Exhibit 99.1

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

The following discussion and analysis of financial results is dated November 8, 2017 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, 2017 and 2016 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014; and
- our MD&A for the year ended December 31, 2016 (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 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 peers.

OVERVIEW

Production for the third quarter averaged 79,128 BOE/day, a decrease of 8% compared to the second quarter. The decrease reflects the full quarter impact of Canadian asset divestments which closed in the second quarter for 5,600 BOE/day, as well as production curtailment in the Marcellus due to weakness in regional pricing. In North Dakota, 8.6 net wells were brought on-stream late in the third quarter modestly impacting production. However, these wells are expected to support our crude oil and liquids growth in the fourth quarter. We are reaffirming our annual average crude oil and natural gas liquids guidance of 40,500 bbls/day, the mid-point of our previous guidance range of 39,500 – 41,500 bbls/day, and narrowing our fourth quarter average crude oil and natural gas liquids range to 45,000 – 46,000 bbls/day from 43,000 – 48,000 bbls/day. As a result of price-related curtailments in the Marcellus of approximately 25,000 Mcf/day in September and 35,000 Mcf/day in October, we are revising our annual average production guidance to 84,000 BOE/day, the lower end of our previous range of 84,000 – 86,000 BOE/day, and narrowing our fourth quarter 2017 average production guidance range to 86,000 – 88,000 BOE/day from 86,000 – 91,000 BOE/day.

Capital expenditures totaled $119.1 million in the third quarter, or $341.2 million year to date, with the majority of the third quarter spending directed to our North Dakota crude oil properties. We are maintaining our 2017 annual capital spending guidance of $450 million.

Operating costs for the quarter increased to $6.71/BOE from $5.83/BOE in the second quarter of 2017, mainly due to the decrease in our Marcellus natural gas production volumes which have lower associated operating costs, as well as higher gas facility charges and well servicing costs on our crude oil properties. We are increasing our annual operating cost guidance to $6.50/BOE from $6.40/BOE, primarily as a result of the Marcellus curtailment. We are also reducing our annual guidance for transportation costs to $3.70/BOE from $3.90/BOE.

Cash G&A expenses for the third quarter were $11.7 million or $1.61/BOE, in line with $12.0 million during the second quarter and an increase on a per BOE basis, due to lower production volumes. We are lowering our annual cash G&A expense guidance to $1.70/BOE from $1.75/BOE due to continued cost savings year to date.

We continued to add to our commodity hedge positions during the quarter. As of November 8, 2017, we have approximately 72% of our forecasted crude oil production, net of royalties, hedged for the remainder of 2017, and approximately 70% and 36% of our crude oil production, net of royalties, hedged in 2018 and 2019, respectively, based on 2017 forecasted production. We have also hedged approximately 25% of our forecasted natural gas production, net of royalties, for the remainder of 2017 and approximately 13% of our natural gas production, net of royalties, for 2018 based on 2017 forecasted production.

We recorded net income of $16.1 million and adjusted funds flow of $90.4 million in the third quarter, compared to $129.3 million and $114.2 million, respectively, in the second quarter of 2017. Net income and funds flow decreased from the second quarter with lower realized commodity prices and lower production volumes. Net income in the second quarter of 2017 also included a gain of $78.4 million on the divestment of certain Canadian properties.

At September 30, 2017, our total debt net of cash was $318.3 million and our net debt to adjusted funds flow ratio was 0.7x. Subsequent to the quarter end, we completed a one year extension of our senior, unsecured, covenant-based bank credit facility, which now matures on October 31, 2020.

RESULTS OF OPERATIONS

Production

Production in the third quarter of 2017 decreased 14% to 79,128 BOE/day from average production levels of 92,077 BOE/day during the same period in 2016, due to the sale of non-core properties from the fourth quarter of 2016 through the second quarter of 2017 with associated production of approximately 12,300 BOE/day. This decrease was somewhat offset by our November 2016 Canadian waterflood acquisition and increased capital spending commencing in January of 2017 to reinitiate growth on our North Dakota Bakken asset.

Our crude oil and natural gas liquids weighting increased during the third quarter to 49% from 48% in the second quarter of 2017 and from 46% for the three months ended September 30, 2016.

Average daily production volumes for the three and nine months ended September 30, 2017 and 2016 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2017**	**2016**	**% Change**	**2017**	**2016**	**% Change**
Crude oil (bbls/day)	35,245	37,717	(7%)	35,102	38,764	(9%)
Natural gas liquids (bbls/day)	3,681	4,881	(25%)	3,659	5,067	(28%)
Natural gas (Mcf/day)	241,212	296,876	(19%)	267,852	304,150	(12%)
Total daily sales (BOE/day)	79,128	92,077	(14%)	83,403	94,523	(12%)

We are on track to meet our crude oil and natural gas liquids guidance ranges annually and for the fourth quarter. We are reaffirming the mid-point of our annual average liquids guidance at 40,500 to bbls/day and narrowing our fourth quarter average crude oil and natural gas liquids range to 45,000 – 46,000 bbls/day from 43,000 – 48,000 bbls/day. As a result of price-related curtailment in the Marcellus of approximately 25,000 Mcf/day in September and 35,000 Mcf/day in October, we are revising our annual average production guidance to 84,000 BOE/day, the lower end of our previous range of 84,000 – 86,000 BOE/day, and narrowing our fourth quarter average production guidance target to 86,000 – 88,000 BOE/day from 86,000 – 91,000 BOE/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 average prices for the nine months ended September 30, 2017 and 2016 and quarterly average prices for the periods indicated:

	Nine months ended September 30,						
Pricing (average for the period)	**2017**	**2016**	**Q3 2017**	**Q2 2017**	**Q1 2017**	**Q4 2016**	**Q3 2016**
Benchmarks							
WTI crude oil (US$/bbl)	$ 49.47	$ 41.33	$ 48.20	$ 48.29	$ 51.92	$ 49.29	$ 44.94
AECO natural gas – monthly index ($/Mcf)	2.58	1.85	2.04	2.77	2.94	2.81	2.20
AECO natural gas – daily index ($/Mcf)	2.31	1.85	1.45	2.78	2.69	3.09	2.32
NYMEX natural gas – last day (US$/Mcf)	3.17	2.29	3.00	3.18	3.32	2.98	2.81
USD/CDN average exchange rate	1.31	1.32	1.25	1.34	1.32	1.33	1.31
USD/CDN period end exchange rate	1.25	1.31	1.25	1.30	1.33	1.34	1.31
Enerplus selling price[1]							
Crude oil ($/bbl)	$ 55.75	$ 41.92	$ 54.21	$ 55.66	$ 57.53	$ 53.91	$ 47.93
Natural gas liquids ($/bbl)	29.09	13.53	26.22	25.14	37.76	21.31	13.85
Natural gas ($/Mcf)	3.26	1.79	2.58	3.48	3.63	2.89	2.12
Average differentials							
MSW Edmonton – WTI (US$/bbl)	$ (2.90)	$ (3.24)	$ (2.89)	$ (2.26)	$ (3.54)	$ (3.11)	$ (2.96)
WCS Hardisty – WTI (US$/bbl)	(11.88)	(13.68)	(9.94)	(11.13)	(14.58)	(14.32)	(13.50)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.84)	(1.01)	(1.29)	(0.60)	(0.63)	(1.58)	(1.35)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.91)	(1.07)	(1.36)	(0.66)	(0.70)	(1.64)	(1.40)
AECO monthly – NYMEX (US$/Mcf)	(1.21)	(0.89)	(1.39)	(1.13)	(1.10)	(0.86)	(1.13)
Enerplus realized differentials [1][2]							
Canada crude oil – WTI (US$/bbl)	$ (11.09)	$ (13.17)	$ (9.29)	$ (11.02)	$ (12.76)	$ (12.97)	$ (12.06)
Canada natural gas – NYMEX (US$/Mcf)	(0.63)	(0.81)	(1.00)	(0.51)	(0.56)	(0.63)	(0.92)
Bakken crude oil – WTI (US$/bbl)	(4.69)	(7.63)	(3.24)	(5.43)	(5.59)	(6.80)	(6.39)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.75)	(0.94)	(1.02)	(0.64)	(0.60)	(0.88)	(1.19)

(1) Excluding transportation costs, royalties and 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 decreased by 3% during the quarter to average $54.21/bbl. The strengthening of the Canadian dollar largely offset the improvement in realized crude oil differentials from the second quarter, with WTI prices essentially unchanged.

Bakken price differentials to WTI improved by US$2.19/bbl during the quarter to average US$3.24/bbl below WTI. Spot Bakken prices strengthened considerably throughout the quarter due to the improved egress capacity out of the basin, on-going Canadian synthetic crude oil supply outages, and incremental demand from refineries for light barrels due to on-going market disruption during an active hurricane season. Accordingly, we are narrowing our expected realized Bakken differential to US$2.00/bbl below WTI for the remainder of 2017, and expect the differential to average US$4.00/bbl below WTI for the full year.

Our realized price differential for our Canadian crude oil production improved by 16% compared to the previous quarter, due largely to strength in Canadian heavy crude oil benchmark prices which were impacted by ongoing regional oil sands production outages. Our realized price for natural gas liquids averaged $26.22/bbl during the period, an increase of 4% compared to the previous quarter. Natural gas liquids prices strengthened during the third quarter primarily due to improved propane market fundamentals.

NATURAL GAS

Our average realized natural gas price during the third quarter decreased by 26% compared to the second quarter to average $2.58/Mcf. Benchmark NYMEX natural gas prices decreased by 6% during the quarter. Both AECO and Marcellus prices decreased more than the NYMEX benchmark due to considerable weakness in their respective basis markets.

Our realized Marcellus sales price differential, excluding transportation and gathering, widened during the quarter to average US$1.02/Mcf below NYMEX. This outperformed the Benchmark monthly Transco Leidy price which averaged US$1.29/Mcf below NYMEX during the third quarter. Marcellus pricing weakened during the quarter due to cooler than average weather in the northeast United States, and incremental supply coming onstream during the quarter in expectation of flowing on the subsequently delayed Rover pipeline. Rover capacity is being brought online in stages throughout the fall of 2017, with full capacity not expected to be in service until the end of the first quarter of 2018. We expect Marcellus differentials to average US$1.05/Mcf below NYMEX for the remainder of 2017, and to average US$0.80/Mcf below NYMEX for the full year.

AECO gas prices have been extremely weak, particularly in the day markets, due to delivery restrictions on export pipelines. In the third quarter, our realized Canadian natural gas sales differential averaged US$1.00/Mcf below NYMEX. Enerplus continues to benefit from the active management of our AECO basis risk where we have sold the majority of our Canadian production under multi-year fixed AECO basis differential contracts at prices higher than those currently realized in the spot market.

FOREIGN EXCHANGE

The Canadian dollar strengthened considerably during the third quarter to average 1.25 USD/CDN compared to average rates of 1.34 USD/CDN during the second quarter of 2017 and 1.31 USD/CDN during the third quarter of 2016. The majority of our oil and natural gas sales are based on U.S. dollar denominated indices, and a stronger Canadian dollar relative to the U.S. dollar decreases the amount of our realized sales. Because we report in Canadian dollars, the fluctuations in the Canadian dollar also impact our U.S. dollar denominated costs, capital spending and the reported value of our U.S. dollar denominated debt.

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 November 8, 2017, we have hedged 20,000 bbls/day of our expected crude oil production for the remainder of 2017, which represents approximately 72% of our 2017 forecasted crude oil production, after royalties. For 2018, we have hedged approximately 19,500 bbls/day, which represents approximately 70% of our 2017 forecasted crude oil production, after royalties. For 2019, we have hedged 10,000 bbls/day, which represents approximately 36% of our 2017 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 November 8, 2017, we have hedged 50,000 Mcf/day of our forecasted natural gas production for the remainder of 2017. This represents approximately 25% of our forecasted natural gas production, after royalties. For 2018 we have hedged 25,000 Mcf/day, which represents 13% of our 2017 forecasted natural gas production, after royalties.

The following is a summary of our financial contracts in place at November 8, 2017, expressed as a percentage of our forecasted 2017 net production volumes:

	WTI Crude Oil (US$/bbl)[1]							NYMEX Natural Gas (US$/Mcf)[1]	
	Oct 1, 2017 – Dec 31, 2017	**Jan 1, 2018 – Mar 31, 2018**	**Apr 1, 2018 – Jun 30, 2018**	**Jul 1, 2018 – Sep 30, 2018**	**Oct 1, 2018 – Dec 31, 2018**	**Jan 1, 2019 – Mar 31, 2019**	**Apr 1, 2019 – Dec 31, 2019**	**Oct 1, 2017 – Dec 31, 2017**	**Jan 1, 2018 – Dec 31, 2018**
Swaps									
Sold Swaps	$ 53.50	$ 53.73	$ 53.73	$ 53.73	$ 53.73	$ 53.73	—	—	—
%	7%	11%	11%	11%	11%	11%	—	—	—
Three Way Collars									
Sold Puts	$ 39.62	$ 42.83	$ 42.92	$ 42.71	$ 42.74	$ 43.54	$ 43.48	$ 2.06	—
%	65%	47%	54%	65%	72%	25%	36%	25%	—
Purchased Puts	$ 50.61	$ 53.04	$ 52.90	$ 52.53	$ 52.48	$ 53.21	$ 53.53	$ 2.75	$ 2.75
%	65%	47%	54%	65%	72%	25%	36%	25%	13%
Sold Calls	$ 60.33	$ 61.99	$ 61.73	$ 61.22	$ 61.10	$ 61.14	$ 62.27	$ 3.41	$ 3.46
%	65%	47%	54%	65%	72%	25%	36%	25%	13%

(1) Based on weighted average price (before premiums) assuming average annual production of 84,000 BOE/day less royalties and production taxes of 24%. A portion of the sold puts are settled annually rather than monthly.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses) ($ millions)	**Three months ended September 30,** 2017	2016	**Nine months ended September 30,** 2017	2016
Cash gains/(losses):				
Crude oil	$ 2.9	$ 11.1	$ 4.2	$ 64.0
Natural gas	—	(1.1)	7.5	7.1
Total cash gains/(losses)	$ 2.9	$ 10.0	$ 11.7	$ 71.1
Non-cash gains/(losses):				
Crude oil	$ (37.4)	$ (1.7)	$ 34.2	$ (60.1)
Natural gas	0.3	3.8	9.4	(7.4)
Total non-cash gains/(losses)	$ (37.1)	$ 2.1	$ 43.6	$ (67.5)
Total gains/(losses)	$ (34.2)	$ 12.1	$ 55.3	$ 3.6

(Per BOE)	**Three months ended September 30,** 2017	2016	**Nine months ended September 30,** 2017	2016
Total cash gains/(losses)	$ 0.40	$ 1.17	$ 0.51	$ 2.75
Total non-cash gains/(losses)	(5.10)	0.25	1.91	(2.61)
Total gains/(losses)	$ (4.70)	$ 1.42	$ 2.42	$ 0.14

During the third quarter of 2017 we realized cash gains of $2.9 million on our crude oil contracts. In comparison, during the third quarter of 2016 we realized cash gains of $11.1 million on our crude oil contracts and cash losses of $1.1 million on our natural gas contracts. The cash gains recorded in the quarter were due to crude oil contracts which provided floor protection above market prices.

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 2017, the fair value of our crude oil contracts was in a net asset position of $5.3 million, while the fair value of our natural gas contracts was in a net liability position of $0.1 million. For the three and nine months ended September 30, 2017, the change in the fair value of our crude oil contracts represented losses of $37.4 million and gains of $34.2 million, respectively, and our natural gas contracts represented gains of $0.3 million and $9.4 million, respectively.

Revenues

($ millions)	**Three months ended September 30,** 2017	2016	**Nine months ended September 30,** 2017	2016
Oil and natural gas sales	$ 241.9	$ 230.4	$ 801.7	$ 613.6
Royalties	(45.8)	(42.1)	(152.1)	(108.3)
Oil and natural gas sales, net of royalties	$ 196.1	$ 188.3	$ 649.6	$ 505.3

Oil and natural gas sales for the three and nine months ended September 30, 2017 were $241.9 million and $801.7 million, respectively, an increase of 5% and 31% from the same periods in 2016. The increase in revenue primarily resulted from higher commodity prices for both crude oil and natural gas compared to the same periods in 2016, which more than offset the impact of lower production volumes driven by asset divestments.

Royalties and Production Taxes

($ millions, except per BOE amounts)	**Three months ended September 30,** 2017	2016	**Nine months ended September 30,** 2017	2016
Royalties	$ 45.8	$ 42.1	$ 152.1	$ 108.3
Per BOE	$ 6.29	$ 4.97	$ 6.68	$ 4.18
Production taxes	$ 12.3	$ 10.4	$ 36.5	$ 26.4
Per BOE	$ 1.69	$ 1.23	$ 1.60	$ 1.02
Royalties and production taxes	$ 58.1	$ 52.5	$ 188.6	$ 134.7
Per BOE	$ 7.98	$ 6.20	$ 8.28	$ 5.20
Royalties and production taxes (% of oil and natural gas sales)	24%	23%	24%	22%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. 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 nine months ended September 30, 2017, royalties and production taxes increased to $58.1 million and $188.6 million, respectively, from $52.5 million and $134.7 million for the same periods in 2016 primarily due to higher commodity prices and a greater weighting of our production coming from our U.S. properties which have a combined royalty and production tax rate of approximately 25%. Royalties and production taxes averaged 24% of crude oil and natural gas sales before transportation in the first nine months of 2017 compared to 22% for the same period in 2016.

We are maintaining our annual average royalty and production tax rate guidance of 24% for 2017.

Operating Expenses

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	**2017**	**2016**	**2017**	**2016**
Cash operating expenses	$ 48.9	$ 56.2	$ 145.4	$ 189.9
Non-cash (gains)/losses(1)	(0.1)	—	(0.4)	(0.5)
Total operating expenses	$ 48.8	$ 56.2	$ 145.0	$ 189.4
Per BOE	$ 6.71	$ 6.64	$ 6.37	$ 7.31

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

For the three and nine months ended September 30, 2017, operating expenses were $48.8 million or $6.71/BOE and $145.0 million or $6.37/BOE, respectively, compared to our annual guidance of $6.40/BOE. Operating costs were lower by $7.4 million and $44.4 million, respectively, compared to the same periods in 2016 mainly due to the divestment of higher operating cost Canadian properties throughout 2016 and into 2017 along with cost savings initiatives. On a per BOE basis, operating costs for the nine months ended September 30, 2017 were 13% lower compared to the same period in 2016. However on a per BOE basis, the third quarter of 2017 increased slightly due to a decrease in Marcellus natural gas production volumes which have lower associated operating costs, as well as higher gas facility charges and well servicing costs on our crude oil properties.

We are increasing our annual operating cost guidance to $6.50/BOE from $6.40/BOE, primarily due to the impact of the Marcellus curtailment in September and October.

Transportation Costs

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	**2017**	**2016**	**2017**	**2016**
Transportation costs	$ 26.3	$ 28.8	$ 85.1	$ 78.9
Per BOE	$ 3.61	$ 3.39	$ 3.74	$ 3.05

For the three and nine months ended September 30, 2017, transportation costs were $26.3 million or $3.61/BOE and $85.1 million or $3.74/BOE, respectively, relative to our annual guidance target of $3.90/BOE. During the same periods in 2016 transportation costs were $28.8 million or $3.39/BOE and $78.9 million or $3.05/BOE, respectively. The increase in the cost per BOE is primarily due to additional firm transportation commitments, including 30,000 Mcf/day of additional interstate pipeline capacity from the Marcellus region to downstream connections that came into effect in August 2016, and a higher proportion of total production volumes from the U.S. which have higher associated transportation costs.

We are revising our annual guidance for transportation costs to $3.70/BOE from $3.90/BOE due to the impact of the Marcellus curtailment, the lower USD/CDN foreign exchange rates on U.S. transportation costs, and increased North Dakota production sold on a netback basis.

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, 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 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	Three months ended September 30, 2016 Crude Oil	Natural Gas	Total
Average Daily Production	46,471 BOE/day	273,636 Mcfe/day	92,077 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 40.69	$ 2.24	$ 27.20
Royalties and production taxes	(10.22)	(0.35)	(6.20)
Cash operating expenses	(10.29)	(0.48)	(6.64)
Transportation costs	(2.20)	(0.77)	(3.39)
Netback before hedging	$ 17.98	$ 0.64	$ 10.97
Cash gains/(losses)	2.59	(0.04)	1.17
Netback after hedging	$ 20.57	$ 0.60	$ 12.14
Netback before hedging ($ millions)	$ 76.9	$ 16.0	$ 92.9
Netback after hedging ($ millions)	$ 88.0	$ 14.9	$ 102.9

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 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

Netbacks by Property Type	Nine months ended September 30, 2016 Crude Oil	Natural Gas	Total
Average Daily Production	47,403 BOE/day	282,720 Mcfe/day	94,523 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 36.07	$ 1.87	$ 23.69
Royalties and production taxes	(8.55)	(0.30)	(5.20)
Cash operating expenses	(10.27)	(0.73)	(7.33)
Transportation costs	(1.96)	(0.69)	(3.05)
Netback before hedging	$ 15.29	$ 0.15	$ 8.11
Cash gains/(losses)	4.93	0.09	2.75
Netback after hedging	$ 20.22	$ 0.24	$ 10.86
Netback before hedging ($ millions)	$ 198.6	$ 11.5	$ 210.1
Netback after hedging ($ millions)	$ 262.6	$ 18.6	$ 281.2

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

Crude oil and natural gas netbacks per BOE were higher for both the three and nine months ended September 30, 2017 compared to the same periods in 2016 due to higher oil and natural gas prices, improvements in the sales price differentials in the North Dakota and Marcellus regions, along with reductions to our operating expenses due in part to the sale of non-core

Canadian assets. For the three and nine month periods ended September 30, 2017, our crude oil properties accounted for 85% and 75%, respectively, of our netback before hedging, compared to 83% and 95% of our netback during the same periods in 2016.

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)	2017	2016	2017	2016
Cash:				
G&A expense	$ 11.7	$ 13.4	$ 37.9	$ 46.4
Share-based compensation expense	0.7	0.2	0.9	1.8
Non-Cash:				
Share-based compensation expense	4.1	2.9	15.6	11.7
Equity swap loss/(gain)	(0.8)	0.1	0.2	(1.6)
Total G&A expenses	$ 15.7	$ 16.6	$ 54.6	$ 58.3

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2017	2016	2017	2016
Cash:				
G&A expense	$ 1.61	$ 1.58	$ 1.67	$ 1.79
Share-based compensation expense	0.10	0.03	0.04	0.07
Non-Cash:				
Share-based compensation expense	0.57	0.35	0.69	0.45
Equity swap loss/(gain)	(0.11)	0.01	0.01	(0.06)
Total G&A expenses	$ 2.17	$ 1.97	$ 2.41	$ 2.25

For the three and nine months ended September 30, 2017 cash G&A expenses were $11.7 million or $1.61/BOE and $37.9 million or $1.67/BOE, respectively, compared to $13.4 million or $1.58/BOE and $46.4 million or $1.79/BOE for the same periods in 2016. The decrease in cash G&A expenses from the prior year was primarily due to continued cost savings initiatives and the impact of reductions in staff levels throughout 2016 and early 2017 as we continue to focus our business through asset divestments.

During the quarter, we reported cash SBC expense of $0.7 million due to our share price improvement. In comparison, during the same period of 2016, we recorded cash SBC expense of $0.2 million. We recorded non-cash SBC of $4.1 million or $0.57/BOE in the third quarter of 2017 compared to $2.9 million or $0.35/BOE during the same period in 2016. The increase in non-cash SBC was a result of an improvement in our performance multiplier based on our relative return in the Toronto Stock Exchange Oil and Gas Producers Index, which was partially offset by the impact of forfeitures due to reductions in staff over the past year.

We are reducing our annual cash G&A guidance to $1.70/BOE from $1.75/BOE due to further cost reductions.

Interest Expense

For the three and nine months ended September 30, 2017, we recorded total interest expense of $8.7 million and $29.0 million, respectively, compared to $9.7 million and $34.3 million for the same periods in 2016. The decrease in interest expense for the three month period was primarily due to the impact of a strengthening Canadian dollar on our U.S. dollar denominated interest expense, along with the payment of our first installment of US$22 million on our US$110 million senior notes during the second quarter of 2017. The decrease for the nine month period ended September 30, 2017 compared to the same period in 2016, was primarily due to the repurchase of US$267 million of senior notes during the first half of 2016.

At September 30, 2017, we were undrawn on our $800 million bank credit facility and our debt balance consisted of fixed interest rate senior notes with a weighted average interest rate of 4.8%. See Note 8 in the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended September 30, 2017	2016	Nine months ended September 30, 2017	2016
Realized:				
Foreign exchange (gain)/loss on settlements	$ 0.5	$ (0.9)	$ 1.5	$ 1.1
Translation of U.S. dollar cash held in Canada (gain)/loss	13.5	—	13.5	—
Unrealized (gain)/loss	(31.6)	4.0	(48.6)	(52.0)
Total foreign exchange (gain)/loss	$ (17.6)	$ 3.1	$ (33.6)	$ (50.9)
USD/CDN average exchange rate	1.25	1.31	1.31	1.32
USD/CDN period end exchange rate	1.25	1.31	1.25	1.31

For the three and nine months ended September 30, 2017, we recorded net foreign exchange gains of $17.6 million and $33.6 million, respectively, compared to a loss of $3.1 million and a gain of $50.9 million for the same periods in 2016. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies, along with the translation of our U.S. dollar denominated cash held in Canada, while unrealized gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. When comparing September 30, 2017 to December 31, 2016, the Canadian dollar strengthened relative to the U.S. dollar resulting in unrealized gains of $48.6 million. See Note 12 to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended September 30, 2017	2016	Nine months ended September 30, 2017	2016
Capital spending	$ 119.1	$ 60.3	$ 341.2	$ 151.7
Office capital	0.5	0.6	1.0	0.7
Sub-total	119.6	60.9	342.2	152.4
Property and land acquisitions	$ 2.2	$ 3.8	$ 9.5	$ 7.7
Property divestments	1.4	(0.1)	(57.6)	(280.6)
Sub-total	3.6	3.7	(48.1)	(272.9)
Total	$ 123.2	$ 64.6	$ 294.1	$ (120.5)

Capital spending for the three and nine months ended September 30, 2017, totaled $119.1 million and $341.2 million, respectively, compared to the $60.3 million and $151.7 million for the same periods in 2016. The increased spending is in line with our strategy to re-initiate growth through an increased capital program in 2017. During the quarter we spent $92.4 million on our U.S. crude oil properties, $16.0 million on our Marcellus natural gas assets and $9.2 million on our Canadian waterflood properties.

Property divestments for the nine months ended September 30, 2017 were $57.6 million, consisting mainly of our second quarter divestment of our Brooks waterflood property and Canadian shallow gas assets. In comparison, we had divestments of $280.6 million during the same period in 2016, which was mainly related to the divestment of non-core properties in the Deep Basin and in N.W. Alberta.

We continue to expect annual capital spending of $450 million.

Gain on Asset Sales and Note Repurchases

We recorded a gain of $78.4 million on the sale of Canadian properties for the first nine months of 2017. In comparison, gains of $219.8 million were recorded on asset divestments during the first nine months of 2016. Under full cost accounting rules, divestments of oil and natural gas properties are generally accounted for as adjustments to the full cost pool with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would significantly alter the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized. Gains and losses are evaluated on a case by case basis for each asset sale, and future sales may or may not result in such treatment.

For the nine month period ended September 30, 2016, we recorded gains of $19.3 million on the repurchase of US$267 million of our senior notes at a discount to par value.

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

($ millions, except per BOE amounts)	Three months ended September 30, 2017	2016	Nine months ended September 30, 2017	2016
DD&A expense	$ 59.8	$ 91.8	$ 185.1	$ 266.0
Per BOE	$ 8.21	$ 10.83	$ 8.13	$ 10.27

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three and nine months ended September 30, 2017, DD&A decreased when compared to the same period of 2016 primarily due to the cumulative effects of asset impairments recorded during 2016 as well as lower overall production with asset divestments.

Impairment

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

The trailing-twelve-month average crude oil and natural gas prices increased during the first nine months of 2017 compared to a decrease during the same period in 2016. There were no impairments recorded for the three and nine months ended September 30, 2017, compared to $61.0 million and $255.8 million, respectively, recognized in the same periods of 2016.

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the amount of impairment losses from future ceiling tests. The primary factors include future first-day-of-the-month commodity prices, reserves revisions, our capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. Furthermore, there is the potential for prices to decline from current levels, which would impact the ceiling value and could result in non-cash impairments. See Note 6 to the Interim Financial Statements for trailing twelve month prices.

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 cost to be incurred in future periods. We have estimated the net present value of our asset retirement obligation to be $105.5 million at September 30, 2017, compared to $181.7 million at December 31, 2016. For the three and nine months ended September 30, 2017, asset retirement obligation settlements were $3.1 million and $7.1 million, respectively, compared to $1.2 million and $4.4 million during the same periods in 2016. As a result of our divestments to date in 2017, we have reduced our asset retirement obligation by $72.1 million or 40%. See Note 9 to the Interim Financial Statements for further details.

Income Taxes

($ millions)	Three months ended September 30, 2017	2016	Nine months ended September 30, 2017	2016
Current tax expense/(recovery)	$ 0.1	$ 0.1	$ 2.2	$ (0.3)
Deferred tax expenses/(recovery)	(7.7)	23.2	59.4	333.0
Total tax expense/(recovery)	$ (7.6)	$ 23.3	$ 61.6	$ 332.7

For the three and nine months ended September 30, 2017, we recorded total tax recovery of $7.6 million and an expense of $61.6 million, respectively, compared to total tax expense of $23.3 million and $332.7 million for the same periods in 2016.

The overall tax expense was lower for the three and nine months ended September 30, 2017, primarily due to an increase in our valuation allowance in both Canada and the U.S. in 2016. We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not that all or a portion of our deferred income tax assets will be realized. Our overall net deferred income tax asset was $636.7 million at September 30, 2017 (December 31, 2016 - $733.4 million).

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 September 30, 2017, our senior debt to adjusted EBITDA ratio was 0.8x and our net debt to adjusted funds flow ratio was 0.7x. 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, 2017 was $318.3 million, a decrease of 15% compared to $375.5 million at December 31, 2016. Total debt was comprised of $667.3 million of senior notes less $349.0 million in cash. At September 30, 2017, we were fully 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 140% and 112% for the three and nine months ended September 30, 2017, respectively, compared to 85% and 91% for the same periods in 2016. After adjusting for net divestments of $48.1 million, we had a funding surplus of $8.6 million for the nine months ended September 30, 2017.

Our working capital deficiency, excluding cash, restricted cash and current deferred financial assets and liabilities, increased to $122.9 million at September 30, 2017 from $94.4 million at December 31, 2016. 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, 2020. There were no other amendments to the agreement terms or covenants. Drawn fees on the facility range between 150 and 315 basis points over Banker's Acceptance rates, with current drawn fees of 150 basis points over Banker's Acceptance rates based on our last reported senior debt to adjusted EBITDA ratio. The bank credit facility ranks equally with our senior, unsecured covenant-based notes.

At September 30, 2017, 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 as material documents on our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at September 30, 2017:

Covenant Description		September 30, 2017
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA [(1)]	3.5x	0.8x
Total debt to adjusted EBITDA	4.0x	0.8x
Total debt to capitalization	50%	21%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA [(2)]	3.0x - 3.5x	0.8x
Senior debt to consolidated present value of total proved reserves[(3)]	60%	25%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	21.3x

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, 2017 was $85.6 million and $857.4 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 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

($ millions, except per share amounts)	Three months ended September 30, 2017	2016	Nine months ended September 30, 2017	2016
Dividends to shareholders	$ 7.3	$ 7.2	$ 21.8	$ 28.2
Per weighted average share (Basic)	$ 0.03	$ 0.03	$ 0.09	$ 0.13

During the three and nine months ended September 30, 2017, we reported total dividends of $7.3 million or $0.03 per share and $21.8 million or $0.09 per share, respectively, compared to $7.2 million or $0.03 per share and $28.2 million or $0.13 per share for the same periods in 2016. Effective with our April 2016 payment, we reduced our monthly dividend from $0.03 per share to $0.01 per share to provide additional financial flexibility and balance adjusted funds flow with capital and dividends.

The dividend is part of our strategy to create shareholder value; however, a sustained low price environment may impact our ability to pay dividends. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Nine months ended September 30, 2017	2016
Share capital ($ millions)	$ 3,386.9	$ 3,366.0
Common shares outstanding (thousands)	242,129	240,483
Weighted average shares outstanding – basic (thousands)	241,854	221,843
Weighted average shares outstanding – diluted (thousands)	247,306	221,843

During the third quarter, no shares were issued pursuant to our LTI plans, resulting in no additional equity being recorded during the period (2016 – nil). For the nine months ended September 30, 2017 a total of 1,646,000 shares were issued pursuant to our LTI plans and accordingly, $21.0 million was transferred from paid-in capital to share capital (2016 – 594,000; $9.4 million). For further details, see Note 14 to the Interim Financial Statements.

On May 31, 2016, 33,350,000 common shares were issued at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million net of issue costs, before tax).

At November 8, 2017, we had 242,128,944 common shares outstanding. In addition, an aggregate of 13,033,023 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

	Three months ended September 30, 2017			Three months ended September 30, 2016		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	9,924	25,321	35,245	12,273	25,444	37,717
Natural gas liquids (bbls/day)	975	2,706	3,681	1,254	3,627	4,881
Natural gas (Mcf/day)	32,864	208,348	241,212	68,605	228,271	296,876
Total average daily production (BOE/day)	16,376	62,752	79,128	24,961	67,116	92,077
Pricing(2)						
Crude oil (per bbl)	$ 48.68	$ 56.38	$ 54.21	$ 42.92	$ 50.35	$ 47.93
Natural gas liquids (per bbl)	33.23	23.69	26.22	25.67	9.77	13.85
Natural gas (per Mcf)	2.50	2.59	2.58	2.47	2.01	2.12
Capital Expenditures						
Capital spending	$ 10.0	$ 109.1	$ 119.1	$ 8.0	$ 52.3	$ 60.3
Acquisitions	0.8	1.4	2.2	1.2	2.6	3.8
Divestments	1.3	0.1	1.4	—	(0.1)	(0.1)
Netback(3) **Before Hedging**						
Oil and natural gas sales	$ 55.0	$ 186.9	$ 241.9	$ 67.0	$ 163.4	$ 230.4
Royalties	(9.2)	(36.6)	(45.8)	(9.6)	(32.5)	(42.1)
Production taxes	(0.7)	(11.6)	(12.3)	(1.2)	(9.2)	(10.4)
Cash operating expenses	(18.0)	(30.9)	(48.9)	(30.1)	(26.1)	(56.2)
Transportation costs	(2.9)	(23.4)	(26.3)	(3.3)	(25.5)	(28.8)
Netback before hedging	$ 24.2	$ 84.4	$ 108.6	$ 22.8	$ 70.1	$ 92.9
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 34.2	$ —	$ 34.2	$ (12.1)	$ —	$ (12.1)
General and administrative expense(4)	9.2	6.5	15.7	9.8	6.8	16.6
Current income tax expense/(recovery)	(0.4)	0.5	0.1	—	0.1	0.1

	Nine months ended September 30, 2017			Nine months ended September 30, 2016		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	11,217	23,885	35,102	13,315	25,449	38,764
Natural gas liquids (bbls/day)	1,191	2,468	3,659	1,491	3,576	5,067
Natural gas (Mcf/day)	49,247	218,605	267,852	82,623	221,527	304,150
Total average daily production (BOE/day)	20,616	62,787	83,403	28,577	65,946	94,523
Pricing(2)						
Crude oil (per bbl)	$ 50.39	$ 58.27	$ 55.75	$ 37.24	$ 44.36	$ 41.92
Natural gas liquids (per bbl)	36.12	25.70	29.09	25.22	8.65	13.53
Natural gas (per Mcf)	3.37	3.24	3.26	1.94	1.74	1.79
Capital Expenditures						
Capital spending	$ 45.6	$ 295.6	$ 341.2	$ 34.2	$ 117.5	$ 151.7
Acquisitions	3.5	6.0	9.5	3.2	4.5	7.7
Divestments	(57.5)	(0.1)	(57.6)	(279.5)	(1.1)	(280.6)
Netback(3) **Before Hedging**						
Oil and natural gas sales	$ 211.4	$ 590.3	$ 801.7	$ 190.3	$ 423.3	$ 613.6
Royalties	(35.4)	(116.7)	(152.1)	(24.8)	(83.5)	(108.3)
Production taxes	(2.6)	(33.9)	(36.5)	(2.1)	(24.3)	(26.4)
Cash operating expenses	(63.9)	(81.5)	(145.4)	(105.0)	(84.9)	(189.9)
Transportation costs	(10.4)	(74.7)	(85.1)	(10.8)	(68.1)	(78.9)
Netback before hedging	$ 99.1	$ 283.5	$ 382.6	$ 47.6	$ 162.5	$ 210.1
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (55.3)	$ —	$ (55.3)	$ (3.6)	$ —	$ (3.6)
General and administrative expense(4)	35.0	19.6	54.6	42.9	15.4	58.3
Current income tax expense/(recovery)	(0.4)	2.6	2.2	(0.7)	0.4	(0.3)

(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.

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
2017				
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	$ 649.6	$ 221.7	$ 0.92	$ 0.90
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
2015				
Fourth Quarter	$ 199.4	$ (625.0)	$ (3.03)	$ (3.03)
Third Quarter	228.3	(292.7)	(1.42)	(1.42)
Second Quarter	251.7	(312.5)	(1.52)	(1.52)
First Quarter	205.0	(293.2)	(1.42)	(1.42)
Total 2015	$ 884.4	$ (1,523.4)	$ (7.39)	$ (7.39)

Oil and natural gas sales, net of royalties, decreased in the third quarter compared to the second quarter of 2017 due to lower realized crude oil and natural gas prices and decreased production volumes. Net income also decreased from the third quarter compared to the second quarter due to the decrease in oil and natural gas sales, as well as a gain of $78.4 million recorded on the divestment of certain Canadian properties in the second quarter. Oil and natural gas sales, net of royalties, decreased throughout 2015 and 2016 as commodity prices declined. During 2015, the impact of weak commodity prices was somewhat offset by increasing production. Net losses reported in 2015 and 2016 were primarily due to non-cash asset impairments and valuation allowances on our deferred tax asset related to the decrease in the trailing twelve-month average commodity prices, along with reduced revenues. Net income in the fourth quarter of 2016 related primarily to the reversal of the valuation allowance on our deferred tax asset.

2017 UPDATED GUIDANCE

We are reaffirming our annual average crude oil and natural gas liquids production at 40,500 bbls/day, the mid-point of our previous guidance range, and are narrowing our fourth quarter average crude oil and natural gas liquids production range to 45,000 – 46,000 bbls/day from 43,000 – 48,000 bbls/day. We are revising our annual average production guidance to 84,000 BOE/day, the lower end of our previous range of 84,000 – 86,000 BOE/day, and narrowing our fourth quarter average production guidance range to 86,000 – 88,000 BOE/day from 86,000 – 91,000 BOE/day. We are reducing our cash G&A expense guidance to $1.70/BOE from $1.75/BOE and our transportation cost guidance to $3.70/BOE from $3.90/BOE. We are increasing our operating cost guidance to $6.50/BOE from $6.40/BOE. We are revising our expected Bakken differential to average US$2.00/bbl below WTI for the fourth quarter and US$4.00/bbl below WTI for the full year of 2017, and have revised our expected Marcellus differential to average US$1.05/Mcf below NYMEX for the fourth quarter and US$0.80/Mcf below NYMEX for the full year of 2017.

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

Summary of 2017 Expectations	Target
Capital spending	$450 million
Average annual production	84,000 BOE/day (from 84,000 - 86,000 BOE/day)
Fourth quarter average production	86,000 – 88,000 BOE/day (from 86,000 – 91,000 BOE/day)
Average annual crude oil and natural gas liquids production	40,500 bbls/day (from 39,500 – 41,500 bbls/day)
Fourth quarter average annual crude oil and natural gas liquids production	45,000 - 46,000 bbls/day (from 43,000 – 48,000 bbls/day)
Average royalty and production tax rate (% of gross sales, before transportation)	24%
Operating expenses	$6.50/BOE (from $6.40/BOE)
Transportation costs	$3.70/BOE (from $3.90/BOE)
Cash G&A expenses	$1.70/BOE (from $1.75/BOE)

2017 Differential/Basis Outlook[1]	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(4.00)/bbl (from US$(4.50)/bbl)
Fourth quarter U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(2.00)/bbl
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.80)/Mcf (from US$(0.75)/Mcf)
Fourth quarter Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(1.05)/Mcf

(1) Excluding 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)	2017	2016	2017	2016
Oil and natural gas sales	$ 241.9	$ 230.4	$ 801.7	$ 613.6
Less:				
Royalties	(45.8)	(42.1)	(152.1)	(108.3)
Production taxes	(12.3)	(10.4)	(36.5)	(26.4)
Cash operating expenses[1]	(48.9)	(56.2)	(145.4)	(189.9)
Transportation costs	(26.3)	(28.8)	(85.1)	(78.9)
Netback before hedging	$ 108.6	$ 92.9	$ 382.6	$ 210.1
Cash gains/(losses) on derivative instruments	2.9	10.0	11.7	71.1
Netback after hedging	$ 111.5	$ 102.9	$ 394.3	$ 281.2

(1) Total operating expenses have been adjusted to exclude non-cash gains on fixed price electricity swaps of $0.1 million and $0.4 million for the three and nine months ended September 30, 2017, and nil and $0.5 million, respectively, for the three and nine months ended September 30, 2016.

"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 September 30,		Nine months ended September 30,	
($ millions)	2017	2016	2017	2016
Cash flow from operating activities	$ 114.6	$ 105.9	$ 340.8	$ 237.6
Asset retirement obligation expenditures	3.1	1.2	7.1	4.4
Changes in non-cash operating working capital	(27.3)	(27.0)	(23.4)	(44.1)
Adjusted funds flow	$ 90.4	$ 80.1	$ 324.5	$ 197.9

"Total debt net of cash" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. Total debt net of cash is calculated as senior notes plus any outstanding bank credit facility balance, minus cash and 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)	2017	2016	2017	2016
Dividends	$ 7.3	$ 7.2	$ 21.8	$ 28.2
Capital and office expenditures	119.6	60.9	342.2	152.4
Sub-total	$ 126.9	$ 68.1	$ 364.0	$ 180.6
Adjusted funds flow	$ 90.4	$ 80.1	$ 324.5	$ 197.9
Adjusted payout ratio (%)	140%	85%	112%	91%

"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, 2017
Net income/(loss)	$ 1,062.1
Add:	
Interest	39.2
Current and deferred tax expense/(recovery)	(508.3)
DD&A and asset impairment	294.4
Other non-cash charges(2)	(10.5)
Sub-total	$ 876.9
Adjustment for material acquisitions and divestments(3)	(19.5)
Adjusted EBITDA	$ 857.4

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at September 30, 2017 include the nine months ended September 30, 2017 and the fourth quarter of 2016.
(2) Includes the change in fair value of commodity derivatives, fixed price electricity swaps and equity swaps, non-cash SBC, and unrealized foreign exchange gains/losses.
(3) EBITDA is adjusted for material acquisitions or divestments during the period with net proceeds greater than $50 million as if that acquisition or disposition had been made at the beginning of the period.

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections 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 September 30, 2017, 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, 2017 and ended September 30, 2017 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 2017 total, fourth quarter 2017 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 2017 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 2017 and impact thereof on our production levels and land holdings; potential future asset and goodwill impairments, as well as relevant factors that may affect such impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes 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 2017 guidance contained in this MD&A is based on the following prices for the fourth quarter: a WTI price of US$50.00/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.00/GJ and a USD/CDN exchange rate of 1.28. 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, 2016).

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.