29.9	14.4	22.4	3.8
Adjusted funds flow	$ 173.7	$ 114.2	$ 328.9	$ 234.1

"Total debt net of cash" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. Total debt net of cash is calculated as senior notes plus 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 June 30,**		**Six months ended June 30,**	
($ millions)	**2018**	**2017**	**2018**	**2017**
Dividends	$ 7.3	$ 7.3	$ 14.7	$ 14.5
Capital and office expenditures	179.4	102.0	332.3	222.5
Sub-total	$ 186.7	$ 109.3	$ 347.0	$ 237.0
Adjusted funds flow	$ 173.7	$ 114.2	$ 328.9	$ 234.1
Adjusted payout ratio (%)	107%	96%	106%	101%

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

Reconciliation of Net Income to Adjusted EBITDA[1]

($ millions)	June 30, 2018
Net income/(loss)	$ 73.4
Add:	
Interest	36.7
Current and deferred tax expense/(recovery)	28.7
DD&A and asset impairment	262.6
Other non-cash charges[2]	204.2
Adjusted EBITDA	$ 605.6

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at June 30, 2018 include the six months ended June 30, 2018 and the third and fourth quarters 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", "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 June 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 April 1, 2018 and ended June 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 and to negotiate relief if required; 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; our ability to negotiate debt covenant relief under our bank credit facility and outstanding senior notes if required; 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$66.00/bbl, a NYMEX price of US$2.84/Mcf, and a USD/CDN exchange rate of 1.30. 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.