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

The following discussion and analysis of financial results is dated November 5, 2015 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 nine months ended September 30, 2015 and 2014 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2014 and 2013 and for the years ended December 31, 2014, 2013 and 2012; and
- our MD&A for the year ended December 31, 2014 (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" below 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 other 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 interest, unless otherwise stated. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities 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.

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. The term 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 September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Oil and natural gas sales	$ 275.7	$ 456.2	$ 818.2	$ 1,455.8
Less:				
Royalties	(47.4)	(77.9)	(133.2)	(254.8)
Production taxes	(13.9)	(21.3)	(38.9)	(61.1)
Cash operating expenses(1)	(88.6)	(88.8)	(254.8)	(254.9)
Transportation costs	(30.9)	(27.9)	(85.4)	(72.9)
Netback before hedging	$ 94.9	$ 240.3	$ 305.9	$ 812.1
Cash gains/(losses) on derivative instruments	54.1	(2.5)	214.0	(42.4)
Netback after hedging	$ 149.0	$ 237.8	$ 519.9	$ 769.7

(1) Operating costs adjusted to exclude non-cash losses on fixed price electricity swaps of $1.8 million and $0.1 million in the three and nine months ended September 30, 2015 (non-cash gains of nil and $0.2 million in the three and nine months ended September 30, 2014).

"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 provided by 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 September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Cash flow from operating activities	$ 122.6	$ 199.1	$ 388.8	$ 568.0
Asset retirement obligation expenditures	4.2	3.3	10.6	11.8
Changes in non-cash operating working capital	(6.0)	10.4	(9.0)	66.7
Funds Flow	$ 120.8	$ 212.8	$ 390.4	$ 646.5

"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 12 months of funds flow. This measure is not equivalent to Debt to Earnings before Interest, Taxes, Depreciation and Amortization and other non-cash charges ("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 September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Cash dividends(1)	$ 30.9	$ 51.1	$ 109.2	$ 143.8
Capital and office expenditures	89.9	209.2	407.2	633.0
Sub-total	$ 120.8	$ 260.3	$ 516.4	$ 776.8
Funds flow	$ 120.8	$ 212.8	$ 390.4	$ 646.5
Adjusted payout ratio (%)	100%	122%	132%	120%

(1) Cash dividends exclude stock dividend plan proceeds in 2014.

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 EBITDA", "Total Debt to EBITDA", "Total Debt to Capitalization", "maximum debt to consolidated present value of total proven reserves" and "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.

OVERVIEW

We continued to benefit from the momentum of our strong operational performance in the third quarter, while maintaining our balance sheet strength. We have delivered production growth and met or exceeded all of our guidance targets year-to-date. As a result, we are increasing our 2015 annual average production guidance by 4,000 BOE/day from the mid-point, reducing our capital spending guidance by $30 million and reducing our operating cost and general administrative ("G&A") expense guidance by $0.30/BOE, overall.

Production for the third quarter was 110,794 BOE/day, an increase of 3% compared to the second quarter and ahead of our annual average production guidance range of 100,000-104,000 BOE/day. Production increased by 3,365 BOE/day primarily due to additional well on-streams in our core oil play in Fort Berthold, North Dakota, where crude oil production increased by 4,795 BOE/day or 22% compared to the second quarter of 2015. With continued production outperformance in Fort Berthold, we are increasing our 2015 annual production guidance to 106,000 BOE/day and expect approximately 46,000 bbls/day of crude oil and natural gas liquids.

Our capital spending for the third quarter was $88.9 million, down from $148.0 million in the second quarter with most of our spending focused on our core crude oil plays. As a result of continued cost improvements, deferral of spending into 2016 and strong operational performance, we are decreasing our annual capital spending guidance from $540 million to $510 million.

Third quarter funds flow decreased to $120.8 million from $160.4 million in the second quarter as realized oil prices declined during the period. Our commodity price hedges continued to provide funds flow protection with cash gains of $54.1 million recorded during the quarter.

The continued decline in the twelve month average commodity price used to calculate impairments in accordance with U.S. GAAP resulted in a non-cash asset impairment charge of $321.2 million (before tax) in the quarter and $1,086.0 million (before tax) for the nine months ended September 30, 2015. Accordingly, we reported a net loss for the quarter of $292.7 million compared to a net loss of $312.5 million in the second quarter of 2015.

Operating costs for the quarter were in line with expectations at $90.4 million. As expected, we saw an increase in operating costs with seasonal turnaround activity, however on a per BOE basis, operating costs came in below guidance of $9.25/BOE at $8.87/BOE due to higher production. Cash G&A costs were in line with guidance of $2.25/BOE, at $22.8 million or $2.24/BOE, despite one-time severance charges that were incurred in the quarter. As a result of our continued focus on cost reductions and increased production guidance range, we are decreasing our operating cost guidance to $9.00/BOE and our G&A expense guidance to $2.20/BOE.

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, 2018. As part of the extension, we chose to decrease our bank credit facility from $1.0 billion to $800 million after confirming with our syndicate banks that we could have maintained the facility at its current level. This decision balanced the need for sufficient liquidity to execute our business plan with the associated costs of maintaining a largely undrawn bank facility.

Despite the decline in commodity prices during the last year, we have remained in a strong financial position. At September 30, 2015, we had a debt to funds flow ratio of 2.0x and senior debt to EBITDA ratio of 1.8x. After a US$10.8 million senior note repayment in the fourth quarter of 2015 we have no term debt repayments until June of 2017. Subsequent to the quarter, we have taken additional steps to preserve our financial strength. We are reducing our monthly dividend to $0.03 per share from $0.05 per share effective with our December dividend payment. In addition, we have entered into an agreement to sell a portion of our non-operated North Dakota acreage for proceeds of $80 million, bringing our year to date net divestment proceeds to $283.4 million. This divestment represents less than 2% of our overall North Dakota acreage with forecast 2016 production from the existing wells of 1,000 BOE/day. We expect the sale to close during the fourth quarter. As a result of these initiatives, coupled with our continuing operational excellence, we expect to deliver a sustainable and balanced strategy for 2016.

2016 OUTLOOK

Our capital spending guidance for 2016 is $350 million, a decrease of approximately 30% from 2015 guidance of $510 million. With a focus on efficiencies and targeted spending across our core areas, we expect this spending level will allow us to essentially sustain production levels at 100,000-105,000 BOE/day, including 44,000-47,000 bbls/day of crude oil and natural gas liquids.

We expect 2016 operating expenses to average $9.20/BOE, a slight increase from $9.00/BOE in 2015, primarily due to the impact of a weak Canadian dollar on our U.S. dollar denominated operating costs and the marginal decline in production in 2016.

We are providing cash G&A guidance of $1.90/BOE, down $0.30/BOE from 2015 guidance as a result of continued cost savings initiatives and a reduction in staff.

We expect transportation costs of $3.00/BOE and an average royalty and production tax rate of 22%.

RESULTS OF OPERATIONS

Production

Production for the third quarter totaled 110,794 BOE/day, exceeding our guidance range of 100,000-104,000 BOE/day and increasing 3% compared to 107,429 BOE/day in the second quarter of 2015. This increase was driven primarily by oil production in Fort Berthold, which increased 22% or 4,795 BOE/day compared to the prior quarter. Natural gas production levels were consistent with the second quarter, with outperformance in the Marcellus offsetting a decrease in Canadian deep gas production due to scheduled turnarounds at major facilities. As a result, crude oil and natural gas liquids production in the third quarter increased to 45% of our total average daily production, up from 43% in the second quarter of 2015.

Production in the third quarter of 2015 increased 6% from 104,035 BOE/day in the same period of 2014. Crude oil production increased 11% largely due to our ongoing development program in Fort Berthold, which saw a 38% increase in crude oil production compared to the prior year. Over the same period, natural gas production increased by 2%, with growth in our Marcellus production more than offsetting the impact of our disposition of non-core gas weighted properties during the second half of 2014.

Average daily production volumes for the three and nine months ended September 30, 2015 and 2014 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2015**	**2014**	**% Change**	**2015**	**2014**	**% Change**
Crude oil (bbls/day)	44,888	40,332	11%	41,809	39,328	6%
Natural gas liquids (bbls/day)	5,061	3,869	31%	4,652	3,591	30%
Natural gas (Mcf/day)	365,071	359,007	2%	359,611	356,288	1%
Total daily sales (BOE/day)	110,794	104,035	6%	106,396	102,300	4%

As a result of continued outperformance we are revising our average annual production guidance upward to 106,000 BOE/day from 100,000-104,000 BOE/day, with approximately 46,000 bbls/day of crude oil and natural gas liquids. This increase in guidance includes lower projected fourth quarter oil production due to divestments and reduced on-stream activity in Fort Berthold.

In 2016, we expect annual average production of 100,000-105,000 BOE/day, including 44,000-47,000 bbls/day of crude oil and natural gas liquids. We expect this will be achieved despite significantly lower capital spending in 2016 and the fourth quarter sale of a portion of our North Dakota acreage.

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 the nine month period ended September 30, 2015 and 2014 and quarterly average prices from the third quarter of 2014 to the third quarter of 2015:

Pricing (average for the period)	Nine months ended September 30, 2015	Nine months ended September 30, 2014	Q3 2015	Q2 2015	Q1 2015	Q4 2014	Q3 2014
Benchmarks							
WTI crude oil (US$/bbl)	$ 51.00	$ 99.61	$ 46.43	$ 57.94	$ 48.64	$ 73.15	$ 97.17
AECO natural gas – monthly index (CDN$/Mcf)	2.80	4.55	2.80	2.67	2.95	4.01	4.22
AECO natural gas – daily index (CDN$/Mcf)	2.77	4.81	2.90	2.64	2.75	3.60	4.02
NYMEX natural gas – last day (US$/Mcf)	2.80	4.55	2.77	2.64	2.98	4.00	4.06
US/CDN exchange rate	1.26	1.09	1.31	1.23	1.24	1.14	1.09
Enerplus Selling Price(1)							
Crude oil (CDN$/bbl)	$ 50.21	$ 92.55	$ 48.22	$ 58.26	$ 44.04	$ 69.17	$ 88.28
Natural gas liquids (CDN$/bbl)	18.60	54.79	13.51	20.88	22.48	42.34	46.76
Natural gas (CDN$/Mcf)	2.24	4.18	2.08	2.09	2.58	3.25	3.36
Average differentials							
MSW Edmonton – WTI (US$/bbl)	$ (4.43)	$ (7.44)	$ (3.42)	$ (3.06)	$ (6.80)	$ (6.36)	$ (7.93)
WCS Hardisty – WTI (US$/bbl)	(13.20)	(21.12)	(13.27)	(11.59)	(14.73)	(14.24)	(20.18)
Brent Futures (ICE) – WTI (US$/bbl)	5.66	7.40	4.77	5.63	6.58	3.85	6.25
AECO monthly – NYMEX (US$/Mcf)	(0.57)	(0.40)	(0.63)	(0.47)	(0.60)	(0.47)	(0.18)
Enerplus realized differentials(1)							
Canada crude oil – WTI (US$/bbl)	$ (13.33)	$ (19.08)	$ (11.82)	$ (12.50)	$ (15.22)	$ (12.17)	$ (20.51)
Canada natural gas – NYMEX (US$/Mcf)	(0.45)	(0.26)	(0.43)	(0.46)	(0.46)	(0.62)	(0.29)
Bakken crude oil – WTI (US$/bbl)	(9.84)	(11.89)	(8.52)	(9.30)	(11.65)	(12.15)	(12.81)
Marcellus natural gas – NYMEX (US$/Mcf)	(1.46)	(1.36)	(1.64)	(1.39)	(1.32)	(1.62)	(1.70)

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

Crude Oil and Natural Gas Liquids

WTI crude oil prices fell by 20% versus the previous quarter to average US$46.43/bbl during the third quarter. Crude oil supply continued to exceed global demand. The agreement reached early in the quarter that allowed for increased Iranian crude oil exports and other sanctions relief in exchange for increased inspections and monitoring of the Iranian nuclear program exacerbated market concerns over the supply-demand imbalance, pushing oil prices sharply lower. The sell-off in crude was also driven by concerns over China's economy and the considerable losses realized in their stock market over the summer. This pushed WTI prices down to a low of US$38.24/bbl before stabilizing at approximately US$45.00/bbl by the end of the quarter.

The weakness in WTI prices and differentials was offset by a significantly weaker US/CDN dollar exchange rate. Our realized crude oil price declined by approximately 17% to average $48.22/bbl during the third quarter. The heavy crude oil differential tightened to US$7.44/bbl below WTI in July due to the impact of production outages in Northern Alberta and then widened to US$18.97/bbl as a result of a major Midwest U.S. refinery fire in late August. Light sweet crude oil price differentials experienced similar volatility due to unplanned refinery outages resulting in Canadian light sweet differentials being slightly weaker than in the second quarter averaging US$3.42/bbl below WTI.

We saw improvement in our U.S. Bakken crude oil differential during the third quarter as U.S. oil production has started to decline. Our realized Bakken differential was US$8.52/bbl below WTI compared to US$9.30/bbl below WTI in the second quarter. Subsequent to the third quarter we have seen differentials improve further. For 2016, we expect a Bakken differential of US$8.00/bbl below WTI.

The decline in crude oil prices plus the continued build in natural gas liquids inventories in the U.S. pushed benchmark prices for liquids lower once again during the third quarter. Propane stocks increased by over 9 million barrels, sending U.S. benchmark propane prices significantly lower. Propane prices in Canada continued to trade negative during the third quarter as a result of the oversupply of propane in the Canadian market. Prices for condensate in both the U.S. and Canada were also lower this quarter due to the 20% decline in WTI prices. As a result, we realized an average price for our natural gas liquids of $13.51/bbl which is a 35% decrease from the second quarter.

Natural Gas

Natural gas prices at AECO (monthly) and on the NYMEX were slightly stronger during the third quarter, both averaging 5% higher than the previous quarter. Natural gas in storage in the U.S. at September 30, 2015 was 3.6 Tcf, which is near the highest level we have seen at this time of the year relative to the past five years, and remains on track to reach 4.0 Tcf. Mild temperatures and ongoing concerns over the impact a strong El Nino weather pattern may have on natural gas demand this winter has driven current NYMEX prices lower. Our realized natural gas price in the third quarter of 2015 averaged $2.08/Mcf, which was largely unchanged from the previous quarter with weaker Marcellus differentials offsetting the strength in AECO and NYMEX prices.

Strong production levels and significant maintenance activities on the two major pipelines running through Northeast Pennsylvania contributed to continued weakness in regional Marcellus pricing during the quarter. Transco Leidy Pipeline and Tennessee Gas Pipeline Marcellus spot prices averaged US$1.71/Mcf below NYMEX. As we continue to have a significant portion of our Marcellus production linked to markets outside of the production region, our realized Marcellus gas price averaged US$1.64/Mcf below NYMEX. This was 18% lower than the second quarter. Basis differentials have improved subsequent to the quarter-end in the region, with spot prices in the Marcellus trading approximately US$1.00/Mcf to US$1.50/Mcf below NYMEX, due to weaker NYMEX prices and the recent tie-in of new regional export pipeline capacity. For 2016, we expect a Marcellus differential of US$1.25/Mcf below NYMEX.

Foreign Exchange

The Canadian dollar weakened during the third quarter, averaging US/CDN 1.31. In July, we saw the Canadian dollar fall to a six year low of 1.30 following the Bank of Canada's decision to cut interest rates by 25 basis points and lower their forecasted economic growth for 2015. The Canadian dollar continued to depreciate in August and September as a result of decreasing commodity prices, exiting the quarter at a US/CDN exchange rate of 1.34; a level not experienced since 2004. The majority of our crude oil and natural gas sales are based on U.S. dollar denominated indices and a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. Because we report in Canadian dollars, the weaker Canadian dollar also increases our U.S. dollar denominated operating costs, capital spending and the principal and interest on our U.S. dollar denominated senior notes.

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. Hedging activity was minimal during the third quarter due to the current commodity price environment. For the fourth quarter of 2015, we have an average of 14,500 bbls/day of crude oil (approximately 45% of our expected crude oil production, net of royalties) hedged at an average floor price of US$79.47/bbl through a combination of swaps and three-way collar structures. In 2016 we have an average of 11,000 bbls/day of crude oil (approximately 34% of our expected crude oil production, net of royalties) hedged at an average floor price of US$64.35/bbl through a combination of swaps and three-way collar structures.

We have not added materially to our gas hedging program with prices remaining weak during the quarter. For the fourth quarter of 2015 we are swapped on an average of 101,739 Mcf/day (approximately 36% of our forecasted natural gas production, net of royalties) at an average price of US$3.97/Mcf. In 2016 we have 25,000 Mcf/day (approximately 9% of our forecasted natural gas production, net of royalties) hedged through three-way collars with an average floor price of US$3.00/Mcf.

The following is a summary of our financial contracts in place at October 22, 2015 expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)[1]			NYMEX Natural Gas (US$/Mcf)[1]		
	Oct 1, 2015 – Dec 31, 2015	Jan 1, 2016 – Jun 30, 2016	Jul 1, 2016 – Dec 31, 2016	Oct 1, 2015 – Oct 31, 2015	Nov 1, 2015 – Dec 31, 2015	Jan 1, 2016 – Dec 31, 2016
Downside Protection – Swaps						
Sold Swaps	$ 82.10	$ 64.28	–	$ 3.85	$ 4.04	–
%	39%	9%	–	41%	34%	–
Downside Protection – Collars						
Sold Puts	$ 48.00	$ 50.13	$ 49.34	–	–	$ 2.50
%	6%	25%	34%	–	–	9%
Purchased Puts	$ 63.00	$ 64.38	$ 64.35	–	–	$ 3.00
%	6%	25%	34%	–	–	9%
Sold Calls	$ 70.00	$ 79.38	$ 80.09	–	–	$ 3.75
%	6%	25%	34%	–	–	9%
Upside Participation Collars						
Sold Puts	$ 62.23	–	–	$ 3.25	$ 3.25	–
%	12%	–	–	2%	2%	–
Purchased Calls	$ 93.00	–	–	$ 4.29	$ 4.29	–
%	12%	–	–	2%	2%	–
Sold Calls	–	–	–	$ 5.00	$ 5.00	–
%	–	–	–	2%	2%	–

(1) Based on weighted average price (before premiums), assumed average annual production of 106,000 BOE/day for 2015 and 100,000 – 105,000 BOE/day for 2016, less royalties and production taxes of 21.0% and 22.0% in aggregate, respectively.

We have also entered into WCS and MSW differential swap positions to manage our exposure to Canadian crude oil differentials. At October 22, 2015, we have 4,000 bbls/day of WCS swapped at US$(16.61)/bbl and 1,333 bbls/day of MSW swapped at US$(3.28)/bbl for the fourth quarter of 2015. For 2016, we have 3,000 bbls/day of WCS swapped at US$(14.03)/bbl and 1,000 bbls/day of MSW swapped at US$(3.50)/bbl.

The following table provides a summary of the physical AECO-NYMEX basis contracts we have in place at October 22, 2015:

	MMcf/day	US$/Mcf
Oct 1, 2015 – Oct 31, 2015 AECO-NYMEX Basis	60.0	$ (0.65)
Nov 1, 2015 – Oct 31, 2016 AECO-NYMEX Basis	60.0	$ (0.67)
Nov 1, 2016 – Oct 31, 2017 AECO-NYMEX Basis	80.0	$ (0.65)
Nov 1, 2017 – Oct 31, 2018 AECO-NYMEX Basis	80.0	$ (0.65)
Nov 1, 2018 – Oct 31, 2019 AECO-NYMEX Basis	80.0	$ (0.64)

In 2014 we entered into foreign exchange collars on US$24 million per month to hedge a floor exchange rate on a portion of our U.S. dollar denominated oil and natural gas sales with upside participation in the event the Canadian dollar weakened. During the second quarter of 2015 we entered into U.S. dollar forward exchange contracts on US$6 million per month at an exchange rate of US/CDN 1.20 to partially mitigate our losses on these collars. As of October 22, 2015, we effectively have US$18 million per month hedged for 2015 at an average US/CDN floor of

1.1088, a ceiling of 1.1845 and a conditional ceiling of 1.1263. Under these contracts, if the monthly foreign exchange rate settles above the ceiling rate the conditional celling is used to determine the settlement amount. We do not have any foreign exchange contracts in place for 2016.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses) ($ millions)	**Three months ended September 30, 2015**	**2014**	**Nine months ended September 30, 2015**	**2014**
Cash gains/(losses):				
Crude oil	$ 36.6	$ (4.2)	$ 163.8	$ (36.2)
Natural gas	17.5	1.7	50.2	(6.2)
Total cash gains/(losses)	$ 54.1	$ (2.5)	$ 214.0	$ (42.4)
Non-cash gains/(losses):				
Change in fair value – crude oil	$ 35.1	$ 82.9	$ (71.9)	$ 48.7
Change in fair value – natural gas	(8.2)	10.9	(30.4)	8.3
Total non-cash gains/(losses)	$ 26.9	$ 93.8	$ (102.3)	$ 57.0
Total gains	$ 81.0	$ 91.3	$ 111.7	$ 14.6

(Per BOE)	**Three months ended September 30, 2015**	**2014**	**Nine months ended September 30, 2015**	**2014**
Total cash gains/(losses)	$ 5.31	$ (0.26)	$ 7.36	$ (1.52)
Total non-cash gains/(losses)	2.64	9.80	(3.52)	2.04
Total gains	$ 7.95	$ 9.54	$ 3.84	$ 0.52

During the third quarter of 2015 we realized cash gains of $36.6 million on our crude oil contracts and $17.5 million on our natural gas contracts. In comparison, during the third quarter of 2014 we realized cash losses of $4.2 million on our crude oil contracts and cash gains of $1.7 million on our natural gas contracts. The cash gains in 2015 were due to contracts which provided floor protection above market prices, while cash losses in 2014 were a result of prices rising above our fixed price swap positions.

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 third quarter of 2015 the fair value of our crude oil and natural gas contracts represented net gain positions of $95.3 million and $18.8 million, respectively. For the three and nine months ended September 30, 2015 the change in the fair value of our crude oil contracts represented gains of $35.1 million and losses of $71.9 million, respectively, and our natural gas contracts represented losses of $8.2 million and $30.4 million, respectively.

During the three and nine months ended September 30, 2015 we recorded total cash losses on our foreign exchange collars of $10.9 million and $26.6 million, respectively. At September 30, 2015 the fair value of foreign exchange derivatives was a net loss of $9.2 million. See Note 15 for further information.

Revenues

($ millions)	**Three months ended September 30, 2015**	**2014**	**Nine months ended September 30, 2015**	**2014**
Oil and natural gas	$ 275.7	$ 456.2	$ 818.2	$ 1,455.8
Royalties	(47.4)	(77.9)	(133.2)	(254.8)
Oil and natural gas sales, net of royalties	$ 228.3	$ 378.3	$ 685.0	$ 1,201.0

Oil and natural gas revenues for the three and nine months ended September 30, 2015 were $228.3 million and $685.0 million, respectively, compared to $378.3 million and $1,201.0 million for the same periods in 2014. The decrease in revenue for both the three and nine month periods was driven primarily by the weak commodity price environment offset somewhat by an increase in production volumes.

Royalties and Production Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2015	2014	2015	2014
Royalties	$ 47.4	$ 77.9	$ 133.2	$ 254.8
Per BOE	$ 4.65	$ 8.14	$ 4.59	$ 9.12
Production taxes	$ 13.9	$ 21.3	$ 38.9	$ 61.1
Per BOE	$ 1.36	$ 2.22	$ 1.34	$ 2.19
Royalties and production taxes	$ 61.3	$ 99.2	$ 172.1	$ 315.9
Per BOE	$ 6.01	$ 10.36	$ 5.93	$ 11.31
Royalties and production taxes (% of oil and natural gas sales, before transportation)	22%	22%	21%	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. During the three and nine months ended September 30, 2015 royalties and production taxes decreased to $61.3 million and $172.1 million, respectively, from $99.2 million and $315.9 million for the same periods in 2014, primarily due to lower realized prices. Royalties and production taxes as a percentage of oil and natural gas sales before transportation averaged 22% and 21% for the three and nine months ended September 30, 2015, respectively, compared to 22% for the same periods in 2014.

We continue to expect an average royalty and production tax rate of 21% in 2015 with a slight increase to 22% in 2016 as a result of increased U.S. production with a higher effective royalty and production tax rate.

Operating Expenses

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2015	2014	2015	2014
Operating expenses	$ 90.4	$ 88.9	$ 254.9	$ 254.7
Per BOE	$ 8.87	$ 9.28	$ 8.77	$ 9.12

Effective January 1, 2015 we reclassified Marcellus gathering costs from operating expenses to transportation costs. These charges relate to pipeline costs paid to third parties to transport saleable natural gas from the lease to downstream points of sale. This is a presentation change with no impact on our netback, funds flow or net income. All comparative periods have been presented to conform to the current period presentation.

For the three and nine months ended September 30, 2015 operating expenses were $90.4 million or $8.87/BOE and $254.9 million or $8.77/BOE, respectively, compared to $88.9 million or $9.28/BOE and $254.7 million or $9.12/BOE for the same periods in 2014. As expected, our third quarter 2015 operating costs increased over the previous quarter as a result of planned maintenance activity, the impact of a weakening Canadian dollar on our U.S. dollar denominated operating expenses and non-cash losses of $1.8 million on our electricity hedges. Overall, operating costs per BOE decreased during the three and nine months ended September 30, 2015 compared to the prior year due to higher production volumes and realized cost saving initiatives, offset in part by the impact of a weaker Canadian dollar.

Based on our cost savings to date and our increased production guidance, we are reducing our 2015 guidance for operating expenses to $9.00/BOE from $9.25/BOE. Although year to date operating costs are below our revised guidance, we are expecting oil production to decrease in the fourth quarter as a result of reduced on-stream activity in Fort Berthold and our fourth quarter divestment.

For 2016, we expect operating costs to average $9.20/BOE, a slight increase from 2015 operating costs per BOE. This is primarily due to the full year impact of a US/CDN exchange rate of 1.33 and a marginal decline in production in 2016.

Transportation Costs

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2015	2014	2015	2014
Transportation costs	$ 30.9	$ 27.9	$ 85.4	$ 72.9
Per BOE	$ 3.03	$ 2.92	$ 2.94	$ 2.61

As discussed previously in operating expenses, we have reclassified Marcellus gathering costs to transportation costs. This is a presentation change with no impact on our netback, funds flow or net income. All comparative periods have been presented to conform with the current period presentation.

For the three and nine months ended September 30, 2015 transportation costs were $30.9 million or $3.03/BOE and $85.4 million or $2.94/BOE, respectively, compared to $27.9 million or $2.92/BOE and $72.9 million or $2.61/BOE for the same periods in 2014. The increase in transportation costs was due to higher U.S. production and the impact of a weakening Canadian dollar on our U.S. dollar denominated costs.

We are maintaining our annual transportation cost guidance of $3.00/BOE for 2015 and 2016.

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. Certain prior period amounts have been reclassified to conform with current period presentations.

	Three months ended September 30, 2015		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	52,764 BOE/day	348,180 Mcfe/day	110,794 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 43.34	$ 2.04	$ 27.04
Royalties and production taxes	(11.02)	(0.24)	(6.01)
Cash operating expenses	(11.48)	(1.03)	(8.69)
Transportation costs	(1.74)	(0.70)	(3.03)
Netback before hedging	$ 19.10	$ 0.07	$ 9.31
Cash gains/(losses)	7.53	0.55	5.31
Netback after hedging	$ 26.63	$ 0.62	$ 14.62
Netback before hedging ($ millions)	$ 92.7	$ 2.2	$ 94.9
Netback after hedging ($ millions)	$ 129.2	$ 19.8	$ 149.0

Netbacks by Property Type	Three months ended September 30, 2014 Crude Oil	Natural Gas	Total
Average Daily Production	45,263 BOE/day	352,632 Mcfe/day	104,035 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 77.98	$ 4.06	$ 47.67
Royalties and production taxes	(20.73)	(0.40)	(10.36)
Cash operating expenses	(9.05)	(1.58)	(9.29)
Transportation costs	(1.91)	(0.62)	(2.92)
Netback before hedging	$ 46.29	$ 1.46	$ 25.10
Cash gains/(losses)	(1.01)	0.05	(0.26)
Netback after hedging	$ 45.28	$ 1.51	$ 24.84
Netback before hedging ($ millions)	$ 192.8	$ 47.5	$ 240.3
Netback after hedging ($ millions)	$ 188.6	$ 49.2	$ 237.8

Netbacks by Property Type	Nine months ended September 30, 2015 Crude Oil	Natural Gas	Total
Average Daily Production	48,930 BOE/day	344,796 Mcfe/day	106,396 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 45.62	$ 2.22	$ 28.17
Royalties and production taxes	(10.99)	(0.27)	(5.93)
Cash operating expenses	(11.99)	(1.00)	(8.77)
Transportation costs	(1.79)	(0.65)	(2.94)
Netback before hedging	$ 20.85	$ 0.30	$ 10.53
Cash gains/(losses)	12.26	0.53	7.36
Netback after hedging	$ 33.11	$ 0.83	$ 17.89
Netback before hedging ($ millions)	$ 278.4	$ 27.5	$ 305.9
Netback after hedging ($ millions)	$ 442.2	$ 77.7	$ 519.9

Netbacks by Property Type	Nine months ended September 30, 2014 Crude Oil	Natural Gas	Total
Average Daily Production	44,317 BOE/day	347,898 Mcfe/day	102,300 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 84.58	$ 4.55	$ 52.13
Royalties and production taxes	(21.08)	(0.64)	(11.31)
Cash operating expenses	(11.38)	(1.23)	(9.14)
Transportation costs	(1.80)	(0.54)	(2.61)
Netback before hedging	$ 50.32	$ 2.14	$ 29.07
Cash gains/(losses)	(2.99)	(0.07)	(1.52)
Netback after hedging	$ 47.33	$ 2.07	$ 27.55
Netback before hedging ($ millions)	$ 608.9	$ 203.2	$ 812.1
Netback after hedging ($ millions)	$ 572.7	$ 197.0	$ 769.7

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

Our crude oil properties accounted for 91% of our corporate netback before hedging for the nine months ended September 30, 2015 compared to 75% for the same period in 2014. Crude oil and natural gas netbacks per BOE decreased significantly for the three and nine months ended September 30, 2015 compared to the same periods in 2014 primarily due to the decline in commodity prices. Realized cash hedging gains along with lower royalty rates and lower operating expenses helped to offset the impact of lower prices.

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 for further details.

($ millions)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Cash:				
G&A expense	$ 22.8	$ 18.9	$ 64.1	$ 58.1
Share-based compensation	(3.6)	(5.2)	2.5	12.3
Non-Cash:				
Share-based compensation	7.8	3.4	17.4	9.9
Equity swap loss/(gain)	2.0	5.8	1.4	(0.1)
Total G&A expenses	$ 29.0	$ 22.9	$ 85.4	$ 80.2

(Per BOE)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Cash:				
G&A expense	$ 2.24	$ 1.97	$ 2.21	$ 2.08
Share-based compensation	(0.35)	(0.54)	0.08	0.44
Non-Cash:				
Share-based compensation	0.77	0.36	0.60	0.35
Equity swap loss/(gain)	0.19	0.61	0.05	–
Total G&A expenses	$ 2.85	$ 2.40	$ 2.94	$ 2.87

Cash G&A expenses during the three and nine months ended September 30, 2015 were $22.8 million ($2.24/BOE) and $64.1 million ($2.21/BOE), respectively, compared to $18.9 million ($1.97/BOE) and $58.1 million ($2.08/BOE) for the same periods in 2014. The increase in cash G&A expenses compared to 2014 were a result of one-time severance payments of $8.5 million or $0.29/BOE year to date offset by cost savings.

During the quarter, our share price decreased by 41% resulting in a cash SBC recovery of $3.6 million or $0.35/BOE compared to a recovery of $5.2 million or $0.54/BOE in the same period of 2014. We recorded non-cash SBC of $7.8 million or $0.77/BOE in the third quarter compared to $3.4 million or $0.36/BOE during the same period in 2014. The increase in non-cash SBC was a result of additional grants issued under the LTI plans, along with one-time severance charges.

We have hedged a portion of the outstanding cash settled grants under our LTI plans. As a result of the decrease in our share price during the quarter we recorded a non-cash mark-to-market loss of $2.0 million on these hedges. As of September 30, 2015 we had 470,000 units hedged at a weighted average price of $16.89 per share.

As a result of cost savings realized to date, we are reducing our cash G&A guidance to $2.20/BOE from $2.25/BOE. We do not provide guidance for SBC because it is dependent on our share price and our relative performance to our peers.

For 2016, we are providing cash G&A guidance of $1.90/BOE, down $0.30/BOE or 14% from 2015 guidance as a result of staff reductions and ongoing cost savings efforts.

Interest Expense

($ millions)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Interest on senior notes and bank facility	$ 16.3	$ 14.9	$ 48.9	$ 45.5
Non-cash interest expense	0.2	0.3	0.8	1.4
Total interest expense	$ 16.5	$ 15.2	$ 49.7	$ 46.9

For the three and nine months ended September 30, 2015 we recorded total interest expense of $16.5 million and $49.7 million, respectively, compared to $15.2 million and $46.9 million for the same periods in 2014. The increase in interest expense for the three and nine month period was primarily due to the impact of a weakening Canadian dollar on our U.S. dollar denominated interest expense, along with an overall increase in senior notes with higher interest rates compared to our bank credit facility following our September 2014 private placement of US$200 million.

Non-cash amounts recorded in interest expense include amortization of deferred financing charges. See Note 11 for further details.

At September 30, 2015 approximately 91% of our debt was based on fixed interest rates and 9% on floating interest rates, with weighted average interest rates of 5.2% and 2.4%, respectively.

Foreign Exchange

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2015	2014	2015	2014
Realized loss/(gain)	$ 8.8	$ (2.6)	$ (18.4)	$ 14.0
Unrealized loss/(gain)	60.8	33.1	164.6	10.7
Total foreign exchange loss/(gain)	$ 69.6	$ 30.5	$ 146.2	$ 24.7
US/CDN exchange rate	1.31	1.09	1.26	1.09

For the three and nine months ended September 30, 2015 we recorded net foreign exchange losses of $69.6 million and $146.2 million, respectively, compared to losses of $30.5 million and $24.7 million for the same periods in 2014.

Realized losses of $8.8 million in the third quarter included net payments of $10.9 million on our foreign exchange collars and forward contracts offset by gains on day-to-day transactions recorded in foreign currencies. During the nine months ended September 30, 2015 we recorded realized gains of $18.4 million primarily due to a $39.9 million gain on the unwind of our US$175 million foreign exchange swaps during the first quarter which were offset by cumulative losses of $26.6 million on our foreign exchange collars caused by a continued weakening of the Canadian dollar.

Unrealized losses include the translation of U.S. dollar debt and working capital as well as changes in fair value of our foreign exchange derivatives. See Note 12 for further details.

Capital Investment

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2015	2014	2015	2014
Capital spending	$ 88.9	$ 207.8	$ 403.9	$ 630.0
Office capital	1.0	1.4	3.3	3.0
Sub-total	89.9	209.2	407.2	633.0
Property and land acquisitions	$ 2.0	$ 4.0	$ 0.8	$ 17.2
Property divestments	(11.9)	(68.9)	(203.4)	(185.6)
Sub-total	(9.9)	(64.9)	(202.6)	(168.4)
Total	$ 80.0	$ 144.3	$ 204.6	$ 464.6

Capital spending for the three and nine months ended September 30, 2015 totaled $88.9 million and $403.9 million, respectively, compared to $207.8 million and $630.0 million for the same periods in 2014. Although we slowed spending due to weak commodity prices, we continued to invest modestly in our core areas. During the third quarter we spent $58.1 million on our Fort Berthold crude oil properties, $23.9 million on our Canadian crude oil properties, $3.3 million on our Marcellus assets and $2.8 million on our deep gas properties in Canada.

We disposed of non-core Canadian oil properties in Southeast Saskatchewan during the third quarter for proceeds of $11.9 million. In the third quarter of 2014 we divested of $68.9 million of non-core natural gas properties in the deep basin area with production of approximately 1,900 BOE/day.

Subsequent to the quarter end, we entered into an agreement to sell a portion of our non-operated North Dakota properties for proceeds of $80 million. This divestment represents less than 2% of our total North Dakota acreage with forecast 2016 production from the existing wells of 1,000 BOE/day. We expect it to close during the fourth quarter. Including this sale, we have recorded year to date net divestment proceeds of $283.4 million.

Due to continued cost improvements, strong operational performance and the deferral of spending into 2016, we have reduced our 2015 guidance for capital spending to $510 million from $540 million.

For 2016, we expect capital spending to be $350 million with approximately 90% directed to oil and liquids properties. As a result of continued cost savings and efficiencies, we expect this lower capital spending budget will allow us to essentially sustain our 2015 production levels through targeted spending across our core areas, while preserving our balance sheet.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2015	2014	2015	2014
DDA&A expense	$ 131.5	$ 159.7	$ 401.3	$ 440.5
Per BOE	$ 12.90	$ 16.68	$ 13.81	$ 15.77

DDA&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, 2015, DDA&A per BOE decreased when compared the same periods of 2014 primarily due to additional reserves recognized in the 2014 year-end reserves evaluation and the effect of the year to date 2015 impairments on our book value.

Impairment

Under U.S. GAAP, entities using full cost oil and gas accounting are subject to a ceiling test performed on a country by country basis using estimated after-tax future net cash flows discounted at 10% 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 reversible in future periods.

The trailing twelve month average crude oil and natural gas prices have decreased significantly over the first three quarters of 2015 and resulted in non-cash impairments for the three and nine months ended September 30, 2015 of $321.2 million and $1,086.0 million (before tax), respectively. We did not record any ceiling test impairments on our oil and natural gas properties in 2014. We expect the twelve month trailing prices used in the ceiling test calculation to decline further which may lead to additional impairments of our oil and natural gas properties. See Note 5 for trailing twelve month prices and additional information.

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 estimated by Enerplus based on our net ownership interest, anticipated 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 $286.0 million at September 30, 2015 compared to $288.7 million at December 31, 2014. The decrease is primarily due to the Pembina property divestment in the second quarter of 2015. Asset retirement obligation settlements for the three and nine months ended September 30, 2015 totaled $4.2 million and $10.6 million, respectively, compared to $3.3 million and $11.8 million for the same periods in 2014. See Note 8 for further information.

Income Taxes

($ millions)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Current tax expense/(recovery)	$ (16.2)	$ –	$ (16.2)	$ 11.4
Deferred tax expense/(recovery)	(84.9)	36.9	(445.0)	74.1
Total tax expense/(recovery)	$ (101.1)	$ 36.9	$ (461.2)	$ 85.5

We recorded a total tax recovery of $101.1 million and $461.2 million for the three and nine months ended September 30, 2015, respectively, compared to an expense of $36.9 million and $85.5 million for the same periods in 2014. The decrease in total tax expense is due primarily to lower income in 2015 which includes non-cash ceiling test impairments for Canada and the U.S. This results in an overall net deferred income tax asset of $793.6 million as at September 30, 2015. We expect to have sufficient future taxable income in both the U.S. and Canada to realize the benefit of this asset.

The current tax recovery of $16.2 million for the nine months ended September 30, 2015 increased in comparison to the $11.4 million expense that was recorded for the same period in 2014. This recovery primarily relates to an expected Alternative Tax Net Operating Loss in the U.S., which we plan to carry-back to recover Alternative Minimum Tax that was previously paid in 2013 and 2014.

These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisition and divestment activity.

SELECTED QUARTERLY CANADIAN AND U.S. FINANCIAL RESULTS

(CDN$ millions, except per unit amounts)	Three months ended September 30, 2015 Canada	U.S.	Total	Three months ended September 30, 2014 Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	14,478	30,410	44,888	16,837	23,495	40,332
Natural gas liquids (bbls/day)	1,731	3,330	5,061	2,578	1,291	3,869
Natural gas (Mcf/day)	131,644	233,427	365,071	154,855	204,152	359,007
Total average daily production (BOE/day)	38,150	72,644	110,794	45,224	58,811	104,035
Pricing(2)						
Crude oil (per bbl)	$ 45.31	$ 49.60	$ 48.22	$ 83.50	$ 91.71	$ 88.28
Natural gas liquids (per bbl)	25.31	7.37	13.51	46.45	47.39	46.76
Natural gas (per Mcf)	3.07	1.53	2.08	4.10	2.79	3.36
Capital expenditures						
Capital spending	$ 29.4	$ 59.5	$ 88.9	$ 55.2	$ 152.6	$ 207.8
Acquisitions	0.9	1.1	2.0	2.0	2.0	4.0
Divestments	(11.8)	(0.1)	(11.9)	(68.9)	–	(68.9)
Netback(4) Before Hedging						
Oil and natural gas sales	$ 101.8	$ 173.9	$ 275.7	$ 199.3	$ 256.9	$ 456.2
Royalties	(11.8)	(35.6)	(47.4)	(27.1)	(50.8)	(77.9)
Production taxes	(1.3)	(12.6)	(13.9)	(2.5)	(18.8)	(21.3)
Cash operating expenses	(55.9)	(32.7)	(88.6)	(64.7)	(24.1)	(88.8)
Transportation costs	(5.4)	(25.5)	(30.9)	(6.2)	(21.7)	(27.9)
Netback before hedging	$ 27.4	$ 67.5	$ 94.9	$ 98.8	$ 141.5	$ 240.3
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (81.0)	$ –	$ (81.0)	$ (91.3)	$ –	$ (91.3)
General and administrative expense(3)	23.9	5.1	29.0	19.8	3.1	22.9
Current tax expense/(recovery)	–	(16.2)	(16.2)	(0.1)	0.1	–

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) Includes share-based compensation.
(4) See "Non-GAAP Measures" section in this MD&A.

(CDN$ millions, except per unit amounts)	Nine months ended September 30, 2015 Canada	U.S.	Total	Nine months ended September 30, 2014 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	15,629	26,180	41,809	16,867	22,461	39,328
Natural gas liquids (bbls/day)	2,073	2,579	4,652	2,531	1,060	3,591
Natural gas (Mcf/day)	137,270	222,341	359,611	154,306	201,982	356,288
Total average daily production (BOE/day)	40,580	65,816	106,396	45,116	57,184	102,300
Pricing[2]						
Crude oil (per bbl)	$ 47.41	$ 51.89	$ 50.21	$ 88.12	$ 95.88	$ 92.55
Natural gas liquids (per bbl)	29.59	9.77	18.60	57.54	48.24	54.79
Natural gas (per Mcf)	2.95	1.80	2.24	4.69	3.78	4.18
Capital expenditures						
Capital spending	$ 131.0	$ 272.9	$ 403.9	$ 243.2	$ 386.8	$ 630.0
Acquisitions	2.9	(2.1)	0.8	2.0	15.2	17.2
Divestments	(199.9)	(3.5)	(203.4)	(136.6)	(49.0)	(185.6)
Netback[4] Before Hedging						
Oil and natural gas sales	$ 330.4	$ 487.8	$ 818.2	$ 645.3	$ 810.5	$ 1,455.8
Royalties	(35.8)	(97.4)	(133.2)	(96.2)	(158.6)	(254.8)
Production taxes	(4.0)	(34.9)	(38.9)	(6.4)	(54.7)	(61.1)
Cash operating expenses	(162.3)	(92.5)	(254.8)	(189.1)	(65.8)	(254.9)
Transportation costs	(17.4)	(68.0)	(85.4)	(17.9)	(55.0)	(72.9)
Netback before hedging	$ 110.9	$ 195.0	$ 305.9	$ 335.7	$ 476.4	$ 812.1
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (111.7)	$ –	$ (111.7)	$ (14.6)	$ –	$ (14.6)
General and administrative expense[3]	66.6	18.8	85.4	65.7	14.5	80.2
Current tax expense/(recovery)	(0.4)	(15.8)	(16.2)	(0.5)	11.9	11.4

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) Includes share-based compensation.
(4) See "Non-GAAP Measures" section in this MD&A.

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
2015				
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	$ 685.0	$ (898.4)	$ (4.36)	$ (4.36)
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
2013				
Fourth Quarter	$ 332.4	$ 29.6	$ 0.15	$ 0.15
Third Quarter	365.4	(3.7)	(0.02)	(0.02)
Second Quarter	341.3	38.5	0.19	0.19
First Quarter	313.4	(16.4)	(0.08)	(0.08)
Total 2013	$ 1,352.5	$ 48.0	$ 0.24	$ 0.24

Oil and natural gas sales decreased during the third quarter compared to the second quarter of 2015 as commodity prices weakened, offset by increasing production. From the first quarter of 2013, oil and natural gas sales increased steadily until the third quarter of 2014 when realized commodity prices began to decline significantly. Net losses incurred during 2015 have been due to asset impairments related to the decrease in the trailing twelve month average commodity prices. We did not record any asset impairments in 2013 or 2014.

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, which is a senior debt to EBITDA threshold of 3.5x for a period of up to six months, after which it drops to 3.0x. At September 30, 2015, our senior debt to EBITDA ratio was 1.8x 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.

Our working capital deficiency, excluding cash and current deferred financial and tax balances, decreased to $135.2 million at September 30, 2015 from $260.5 million at December 31, 2014. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by funds flow, was 100% and 132% for the three and nine months ended September 30, 2015, respectively, compared to 122% and 120% for the same periods in 2014. We have continued to maintain our financial flexibility through an ongoing focus on cost efficiencies, the success of our non-core asset divestment program, disciplined capital spending and a reduction in dividends. After adjusting for net acquisition and divestment proceeds, our adjusted payout ratio for the three and nine months ended September 30, 2015 decreases to 92% and 80%, respectively.

Subsequent to the quarter end, we have taken additional steps to preserve our balance sheet strength. We have entered into an agreement to sell a portion of our non-operated North Dakota acreage for proceeds of $80 million. In addition, we are further reducing our monthly dividend to $0.03 per share from $0.05 per share, effective with our December 2015 payment. We expect to save approximately $50 million annually with the reduction. These initiatives, coupled with our continuing operational success, will allow us to execute our sustainable strategy for 2016.

Total debt, net of cash, at September 30, 2015 was $1,226.5 million compared to $1,134.9 million at December 31, 2014. Total debt was comprised of $113.5 million of bank indebtedness and $1,115.9 million of senior notes less $2.9 million in cash. At September 30, 2015, we were approximately 11% drawn on our $1.0 billion bank credit facility. The majority of the increase in our reported debt balance at September 30, 2015 was a result of the impact of a weakening Canadian dollar on our U.S. dollar denominated senior notes. On October 1, 2015, we paid the final installment of US$10.8 million on our maturing US$54 million senior notes. We have no additional scheduled debt repayments until June of 2017, with remaining maturities extending to 2026.

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, 2018. As part of the extension, we chose to decrease our bank credit facility to $800.0 million from $1.0 billion based on our capital spending plan for 2016 and our ongoing cost reduction initiatives. Our decision balanced the need for sufficient liquidity for executing our business plan with the associated costs of retaining a largely undrawn bank facility. We expect to realize savings of approximately $1.0 million as a result of the decreased facility size. With over 90% of our total debt comprised of term debt with no repayments until 2017 and an average drawn balance of approximately 9% of the current available capacity on our bank credit facility, we are of the view that the $1.0 billion limit provided excess capacity that is not currently required by the Company. Given our reduced 2016 capital spending plan, we intend to maintain our balance sheet strength by balancing capital spending and dividends with funds flow and non-core asset divestments as we continue to focus our portfolio. Our renewed credit facility also amends the maximum Total Debt to Capitalization ratio to 55%. Drawn fees on the facility range between 150 and 315 basis points over Banker's Acceptance rates, with current drawn fees of 170 basis points. The bank credit facility ranks equally with our senior, unsecured, covenant-based notes.

At September 30, 2015, 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, 2015:

Covenant Description		September 30, 2015
Bank Credit Facility:	**Maximum Ratio**	
Senior Debt to EBITDA	3.5 x	1.8 x
Total Debt to EBITDA	4.0 x	1.8 x
Total Debt to Capitalization(1)	50% – 55%	32%
Senior Notes:	**Maximum Ratio**	
Senior Debt to EBITDA(2)	3.0 x – 3.5 x	1.8 x
Maximum debt to consolidated present value of total proven reserves	60%	40%
	Minimum Ratio	
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.

"EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, accretion and non-cash gains and losses. EBITDA is calculated on a trailing twelve month basis and is adjusted for material acquisitions and divestments. EBITDA for the three months and the trailing twelve months ended September 30, 2015 were $120.9 million and $676.0 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) Upon completion of a material acquisition, the Total Debt to Capitalization maximum ratio may increase to 55% for a period extending to and including the second full fiscal quarter after the completion of the acquisition. Under the renewed credit facility, the maximum ratio increases to 55%.
(2) Senior Debt to EBITDA maximum ratio for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.

Dividends

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per share amounts)	2015	2014	2015	2014
Cash dividends	$ 30.9	$ 51.1	$ 109.2	$ 143.8
Stock dividend plan	–	4.3	–	21.8
Total dividends to shareholders	$ 30.9	$ 55.4	$ 109.2	$ 165.6
Per weighted average share (Basic)	$ 0.15	$ 0.27	$ 0.53	$ 0.81

During the three and nine months ended September 30, 2015 we reported total dividends of $30.9 million ($0.15/share) and $109.2 million ($0.53/share), respectively, compared to $55.4 million ($0.27/share) and $165.6 million ($0.81/share) for the same periods in 2014. For the three and nine months ended September 30, 2015, our cash dividends represented approximately 26% and 28% of funds flow, respectively, compared to 24% and 22% for the same periods in 2014. In September 2014 we elected to suspend our stock dividend plan, thereby eliminating any dilution resulting from issuing shares as part of our dividend plan.

To ensure financial flexibility and balance funds flow with capital and dividends we are reducing our monthly dividend to $0.03 per share from $0.05 per share, effective with the December payment. We expect to save approximately $50 million annually. 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

	Nine months ended September 30, 2015	2014
Share capital ($ millions)	$ 3,132.9	$ 3,115.5
Common shares outstanding (thousands)	206,496	205,423
Weighted average shares outstanding – basic (thousands)	206,100	204,174
Weighted average shares outstanding – diluted (thousands)	206,100	207,970

During the third quarter of 2015 a total of 272,000 shares (2014 – 655,000) and $6.4 million of additional equity (2014 – $12.2 million) was issued pursuant to the stock option plan, the treasury settled LTI plans and the stock dividend plan. For the nine months ended September 30, 2015 a total of 764,000 shares (2014 – 2,665,000) and $12.7 million of additional equity (2014 – $48.9 million) was issued pursuant to the stock option plan, the treasury settled LTI plans and the stock dividend plan. For further details see Note 14.

At September 30, 2015 we had 206,496,000 shares outstanding (2014 – 205,423,000) and at November 5, 2015 we had 206,496,000 shares outstanding.

2015 GUIDANCE

We have increased our annual production guidance, reduced our capital spending guidance and decreased our operating cost and cash G&A expense guidance. All other guidance has been maintained and is summarized below. This guidance includes the fourth quarter sale of a portion of our non-operated North Dakota property but does not include any additional acquisitions or divestments.

Summary of 2015 Expectations	Target
Capital spending	$510 million (from $540 million)
Average annual production	106,000 BOE/day (from 100,000 – 104,000 BOE/day)
Crude oil and natural gas liquids volumes	46,000 bbls/day (from 44,000 – 46,000 bbls/day)
Average royalty and production tax rate (% of gross sales, before transportation)	21%
Operating expenses	$9.00/BOE (from $9.25/BOE)
Transportation costs	$3.00/BOE
Cash G&A expenses	$2.20/BOE (from $2.25/BOE)

2016 GUIDANCE

This guidance includes the fourth quarter sale of a portion of our non-operated North Dakota property but does not include any additional acquisitions or divestments.

Summary of 2016 Expectations	Target
Capital spending	$350 million
Average annual production	100,000 – 105,000 BOE/day
Crude oil and natural gas liquids volumes	44,000 – 47,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	22%
Operating expenses	$9.20/BOE
Transportation costs	$3.00/BOE
Cash G&A expenses	$1.90/BOE

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, 2015, 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, 2015 and ended September 30, 2015 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 2015 and 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 balance sheet and funds flow; our commodity and foreign exchange risk management programs in 2015 and in the future; the results from our drilling program and the timing of related production; oil and natural gas prices, including twelve month trailing prices used in calculation of a ceiling test impairment under U.S. GAAP; 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 2015 and 2016 and its impact on our production level; potential future asset 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 expectations regarding Canadian cash 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; our future acquisitions and dispositions, including timing thereof and expected use of proceeds therefrom; expectations regarding our measures to preserve our financial strength, including effectiveness thereof and amounts of anticipated savings 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, 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 further curtailment of production and/or reduced realized prices; current commodity price 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 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; the availability of third party services; and the extent of our liabilities. In addition, our 2015 guidance contained in this MD&A is based on the following September 30, 2015 forward prices: a WTI price of US$49.68/bbl, a NYMEX price of US$2.75/Mcf, an AECO price of $2.66/GJ and a CDN/USD exchange rate of 1.28. Our 2016 guidance is based on the following price assumptions: a WTI price of US$50/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.85/GJ, a CDN/USD exchange rate of 1.33, a Bakken crude oil differential of US$8.00/bbl below WTI and a Marcellus differential of US$1.25/Mcf below NYMEX.

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 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: changes in, including 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; our risk management programs, including commodity hedging, being less effective in protecting our balance sheet and funds flow than anticipated; 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; changes in estimates of our reserves and resource volumes; limited, unfavorable or a lack of access to capital markets; our inability to comply with covenants under our bank credit facility and senior notes; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; failure to complete any of the anticipated acquisitions or dispositions; 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 our Annual MD&A and in our other public filings).*