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

The following discussion and analysis of financial results is dated August 4, 2016 and is to be read in conjunction with:

- the unaudited interim consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three and six months ended June 30, 2016 and 2015 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2015 and 2014 and for the years ended December 31, 2015, 2014 and 2013; and
- our MD&A for the year ended December 31, 2015 (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.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. 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

During the second quarter, we continued to position ourselves to deliver profitable growth in a low commodity price environment. The proceeds from our equity issuance and the ongoing success of our non-core asset divestment program allowed us to significantly reduce our debt and strengthen our balance sheet. Operationally, our assets continue to deliver strong results with improving cost structures.

On May 31, 2016, we completed an equity financing for 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million net of issue costs). Our non-core asset divestment program continued to provide significant liquidity, with proceeds of $92.7 million during the second quarter and total proceeds of approximately $280.5 million to date in 2016. These proceeds were used to fully repay our drawn credit facility and fund the repurchase of an additional US$95 million of our senior notes during the quarter, for a total repurchase of US$267 million of senior notes to date, at prices ranging from 90% of par to par value. Through these steps we have reduced our total debt net of cash by 45% to $674.1 million at June 30, 2016 from $1,216.2 million at December 31, 2015.

Average daily production for the second quarter was 93,659 BOE/day, at the high end of our annual average production guidance range, and as a result we are increasing the low end of our annual guidance range to 92,000 BOE/day, with the upper end remaining at 94,000 BOE/day. We continue to expect to produce approximately 43,000 – 45,000 bbls/day of crude oil and natural gas liquids. Production decreased approximately 4% from the first quarter of 2016 largely due to the first quarter sale of our Canadian Deep Basin natural gas properties, along with overall decline in Canadian production volumes as a result of lower capital spending. Production volumes in the U.S. remained flat compared to the prior quarter, with the impact of lower capital spending offset by strong performance in the Marcellus and Fort Berthold areas.

We maintained a disciplined capital program, spending $48.1 million during the second quarter and $91.4 million year to date, with the majority directed to our Fort Berthold properties. We are modestly increasing our spending in Fort Berthold during the second half of the year to position ourselves for growth in 2017. We plan to spend an additional $15 million on three gross completions and pre-spending on facilities, and are projecting our fourth quarter production to increase by approximately 1,000 BOE/day. As a result, we are increasing our 2016 capital guidance to $215 million from $200 million, which is expected to be funded through internally generated cash flow at current forward strip commodity prices.

Operating expenses came in below guidance of $8.50/BOE, totaling $60.5 million or $7.10/BOE during the second quarter. The decrease in operating costs was mainly due to the ongoing success of our cost savings initiatives, reduced activity levels and continued improvement in pricing for materials and services, along with the divestment of higher cost Canadian properties. As a result, we are reducing our annual guidance for operating expenses to $7.90/BOE from $8.50/BOE. Cash G&A expenses were also below guidance, totaling $14.6 million or $1.71/BOE compared to guidance of $2.00/BOE, primarily due to a reduction in staff levels. Accordingly, we are revising our annual cash G&A expense guidance to $1.95/BOE from $2.00/BOE.

Our commodity hedging program continued to provide funds flow protection, contributing cash gains of $21.6 million in the second quarter. We added additional downside protection during the second quarter, and as of July 22, 2016, we have approximately 39% of our forecasted 2016 crude oil production, net of royalties, hedged for the remainder of 2016 and 2017. We have also hedged approximately 29% of our forecasted 2016 natural gas production, net of royalties, for the remainder of 2016 and approximately 20% for 2017.

We recorded a net loss of $168.6 million and funds flow of $76.0 million for the quarter. Second quarter earnings included gains of $74.7 million on asset divestments and $12.2 million on the repurchase of senior notes. These gains were offset by a non-cash impairment charge of $148.7 million and a non-cash valuation allowance on our deferred tax asset of $105.0 million as a result of the decline in the twelve month trailing average commodity prices.

RESULTS OF OPERATIONS

Production

Production for the second quarter totaled 93,659 BOE/day, at the high end of our annual average guidance range of 90,000 – 94,000 BOE/day. Compared to production in the first quarter of 2016 of 97,860 BOE/day, production decreased 4% primarily due to the first quarter sale of Canadian Deep Basin natural gas properties with production of approximately 5,400 BOE/day.

Production in the second quarter of 2016 decreased 13% from production levels of 107,429 BOE/day in the same period of 2015 primarily due to the sale of non-core properties with production of approximately 9,000 BOE/day during the second half of 2015 and the first quarter of 2016. This excludes the June sale of approximately 2,300 BOE/day of non-core Canadian assets. Production volumes from our Canadian assets were further impacted by the reduction in capital spending in 2015 and 2016, while strong performance from our U.S. assets offset any decline due to lower spending.

As a result of the sale of the Deep Basin natural gas properties and other non-core Canadian shallow gas properties, our crude oil and natural gas liquids weighting increased to 47% of our total average daily production in the second quarter of 2016, from 46% in the first quarter of 2016 and 43% in the second quarter of 2015.

Average daily production volumes for the three and six months ended June 30, 2016 and 2015 are outlined below:

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2016**	**2015**	**% Change**	**2016**	**2015**	**% Change**
Crude oil (bbls/day)	39,079	41,122	(5%)	39,294	40,243	(2%)
Natural gas liquids (bbls/day)	4,829	5,145	(6%)	5,161	4,444	16%
Natural gas (Mcf/day)	298,503	366,971	(19%)	307,827	356,836	(14%)
Total daily sales (BOE/day)	93,659	107,429	(13%)	95,759	104,160	(8%)

As a result of strong performance and higher natural gas prices expected in the Marcellus, and despite the sale of approximately 2,300 BOE/day of non-core assets in June, we are increasing the lower end of our average annual production guidance to 92,000 – 94,000 BOE/day from 90,000 – 94,000 BOE/day. We are maintaining our annual crude oil and natural gas liquids production guidance of 43,000 – 45,000 bbls/day. This guidance does not include any additional acquisitions or divestments.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, funds flow and financial condition. The following table compares average prices from the first half of 2016 to the first half of 2015 and other periods indicated:

Pricing (average for the period)	**Six months ended June 30, 2016**	**2015**	**Q2 2016**	**Q1 2016**	**Q4 2015**	**Q3 2015**	**Q2 2015**
Benchmarks							
WTI crude oil (US$/bbl)	$ 39.52	$ 53.29	$ 45.59	$ 33.45	$ 42.18	$ 46.43	$ 57.94
AECO natural gas – monthly index ($/Mcf)	1.68	2.81	1.25	2.11	2.65	2.80	2.67
AECO natural gas – daily index ($/Mcf)	1.62	2.70	1.40	1.83	2.47	2.90	2.64
NYMEX natural gas – last day (US$/Mcf)	2.02	2.81	1.95	2.09	2.27	2.77	2.64
USD/CDN average exchange rate	1.33	1.24	1.29	1.37	1.34	1.31	1.23
USD/CDN period end exchange rate	1.30	1.25	1.30	1.30	1.38	1.34	1.25
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 39.00	$ 51.35	$ 46.48	$ 31.59	$ 43.04	$ 48.22	$ 58.26
Natural gas liquids ($/bbl)	13.37	21.55	15.67	11.34	16.61	13.51	20.88
Natural gas ($/Mcf)	1.64	2.32	1.49	1.77	1.89	2.08	2.09
Average differentials							
MSW Edmonton – WTI (US$/bbl)	$ (3.39)	$ (4.93)	$ (3.09)	$ (3.69)	$ (2.44)	$ (3.42)	$ (3.06)
WCS Hardisty – WTI (US$/bbl)	(13.77)	(13.16)	(13.30)	(14.24)	(14.50)	(13.27)	(11.59)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.84)	(1.63)	(0.70)	(0.99)	(1.15)	(1.66)	(1.50)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.90)	(1.67)	(0.73)	(1.07)	(1.23)	(1.75)	(1.57)
AECO monthly – NYMEX (US$/Mcf)	(0.76)	(0.54)	(0.99)	(0.56)	(0.28)	(0.63)	(0.47)
Enerplus realized differentials(1)							
Canada crude oil – WTI (US$/bbl)	$ (13.46)	$ (14.13)	$ (12.01)	$ (14.14)	$ (13.63)	$ (11.82)	$ (12.50)
Canada natural gas – NYMEX (US$/Mcf)	(0.74)	(0.46)	(0.86)	(0.63)	(0.42)	(0.43)	(0.46)
Bakken crude oil – WTI (US$/bbl)	(8.29)	(10.05)	(8.23)	(8.38)	(7.93)	(8.52)	(9.30)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.83)	(1.35)	(0.76)	(0.91)	(1.13)	(1.64)	(1.39)

(1) Before transportation costs, royalties and commodity derivative instruments.

CRUDE OIL AND NATURAL GAS LIQUIDS

Our average realized crude oil price during the second quarter was $46.48/bbl, an increase of 47% compared to the prior quarter as a result of the higher benchmark crude oil prices and narrowing Canadian differentials. WTI crude oil prices increased by 36% to average US$45.59/bbl in the quarter due to improving seasonal demand for crude oil in the U.S. combined with lower overall U.S. production. Canadian light and heavy crude oil differentials improved by 16% and 7%, respectively, when compared to the previous quarter, due to industry wide production outages resulting from the severe wildfires in northern Alberta. These outages also helped U.S. Bakken crude oil differentials to improve by 2%. In the second quarter our realized natural gas liquids price increased by 38% compared to the first quarter, in-line with the increases in benchmark crude oil and liquids prices during the quarter.

NATURAL GAS

Our average realized natural gas price during the second quarter was $1.49/Mcf, 16% lower when compared to the prior quarter. Benchmark NYMEX and AECO monthly natural gas prices in the second quarter fell by 7% and 41%, respectively, compared to the previous quarter due to high inventory levels as a result of one of the warmest winters on record. Approximately 33% of our second quarter Canadian gas production was sold under fixed basis contracts. As a result, our realized Canadian natural gas price differential significantly outperformed the AECO benchmark price, averaging US$0.86/Mcf below NYMEX during the quarter compared to the benchmark AECO monthly differential of US$0.99/Mcf below NYMEX.

Industry rig counts in the Marcellus region have fallen dramatically over the past year, resulting in lower production growth in Northeast Pennsylvania and improved price differentials to NYMEX. Monthly differentials at Transco Leidy and TGP Zone 4 300 Leg improved by 29% and 32%, respectively, compared to the prior quarter and 53% compared to the second quarter of 2015. In comparison, our realized Marcellus differential improved by 16% during the second quarter, and 45% compared to the same period last year, to average US$0.76/Mcf below NYMEX. With a portion of our second quarter natural gas sales exposed to other regional prices that were seasonally weaker, our Marcellus realized differential did not improve as much as the local Leidy and TGP benchmarks.

FOREIGN EXCHANGE

The Canadian dollar strengthened throughout the second quarter as a result of higher crude oil prices. The USD/CDN exchange rate was 1.30 USD/CDN at June 30, 2016, and averaged 1.29 USD/CDN during the second quarter compared to 1.37 USD/CDN during the first quarter. 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, the economics of our capital program and potential acquisitions. Since our first quarter, we have added additional floor protection on a portion of our oil and natural gas production for 2016 and 2017.

As of July 22, 2016, we have hedged 12,000 bbls/day of our expected crude oil production for the remainder of 2016 and 2017, which represents approximately 39% of our forecasted 2016 net crude oil production, after royalties. Price protection levels are shown in the table below. For the second half of 2016 and the full year of 2017, we have floor protection at an effective price of US$57.82/bbl and US$50.00/bbl, respectively. When WTI prices settle below the sold put strike price in any given month, the three way collars provide protection of approximately US$12.73/bbl and US$11.41/bbl above the WTI index prices in 2016 and 2017, respectively. Overall, we expect our crude oil related hedge contracts to protect a significant portion of our funds flow.

As of July 22, 2016, we have hedged approximately 66,700 Mcf/day of our expected natural gas production for the remainder of 2016 consisting of a combination of NYMEX swaps and collars. This represents approximately 29% of our forecasted natural gas production, after royalties. For 2017 we have hedged 45,000 Mcf/day or approximately 20% of our forecasted 2016 natural gas production, after royalties, using three way collars. Price protection levels are shown in the table below. With regards to the NYMEX three way collars, when NYMEX prices settle below the sold put strike price in any given month, the three way collars provide protection of approximately US$0.50/Mcf and US$0.69/Mcf above the NYMEX index price in 2016 and 2017, respectively.

The following is a summary of our financial contracts in place at July 22, 2016, expressed as a percentage of our anticipated net 2016 production volumes:

	WTI Crude Oil (US$/bbl)[(1)]		NYMEX Natural Gas (US$/Mcf)[(1)]		
	Jul 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Dec 31, 2017	Jul 1, 2016 – Oct 31, 2016	Nov 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Dec 31, 2017
Sold Swaps	–	–	$ 2.53	$ 2.48	–
%	–	–	22%	11%	–
Three Way Collars					
Sold Puts	$ 45.09	$ 38.59	$ 2.50	$ 2.50	$ 2.03
%	39%	39%	11%	11%	20%
Purchased Puts	$ 57.82	$ 50.00	$ 3.00	$ 3.00	$ 2.72
%	39%	39%	11%	11%	20%
Sold Calls	$ 71.75	$ 60.50	$ 3.75	$ 3.75	$ 3.37
%	39%	39%	11%	11%	20%

(1) Based on weighted average price (before premiums), assuming average annual production of 93,000 BOE/day for 2016 and 2017 less royalties and production taxes of 22% in aggregate.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2016**	**2015**	**2016**	**2015**
Cash gains/(losses):				
Crude oil	$ 16.4	$ 56.7	$ 52.9	$ 127.2
Natural gas	5.2	16.4	8.3	32.7
Total cash gains/(losses)	$ 21.6	$ 73.1	$ 61.2	$ 159.9
Non-cash gains/(losses):				
Crude oil	$ (27.2)	$ (71.1)	$ (58.4)	$ (107.1)
Natural gas	(16.3)	(21.8)	(11.2)	(22.2)
Total non-cash gains/(losses)	$ (43.5)	$ (92.9)	$ (69.6)	$ (129.3)
Total gains/(losses)	$ (21.9)	$ (19.8)	$ (8.4)	$ 30.6

	Three months ended June 30,		**Six months ended June 30,**	
(Per BOE)	**2016**	**2015**	**2016**	**2015**
Total cash gains/(losses)	$ 2.53	$ 7.47	$ 3.51	$ 8.48
Total non-cash gains/(losses)	(5.10)	(9.49)	(3.99)	(6.85)
Total gains/(losses)	$ (2.57)	$ (2.02)	$ (0.48)	$ 1.63

During the second quarter of 2016 we realized cash gains of $16.4 million on our crude oil contracts and $5.2 million on our natural gas contracts. In comparison, during the second quarter of 2015 we realized cash gains of $56.7 million on our crude oil contracts and $16.4 million on our natural gas contracts. The cash gains were due to contracts which provided floor protection above market prices.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and 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 2016 the fair value of our crude oil contracts represented a net gain position of $9.0 million, while our natural gas contracts represented a net loss position of $7.2 million. For the three and six months ended June 30, 2016, the change in the fair value of our crude oil contracts represented losses of $27.2 million and $58.4 million, respectively, and our natural gas contracts represented losses of $16.3 million and $11.2 million, respectively.

Revenues

	Three months ended June 30,		**Six months ended June 30,**	
($ millions)	**2016**	**2015**	**2016**	**2015**
Oil and natural gas sales	$ 212.7	$ 298.4	$ 383.2	$ 542.5
Royalties	(38.4)	(46.7)	(66.2)	(85.8)
Oil and natural gas sales, net of royalties	$ 174.3	$ 251.7	$ 317.0	$ 456.7

Oil and natural gas revenues for the three and six months ended June 30, 2016 were $212.7 million and $383.2 million, respectively, a decrease of 31% from the same periods in 2015. The decrease in revenue was a result of the decline in oil and natural gas prices over the respective periods, as well as the impact of lower production volumes.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Royalties	$ 38.4	$ 46.7	$ 66.2	$ 85.8
Per BOE	$ 4.51	$ 4.78	$ 3.80	$ 4.55
Production taxes	$ 8.6	$ 14.2	$ 16.0	$ 25.0
Per BOE	$ 1.00	$ 1.45	$ 0.92	$ 1.33
Royalties and production taxes	$ 47.0	$ 60.9	$ 82.2	$ 110.8
Per BOE	$ 5.51	$ 6.23	$ 4.72	$ 5.88
Royalties and production taxes (% of oil and natural gas sales)	22%	20%	21%	20%

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 not as sensitive to commodity price levels. During the three and six months ended June 30, 2016, royalties and production taxes decreased to $47.0 million and $82.2 million, respectively, from $60.9 million and $110.8 million for the same periods in 2015, primarily due to lower realized prices and lower production volumes. Royalties and production taxes averaged 21% of oil and natural gas sales before transportation costs in the first half of 2016 compared to 20% for the same period in 2015 due to increased production from our U.S. properties.

We have revised our average royalty and production tax rate guidance to 22% of oil and gas sales for 2016 from 23%. We do not expect the recently announced Alberta modernized royalty framework to have a significant impact on our Canadian royalties.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Cash operating expenses	$ 61.4	$ 79.3	$ 133.7	$ 166.2
Non-cash (gains)/losses[1]	(0.9)	(2.6)	(0.6)	(1.7)
Total operating expenses	$ 60.5	$ 76.7	$ 133.1	$ 164.5
Per BOE	$ 7.10	$ 7.85	$ 7.64	$ 8.72

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

For the three and six months ended June 30, 2016, operating expenses were $60.5 million and $133.1 million, respectively, a decrease of 21% and 19% compared to the same periods in 2015. On a per BOE basis, operating costs for the three and six months ended June 30, 2016 were $7.10/BOE and $7.64/BOE, outperforming our annual guidance of $8.50/BOE. The decrease in operating costs was mainly a result of our continued cost saving initiatives and the divestment of higher operating cost Canadian properties over the last year.

Based on cost savings to date, we are reducing our 2016 guidance for operating expenses to $7.90/BOE from $8.50/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Transportation costs	$ 24.5	$ 28.0	$ 50.2	$ 54.5
Per BOE	$ 2.87	$ 2.87	$ 2.88	$ 2.89

For the three and six months ended June 30, 2016, transportation costs were $24.5 million ($2.87/BOE) and $50.2 million ($2.88/BOE), respectively, compared to $28.0 million ($2.87/BOE) and $54.5 million ($2.89/BOE) for the same periods in 2015. The decrease in transportation costs was primarily due to lower production.

We are maintaining our 2016 guidance for transportation costs of $3.10/BOE. Although year to date transportation costs are below our annual guidance, effective August 2016 we have firm transportation commitments for 30,000 Mcf/day of additional interstate pipeline capacity from the Marcellus region to downstream connections at pricing of US$0.71/Mcf.

Netbacks

The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A.

	Three months ended June 30, 2016		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	46,972 BOE/day	280,122 Mcfe/day	93,659 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 40.57	$ 1.54	$ 24.96
Royalties and production taxes	(9.57)	(0.24)	(5.51)
Cash operating expenses	(10.04)	(0.73)	(7.20)
Transportation costs	(1.85)	(0.64)	(2.87)
Netback before hedging	$ 19.11	$ (0.07)	$ 9.38
Cash gains/(losses)	3.83	0.20	2.53
Netback after hedging	$ 22.94	$ 0.13	$ 11.91
Netback before hedging ($ millions)	$ 81.6	$ (1.8)	$ 79.8
Netback after hedging ($ millions)	$ 98.0	$ 3.4	$ 101.4

	Three months ended June 30, 2015		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	49,058 BOE/day	350,226 Mcfe/day	107,429 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 52.17	$ 2.06	$ 30.53
Royalties and production taxes	(12.15)	(0.21)	(6.23)
Cash operating expenses	(11.27)	(0.91)	(8.12)
Transportation costs	(1.68)	(0.64)	(2.87)
Netback before hedging	$ 27.07	$ 0.30	$ 13.31
Cash gains/(losses)	12.69	0.52	7.47
Netback after hedging	$ 39.76	$ 0.82	$ 20.78
Netback before hedging ($ millions)	$ 121.0	$ 9.2	$ 130.2
Netback after hedging ($ millions)	$ 177.6	$ 25.7	$ 203.3

	Six months ended June 30, 2016		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	47,836 BOE/day	287,538 Mcfe/day	95,759 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 33.82	$ 1.70	$ 21.99
Royalties and production taxes	(7.95)	(0.25)	(4.72)
Cash operating expenses	(10.06)	(0.88)	(7.67)
Transportation costs	(1.85)	(0.65)	(2.88)
Netback before hedging	$ 13.96	$ (0.08)	$ 6.72
Cash gains/(losses)	6.08	0.16	3.51
Netback after hedging	$ 20.04	$ 0.08	$ 10.23
Netback before hedging ($ millions)	$ 121.5	$ (4.4)	$ 117.1
Netback after hedging ($ millions)	$ 174.5	$ 3.8	$ 178.3

Netbacks by Property Type	Six months ended June 30, 2015 Crude Oil	Natural Gas	Total
Average Daily Production	46,916 BOE/day	343,464 Mcfe/day	104,160 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 46.98	$ 2.31	$ 28.78
Royalties and production taxes	(10.99)	(0.28)	(5.88)
Cash operating expenses	(12.31)	(0.99)	(8.81)
Transportation costs	(1.82)	(0.63)	(2.89)
Netback before hedging	$ 21.86	$ 0.41	$ 11.20
Cash gains/(losses)	14.98	0.53	8.48
Netback after hedging	$ 36.84	$ 0.94	$ 19.68
Netback before hedging ($ millions)	$ 185.6	$ 25.4	$ 211.0
Netback after hedging ($ millions)	$ 312.9	$ 58.0	$ 370.9

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

Crude oil and natural gas netbacks per BOE decreased for the three and six months ended June 30, 2016 compared to the same periods in 2015 primarily due to lower commodity prices and lower realized hedging gains. Our crude oil properties accounted for substantially all of our netback, both before and after hedging.

General and Administrative 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") and our stock option plan. See Note 10 and Note 14 to the Interim Financial Statements for further details.

($ millions)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Cash:				
G&A expense	$ 14.6	$ 19.9	$ 33.0	$ 41.3
Share-based compensation expense	0.8	(1.2)	1.5	6.0
Non-Cash:				
Share-based compensation expense	5.4	4.6	8.9	9.6
Equity swap loss/(gain)	(1.6)	1.0	(1.7)	(0.6)
Total G&A expenses	$ 19.2	$ 24.3	$ 41.7	$ 56.3

(Per BOE)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Cash:				
G&A expense	$ 1.71	$ 2.03	$ 1.89	$ 2.19
Share-based compensation expense	0.09	(0.13)	0.09	0.32
Non-Cash:				
Share-based compensation expense	0.63	0.47	0.51	0.51
Equity swap loss/(gain)	(0.18)	0.11	(0.10)	(0.03)
Total G&A expenses	$ 2.25	$ 2.48	$ 2.39	$ 2.99

For the three and six months ended June 30, 2016, cash G&A expenses were $14.6 million ($1.71/BOE) and $33.0 million ($1.89/BOE), respectively, compared to $19.9 million ($2.03/BOE) and $41.3 million ($2.19/BOE) for the same periods in 2015. The decrease in cash G&A expenses from the prior year was primarily due to a 30% reduction in staff levels throughout 2015 and to date in 2016, offset by one-time severance payments, as we continue to respond to the current commodity price environment.

During the quarter, our share price increased by 67% resulting in a cash SBC expense of $0.8 million ($0.09/BOE) compared to a recovery of $1.2 million ($0.13/BOE) in the same period of 2015. We recorded non-cash SBC of $5.4 million ($0.63/BOE) in the second quarter compared to $4.6 million ($0.47/BOE) during the same period in 2015. The increase in non-cash SBC was due to the additional expense related to the 2016 grant.

We have hedged a portion of the outstanding cash settled grants under our LTI plans. As a result of the increase in our share price during the quarter we recorded a non-cash mark-to-market gain of $1.6 million on these hedges. As of June 30, 2016 we had 470,000 units hedged at a weighted average price of $16.89 per share.

Based on our continued focus on costs, we are reducing our 2016 guidance for cash G&A expenses to $1.95/BOE from $2.00/BOE.

Interest Expense

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2016	2015	2016	2015
Interest on senior notes and bank facility	$ 10.0	$ 15.9	$ 24.6	$ 32.7
Non-cash interest expense	0.6	0.2	0.8	0.5
Total interest expense	$ 10.6	$ 16.1	$ 25.4	$ 33.2

For the three and six months ended June 30, 2016, we recorded total interest expense of $10.6 million and $25.4 million, respectively, compared to $16.1 million and $33.2 million for the same periods in 2015. The decrease in interest expense corresponds to a decrease in the aggregate principal amount of our outstanding senior notes following our repurchase of US$267 million of senior notes during the first half of 2016. The repurchase of senior notes was funded by asset divestment proceeds and lower interest rate bank debt, which was repaid in full following our May 31, 2016 equity financing and the closing of our previously announced Canadian non-core asset divestment.

At June 30, 2016, our bank credit facility was undrawn, and our debt balance consisted solely of fixed interest rate senior notes with a weighted average interest rate of 5.0%.

Foreign Exchange

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2016	2015	2016	2015
Realized loss/(gain)	$ 0.3	$ 8.4	$ 2.0	$ (27.2)
Unrealized loss/(gain)	0.1	(36.1)	(56.0)	103.7
Total foreign exchange loss/(gain)	$ 0.4	$ (27.7)	$ (54.0)	$ 76.5
USD/CDN average exchange rate	1.29	1.23	1.33	1.24

For the three and six months ended June 30, 2016, we recorded a net foreign exchange loss of $0.4 million and a net foreign exchange gain of $54.0 million, respectively, compared to a gain of $27.7 million and a loss of $76.5 million for the same periods in 2015. Realized losses related to day-to-day transactions recorded in foreign currencies. During the six months ended June 30, 2015 we recorded realized gains of $27.2 million primarily due to a $39.9 million gain on the unwind of certain foreign exchange swaps offset by losses on our foreign exchange collars.

Unrealized foreign exchange gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. Comparing June 30, 2016 to December 31, 2015, the Canadian dollar strengthened relative to the U.S. dollar resulting in unrealized gains of $56.0 million. See Note 12 to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Capital spending	$ 48.1	$ 148.0	$ 91.4	$ 315.0
Office capital	0.1	1.4	0.1	2.3
Sub-total	48.2	149.4	91.5	317.3
Property and land acquisitions	$ 0.3	$ (1.0)	$ 3.9	$ (1.2)
Property divestments	(92.7)	(187.8)	(280.5)	(191.5)
Sub-total	(92.4)	(188.8)	(276.6)	(192.7)
Total	$ (44.2)	$ (39.4)	$ (185.1)	$ 124.6

Capital spending for the three and six months ended June 30, 2016, totaled $48.1 million and $91.4 million, respectively, compared to $148.0 million and $315.0 million for the same periods in 2015. The decrease is in-line with our reduced spending program for 2016, as we continue to invest modestly in our core areas. During the second quarter we spent $30.4 million on our Fort Berthold crude oil properties, $7.1 million on our Canadian crude properties and $9.4 million on our Marcellus assets.

In June 2016, we completed the previously announced sale of non-core properties in northwest Alberta for proceeds of $92.7 million, net of closing costs, with estimated 2016 production of approximately 2,300 BOE/day. In comparison, during the second quarter of 2015, we sold non-core assets with proceeds of $187.8 million, including our Pembina waterflood assets. Year to date, we have recorded total proceeds on asset divestments of $280.5 million, compared to $191.5 million in the same period of 2015.

We are increasing our 2016 capital guidance by $15 million to $215 million to begin to position ourselves for growth in 2017. The incremental capital will be directed to Fort Berthold, and includes the addition of three gross completions as well as pre-spending on our facilities during the second half of the year. We expect the additional spending to increase our fourth quarter production by approximately 1,000 BOE/day and to be funded through internally generated cash flow at current forward strip commodity prices.

Gain on Asset Sales and Note Repurchases

We recorded a gain of $74.7 million on the sale of non-core Canadian properties during the second quarter of 2016, bringing our year to date gain on asset divestments to $219.8 million. Under full cost accounting rules, divestitures 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.

During the second quarter of 2016, we recorded a gain of $12.2 million on the repurchase of US$95 million of outstanding senior notes at a discount to par value. Year to date, we have repurchased a total of US$267 million of senior notes at prices between 90% of par and par value, resulting in a total gain of $19.3 million.

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

($ millions, except per BOE amounts)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
DD&A expense	$ 82.3	$ 137.4	$ 173.5	$ 269.8
Per BOE	$ 9.66	$ 14.06	$ 9.95	$ 14.31

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three and six months ended June 30, 2016, DD&A decreased when compared the same periods of 2015 primarily due to the cumulative effects of asset impairments recorded during 2015 and the first quarter of 2016.

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 continued to decline in the first half of 2016 but less significantly than in 2015. Non-cash impairments of $148.7 million and $194.9 million were recorded for the three and six months ended June 30, 2016, respectively, compared to $497.2 million and $764.9 million in the same periods of 2015.

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. For the remainder of this year, 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. Although the trailing twelve month average commodity prices are near current levels, there is the potential for prices to decline further during 2016, impacting the ceiling value and resulting in further non-cash impairments. See Note 5 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 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 $188.2 million at June 30, 2016, compared to $206.4 million at December 31, 2015. For the three and six months ended June 30, 2016, asset retirement obligation settlements were $0.8 million and $3.2 million, respectively, compared to $2.6 million and $6.5 million during the same periods in 2015. As a result of our divestments to date in 2016, we have reduced our asset retirement obligation by $22.6 million.

Income Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2016	2015	2016	2015
Current tax expense/(recovery)	$ (0.2)	$ (0.1)	$ (0.4)	$ –
Deferred tax expenses/(recovery)	53.3	(221.7)	309.8	(360.1)
Total tax expense/(recovery)	$ 53.1	$ (221.8)	$ 309.4	$ (360.1)

For the three and six months ended June 30, 2016 we recorded total tax expense of $53.1 million and $309.4 million, respectively, compared to a tax recovery of $221.8 million and $360.1 million for the same periods in 2015. The current quarter expense includes an additional valuation allowance of $105.0 million recorded against our deferred income tax asset, partially offset by a recovery due to the non-cash asset impairment expense recorded in the U.S. and Canada. 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 assessment is primarily based on a projection of undiscounted future taxable income using historical trailing twelve month benchmark prices. After recording the valuation allowance, our overall net deferred income tax asset was $186.7 million at June 30, 2016 compared to $516.1 million at December 31, 2015.

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, 2016, our senior debt to adjusted EBITDA ratio was 1.2x and our debt to funds flow ratio was 2.0x. Although it is not included in our debt covenants, the debt to funds flow ratio is often used by investors and analysts to evaluate our liquidity.

We have continued to be diligent in managing and preserving our financial position. On May 31, 2016 we completed an equity financing for 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million net of issue costs). Our non-core asset divestment program continued to provide significant liquidity, with proceeds of $92.7 million during the second quarter and total proceeds of approximately $280.5 million to date in 2016. These proceeds were used to fully repay our drawn credit facility and fund the repurchase of US$95 million of our senior notes during the quarter, and a total of US$267 million of senior notes to date. The senior note repurchases were completed at prices ranging from 90% of par to par value, resulting in a total gain of $19.3 million for the six months ended June 30, 2016. Furthermore, as a result of the note repurchases we expect to save approximately US$13 million in interest expense on an annualized basis.

Following the equity financing and non-core asset divestments, total debt net of cash at June 30, 2016 was $674.1 million, a decrease of 45% compared to $1,216.2 million at December 31, 2015. At June 30, 2016, we had $723.3 million of senior notes outstanding less $49.2 million in cash and our $800 million bank credit facility was undrawn.

We continued to maintain our financial flexibility through an ongoing focus on cost efficiencies and disciplined capital spending. Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by funds flow, was 72% and 96% for the three and six months ended June 30, 2016, compared to 112% and 147% for the same periods in 2015. After adjusting for net acquisition and divestment proceeds, we had a funding surplus of $282.0 million for the six months ended June 30, 2016.

Our working capital deficiency, excluding cash and current deferred financial assets and liabilities, decreased to $88.5 million at June 30, 2016 from $104.0 million at December 31, 2015. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, 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, 2016, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Based on our current guidance, we expect to manage our business within these financial ratios; however, current oil and gas prices have created a significant level of uncertainty which may challenge the assumptions and estimates used in management's forecast. If we exceed any of the covenants, we may be required to repay, refinance or renegotiate the terms of the debt. If we reach or exceed these covenant thresholds, there are a number of steps that may be taken to improve them, including asset divestments, a reduction to capital spending and equity issuances.

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 June 30, 2016:

Covenant Description		June 30, 2016
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA(1)	3.5 x	1.2 x
Total debt to adjusted EBITDA	4.0 x	1.2 x
Total debt to capitalization	50%	29%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA(2)	3.0 x – 3.5 x	1.2 x
Senior debt to consolidated present value of total proved reserves(3)	60%	32%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0 x	10.3 x

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, 2016 were $170.7 million and $603.2 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

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per share amounts)	2016	2015	2016	2015
Dividends to shareholders	$ 6.5	$ 30.9	$ 21.0	$ 78.3
Per weighted average share (Basic)	$ 0.03	$ 0.15	$ 0.10	$ 0.38

During the three and six months ended June 30, 2016, we reported total dividends of $6.5 million or $0.03 per share and $21.0 million or $0.10 per share, respectively, compared to $30.9 million or $0.15 per share and $78.3 million or $0.38 per share for the same periods in 2015.

Effective with the April 2016 payment, we reduced the monthly dividend by 67% from $0.03 per share to $0.01 per share to provide additional financial flexibility and to balance funds flow with capital and dividends. The dividend is an important part of our strategy to create shareholder value and we will continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Six months ended June 30,	
	2016	2015
Share capital ($ millions)	$ 3,366.0	$ 3,126.6
Common shares outstanding (thousands)	240,483	206,224
Weighted average shares outstanding – basic (thousands)	212,420	206,028
Weighted average shares outstanding – diluted (thousands)	212,420	206,028

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).

During the second quarter no shares were issued pursuant to the stock option plan and the treasury settled LTI plans, resulting in no additional equity for the company (2015 – 45,000; $0.6 million). For the six months ended June 30, 2016 a total of 594,000 shares were issued pursuant to the treasury settled Restricted Share Unit plan resulting in $9.4 million of additional equity (2015 – 492,000; $6.3 million). For further details see Note 14 to the Interim Financial Statements.

At August 4, 2016 we had 240,483,000 shares outstanding.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

($ millions, except per unit amounts)	Three months ended June 30, 2016 Canada	U.S.	Total	Three months ended June 30, 2015 Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	13,497	25,582	39,079	15,462	25,660	41,122
Natural gas liquids (bbls/day)	1,418	3,411	4,829	2,136	3,009	5,145
Natural gas (Mcf/day)	79,878	218,625	298,503	144,788	222,183	366,971
Total average daily production (BOE/day)	28,228	65,431	93,659	41,730	65,699	107,429
Pricing(2)						
Crude oil (per bbl)	$ 43.27	$ 48.18	$ 46.48	$ 55.86	$ 59.71	$ 58.26
Natural gas liquids (per bbl)	25.14	11.74	15.67	33.58	11.87	20.88
Natural gas (per Mcf)	1.41	1.52	1.49	2.68	1.70	2.09
Capital Expenditures						
Capital spending	$ 7.2	$ 40.9	$ 48.1	$ 24.6	$ 123.4	$ 148.0
Acquisitions	1.0	(0.7)	0.3	0.8	(1.8)	(1.0)
Divestments	(91.1)	(1.6)	(92.7)	(187.1)	(0.7)	(187.8)
Netback(3) **Before Hedging**						
Oil and natural gas sales	$ 66.6	$ 146.1	$ 212.7	$ 120.7	$ 177.7	$ 298.4
Royalties	(9.7)	(28.7)	(38.4)	(11.7)	(35.0)	(46.7)
Production taxes	(0.1)	(8.5)	(8.6)	(0.9)	(13.3)	(14.2)
Cash operating expenses	(31.4)	(30.0)	(61.4)	(49.3)	(30.0)	(79.3)
Transportation costs	(3.9)	(20.6)	(24.5)	(5.8)	(22.2)	(28.0)
Netback before hedging	$ 21.5	$ 58.3	$ 79.8	$ 53.0	$ 77.2	$ 130.2
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 21.9	$ –	$ 21.9	$ 19.8	$ –	$ 19.8
General and administrative expense(4)	14.7	4.5	19.2	19.2	5.1	24.3
Current income tax expense/(recovery)	(0.4)	0.2	(0.2)	(0.4)	0.3	(0.1)

($ millions, except per unit amounts)	Six months ended June 30, 2016 Canada	U.S.	Total	Six months ended June 30, 2015 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	13,841	25,453	39,294	16,213	24,030	40,243
Natural gas liquids (bbls/day)	1,612	3,549	5,161	2,247	2,197	4,444
Natural gas (Mcf/day)	89,708	218,119	307,827	140,129	216,707	356,836
Total average daily production (BOE/day)	30,404	65,355	95,759	41,816	62,345	104,160
Pricing[2]						
Crude oil (per bbl)	$ 34.70	$ 41.33	$ 39.00	$ 48.37	$ 53.56	$ 51.35
Natural gas liquids (per bbl)	25.05	8.07	13.37	31.26	11.62	21.55
Natural gas (per Mcf)	1.74	1.59	1.64	2.90	1.95	2.32
Capital Expenditures						
Capital spending	$ 26.3	$ 65.1	$ 91.4	$ 101.5	$ 213.5	$ 315.0
Acquisitions	2.0	1.9	3.9	2.0	(3.2)	(1.2)
Divestments	(279.4)	(1.1)	(280.5)	(188.0)	(3.5)	(191.5)
Netback[3] **Before Hedging**						
Oil and natural gas sales	$ 123.3	$ 259.9	$ 383.2	$ 228.6	$ 313.9	$ 542.5
Royalties	(15.1)	(51.1)	(66.2)	(24.0)	(61.8)	(85.8)
Production taxes	(0.9)	(15.1)	(16.0)	(2.7)	(22.3)	(25.0)
Cash operating expenses	(74.9)	(58.8)	(133.7)	(106.4)	(59.8)	(166.2)
Transportation costs	(7.5)	(42.7)	(50.2)	(12.0)	(42.5)	(54.5)
Netback before hedging	$ 24.9	$ 92.2	$ 117.1	$ 83.5	$ 127.5	$ 211.0
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 8.4	$ –	$ 8.4	$ (30.6)	$ –	$ (30.6)
General and administrative expense[4]	33.1	8.6	41.7	42.7	13.6	56.3
Current income tax expense/(recovery)	(0.7)	0.3	(0.4)	(0.4)	0.4	–

(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	Diluted
2016				
Second Quarter	$ 174.3	$ (168.5)	$ (0.77)	$ (0.77)
First Quarter	142.7	(173.7)	(0.84)	(0.84)
Total 2016	$ 317.0	$ (342.2)	$ (1.61)	$ (1.61)
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)
2014				
Fourth Quarter	$ 325.3	$ 151.7	$ 0.74	$ 0.73
Third Quarter	378.3	67.4	0.33	0.32
Second Quarter	414.9	40.0	0.20	0.19
First Quarter	407.7	40.0	0.20	0.19
Total 2014	$ 1,526.2	$ 299.1	$ 1.46	$ 1.44

Oil and gas sales, net of royalties, increased in the second quarter compared to the first quarter of 2016 due to higher realized crude oil prices partially offset by lower natural gas prices and lower oil and gas production volumes. Oil and gas sales, net of royalties, increased during the first half of 2014, then 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.

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, 2016, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

2016 UPDATED GUIDANCE

We have revised our full year 2016 guidance to reflect a modest increase in capital spend to support 2017 growth, stronger natural gas production from the Marcellus, a lower expected overall royalty expense and reduced operating and G&A expenses. All other guidance has been maintained and is summarized below. This guidance includes the second quarter sale of non-core natural gas properties located in northwest Alberta, but does not include any additional acquisitions or divestments.

Summary of 2016 Expectations	Target
Capital spending	$215 million (from $200 million)
Average annual production	92,000 – 94,000 BOE/day (from 90,000 – 94,000 BOE/day)
Crude oil and natural gas liquids volumes	43,000 – 45,000 bbls/day
Average royalty and production tax rate (% of oil and natural gas sales)	22% (from 23%)
Operating expenses	$7.90/BOE (from $8.50/BOE)
Transportation costs	$3.10/BOE
Cash G&A expenses	$1.95/BOE (from $2.00/BOE)

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 ($ millions)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Oil and natural gas sales	$ 212.7	$ 298.4	$ 383.2	$ 542.5
Less:				
Royalties	(38.4)	(46.7)	(66.2)	(85.8)
Production taxes	(8.6)	(14.2)	(16.0)	(25.0)
Cash operating expenses(1)	(61.4)	(79.3)	(133.7)	(166.2)
Transportation costs	(24.5)	(28.0)	(50.2)	(54.5)
Netback before hedging	$ 79.8	$ 130.2	$ 117.1	$ 211.0
Cash gains/(losses) on derivative instruments	21.6	73.1	61.2	159.9
Netback after hedging	$ 101.4	$ 203.3	$ 178.3	$ 370.9

(1) Total operating expenses adjusted to exclude non-cash gains on fixed price electricity swaps of $0.9 million and $0.6 million in the three and six months ended June 30, 2016 and $2.6 million and $1.7 million in the three and six months ended June 30, 2015.

"Funds Flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. 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 Funds Flow ($ millions)	**Three months ended June 30,** 2016	2015	**Six months ended June 30,** 2016	2015
Cash flow from operating activities	$ 61.9	$ 135.0	$ 131.6	$ 266.2
Asset retirement obligation expenditures	0.7	2.6	3.2	6.5
Changes in non-cash operating working capital	13.4	22.8	(17.0)	(3.1)
Funds flow	$ 76.0	$ 160.4	$ 117.8	$ 269.6

"**Debt to Funds Flow Ratio**" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The debt to funds flow ratio is calculated as total debt net of cash divided by a trailing twelve months of funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depreciation, amortization 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 funds flow.

Calculation of Adjusted Payout Ratio ($ millions)	**Three months ended June 30,** 2016	2015	**Six months ended June 30,** 2016	2015
Dividends	$ 6.5	$ 30.9	$ 21.0	$ 78.3
Capital and office expenditures	48.2	149.4	91.5	317.3
Sub-total	$ 54.7	$ 180.3	$ 112.5	$ 395.6
Funds flow	$ 76.0	$ 160.4	$ 117.8	$ 269.6
Adjusted payout ratio (%)	72%	112%	96%	147%

In addition, the Company uses certain financial measures within the "Liquidity and Capital Resources" section of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "senior debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "senior debt to consolidated present value of total proven 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.

Reconciliation of Net Income to Adjusted EBITDA(1) ($ millions)	**June 30, 2016**
Net income/(loss)	$ (1,259.9)
Add:	
Interest	59.6
Current and deferred tax expense/(recovery)	502.0
DD&A and asset impairment	1,193.4
Other non-cash charges(2)	129.7
Sub-total	$ 624.8
Adjustment for material acquisitions and divestments(3)	(21.6)
Adjusted EBITDA	$ 603.2

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at June 30, 2016 include the six months ended June 30, 2016 and the third and fourth quarters of 2015.
(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.

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, 2016, 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, 2016 and ended June 30, 2016 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, 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 forward-looking statements within the meaning of applicable securities laws ("forward-looking information"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "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 2016 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 funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management programs in 2016 and 2017; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash and non-cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2016 and its impact on our production level and land holdings; potential future asset and goodwill impairments, as well as the 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 cash taxes; our deferred income taxes; future debt and working capital levels and debt to 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 divestments, expected timing thereof, production and reductions in asset retirement obligations associated therewith and use of proceeds therefrom; expected gains for accounting purposes in respect to our repurchase of senior notes and our asset divestments; anticipated amount of interest expense savings in respect to our repurchase of senior notes; 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, expectations and assumptions 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; 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 funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our 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 2016 guidance contained in this MD&A is based on the following: a WTI price of US$42.61/bbl, a NYMEX price of US$2.46/Mcf, an AECO price of $2.00/GJ and a USD/CDN exchange rate of 1.32. We believe 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 decline of 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 and contingencies described under "Risk Factors and Risk Management" in the annual MD&A and in our other public filings).*

The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.