enerPLUS

Q3 2017 Third Quarter Report

Nine Months Ended September 30, 2017

SELECTED FINANCIAL RESULTS	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
Financial (000's)				
Net Income/(Loss)	$ 16,131	$ (100,689)	$ 221,726	$ (442,909)
Adjusted Funds Flow[4]	90,386	80,101	324,505	197,875
Dividends to Shareholders	7,264	7,214	21,769	28,225
Debt Outstanding – net of Cash	318,273	654,071	318,273	654,071
Capital Spending	119,102	60,277	341,188	151,673
Property and Land Acquisitions	2,222	3,777	9,471	7,674
Property Divestments	(1,361)	111	57,581	280,614
Net Debt to Adjusted Funds Flow Ratio[4]	0.7x	2.2x	0.7x	2.2x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss)	$ 0.07	$ (0.42)	$ 0.92	$ (2.00)
Weighted Average Number of Shares Outstanding (000's)	242,129	240,483	241,854	221,843
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 33.23	$ 27.20	$ 35.21	$ 23.69
Royalties and Production Taxes	(7.98)	(6.20)	(8.28)	(5.20)
Commodity Derivative Instruments	0.40	1.17	0.51	2.75
Cash Operating Expenses	(6.73)	(6.64)	(6.39)	(7.33)
Transportation Costs	(3.61)	(3.39)	(3.74)	(3.05)
General and Administrative Expenses	(1.61)	(1.58)	(1.67)	(1.79)
Cash Share-Based Compensation	(0.10)	(0.03)	(0.04)	(0.07)
Interest, Foreign Exchange and Other Expenses	(1.17)	(1.07)	(1.25)	(1.37)
Current Income Tax Recovery/(Expense)	(0.01)	(0.01)	(0.10)	0.01
Adjusted Funds Flow[4]	$ 12.42	$ 9.45	$ 14.25	$ 7.64

SELECTED OPERATING RESULTS	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
Average Daily Production[2]				
Crude Oil (bbls/day)	35,245	37,717	35,102	38,764
Natural Gas Liquids (bbls/day)	3,681	4,881	3,659	5,067
Natural Gas (Mcf/day)	241,212	296,876	267,852	304,150
Total (BOE/day)	79,128	92,077	83,403	94,523
% Crude Oil and Natural Gas Liquids	49%	46%	46%	46%
Average Selling Price [2][3]				
Crude Oil (per bbl)	$ 54.21	$ 47.93	$ 55.75	$ 41.92
Natural Gas Liquids (per bbl)	26.22	13.85	29.09	13.53
Natural Gas (per Mcf)	2.58	2.12	3.26	1.79
Net Wells Drilled	10	7	39	24

(1) Non-cash amounts have been excluded.
(2) Based on Company interest production volumes. See "Basis of Presentation" section in the following MD&A.
(3) Before transportation costs, royalties and commodity derivative instruments.
(4) These non-GAAP measures may not be directly comparable to similar measures presented by other entities. See "Non-GAAP Measures" section in the following MD&A.

Average Benchmark Pricing	Three months ended September 30, 2017	2016	Nine months ended September 30, 2017	2016
WTI crude oil (US$/bbl)	$ 48.20	$ 44.94	$ 49.47	$ 41.33
AECO natural gas– monthly index (CDN$/Mcf)	2.04	2.20	2.58	1.85
AECO natural gas – daily index (CDN$/Mcf)	1.45	2.32	2.31	1.85
NYMEX natural gas – last day (US$/Mcf)	3.00	2.81	3.17	2.29
USD/CDN average exchange rate	1.25	1.31	1.31	1.32

Share Trading Summary For the three months ended September 30, 2017	CDN[1] - ERF (CDN$)	U.S.[2] - ERF (US$)
High	$ 12.58	$ 10.21
Low	$ 9.75	$ 7.55
Close	$ 12.31	$ 9.87

(1) TSX and other Canadian trading data combined.
(2) NYSE and other U.S. trading data combined.

2017 Dividends per Share	CDN$	US$[1]
First Quarter Total	$ 0.03	$ 0.02
Second Quarter Total	$ 0.03	$ 0.02
Third Quarter Total	$ 0.03	$ 0.02
Total Year to Date	$ 0.09	$ 0.06

(1) CDN$ dividends converted at the relevant foreign exchange rate on the payment date.

NEWS RELEASE

Highlights:

- On track to deliver full-year 2017 and fourth quarter liquids production targets
- 2017 capital spending guidance unchanged at $450 million
- Produced 33,300 BOE per day (85% oil) in October 2017 from North Dakota, up 60% since the first quarter of 2017
- Ten wells brought on-stream in North Dakota during the third quarter with average peak 30-day production rates per well of 1,890 BOE per day, including the Smooth Green well with a peak 30-day production rate of 3,317 BOE per day
- Realized Bakken differential below WTI averaged US$3.24 per barrel in the third quarter; expecting further improvement to US$2.00 per barrel in the fourth quarter
- Generated adjusted funds flow of $90.4 million

"Our plan for 2017 remains on track and on budget to drive high-return crude oil production and associated cash flow growth from our top tier North Dakota position," stated Ian C. Dundas, President and Chief Executive Officer. "Our strategy of allocating capital to deliver sustainable, profitable cash flow growth continues to enhance our already strong financial position, giving us the flexibility and resiliency to continue to create long-term value for shareholders."

Financial and Operational Summary

Third quarter 2017 production averaged 79,128 BOE per day, including 38,926 barrels per day of crude oil and natural gas liquids. Liquids production for the third quarter was 5% lower than the prior quarter primarily due to the divestment of the Brooks waterflood property which closed in the second quarter, and a completions program in North Dakota weighted to the end of the quarter (approximately 70% of third quarter net completions occurred in September). The Company is on track to drive strong fourth quarter oil volumes with North Dakota production in October averaging 33,300 BOE per day (85% oil), compared to 27,210 BOE per day in the third quarter. Total Company liquids production in October averaged 44,600 barrels per day.

Enerplus remains well positioned relative to its full-year 2017 and fourth quarter liquids production targets. The Company has updated its full-year 2017 liquids production guidance to 40,500 barrels per day (from 39,500 to 41,500 barrels per day) and narrowed its fourth quarter liquids production guidance range to 45,000 to 46,000 barrels per day (from 43,000 to 48,000 barrels per day).

Natural gas production for the third quarter averaged 241 MMcf per day, 11% lower than the prior quarter primarily due to the divestment of Canadian shallow gas properties which closed in the second quarter, and price related production curtailments in the Marcellus during September. Enerplus curtailed approximately 25 MMcf per day of its Marcellus natural gas production during September and approximately 35 MMcf per day in October due to unfavourable prices in the daily cash market. Since early November, regional pricing has improved and the Company has returned to producing at an unrestricted rate of approximately 200 MMcf per day in the Marcellus. Although Enerplus anticipates stronger Marcellus pricing in November and December, the Company remains committed to focusing on value and therefore there may be further curtailment in the event prices weaken during the remainder of the fourth quarter.

As a result of the Marcellus curtailments in September and October, Enerplus has revised its total annual average production guidance for 2017 to 84,000 BOE per day (from 84,000 to 86,000 BOE per day) and its fourth quarter production guidance range to 86,000 to 88,000 BOE per day (from 86,000 to 91,000 BOE per day). This guidance assumes no further Marcellus production curtailments in the fourth quarter. Total Company production in October averaged 82,700 BOE per day.

Enerplus generated adjusted funds flow of $90.4 million in the third quarter, compared to $114.2 million in the previous quarter. The quarter-over-quarter reduction was primarily due to wider natural gas differentials and the strengthening of the Canadian dollar in the third quarter. Tighter Bakken differentials and lower transportation costs in the third quarter partially offset the reduction in adjusted funds flow.

Exploration and development capital spending in the third quarter was $119.1 million associated with drilling, completing, and bringing 10.3 net wells on production. The Company's 2017 exploration and development capital budget of $450 million is unchanged.

Enerplus' realized Bakken crude oil price differential averaged US$3.24 per barrel below WTI in the third quarter, an improvement of US$2.19 per barrel relative to the previous quarter. Spot Bakken prices strengthened considerably throughout the quarter due to the improved egress capacity from the Bakken, on-going Canadian synthetic supply outages, and incremental demand from refineries for light barrels due to on-going market disruption during an active hurricane season. Accordingly, Enerplus is narrowing its expected realized Bakken differential to US$2.00 per barrel below WTI for the fourth quarter and its full-year differential to approximately US$4.00 per barrel below WTI.

Enerplus' realized Marcellus natural gas sales price differential widened to US$1.02 per Mcf below NYMEX in the third quarter compared to US$0.64 per Mcf below NYMEX in the previous quarter. Enerplus' transportation and sales contracts and its fixed basis hedges moderated the weakness as the benchmark monthly Transco Leidy price widened to average US$1.29 per Mcf below NYMEX during the quarter. Marcellus pricing weakened during the quarter due to cooler than average weather in the northeast United States combined with incremental supply coming on-stream during the quarter in expectation of flowing on the subsequently delayed Rover Pipeline. Additional Marcellus pipeline capacity is being brought on-line during the fourth quarter of 2017, including partial capacity of Rover, which is expected to be at full capacity towards the end of the first quarter of 2018. Although pricing strengthened in early November, Marcellus pricing remained weak in October with Transco Leidy daily prices averaging US$0.76 per Mcf. Enerplus is widening its full year 2017 Marcellus realized differential guidance to US$0.80 per Mcf below NYMEX (from US$0.75 per Mcf), and estimates its fourth quarter realized differential will average approximately US$1.05 per Mcf below NYMEX.

Third quarter operating expenses averaged $6.71 per BOE, 15% higher compared to the prior quarter. Operating expenses increased in the third quarter primarily due to lower Marcellus production relative to the previous quarter and higher gas facility charges and well servicing costs on the Company's oil properties. As a result of the impact of the Marcellus curtailment in September and October, Enerplus is increasing its full-year 2017 operating expenses to $6.50 per BOE, from $6.40 per BOE. This increase to operating expense guidance is more than offset by reductions in per BOE transportation and cash G&A guidance, noted below.

Transportation costs in the third quarter averaged $3.61 per BOE, a decrease from $3.72 per BOE in the second quarter of 2017. Transportation costs decreased in the third quarter due to lower Marcellus production relative to the previous quarter and a stronger Canadian dollar. Enerplus is reducing its 2017 guidance for transportation costs to $3.70 per BOE, from $3.90 per BOE.

Cash G&A expenses were $1.61 per BOE for the quarter, compared to $1.53 per BOE in the previous quarter. The modest increase in cash G&A on a BOE basis was due to lower production volumes relative to the previous quarter. Total cash G&A of approximately $11.7 million was broadly flat to the prior quarter. Enerplus is reducing its cash G&A expense guidance to $1.70 per BOE from $1.75 per BOE.

Enerplus remains in a strong financial position. Total debt net of cash at September 30, 2017 was $318.3 million. Total debt was comprised of $667.3 million of senior notes outstanding. The Company was undrawn on its $800 million bank credit facility, and had a cash balance of $349.0 million. At September 30, 2017, Enerplus' net debt to adjusted funds flow ratio was 0.7 times.

Average Daily Production[1]

	Three months ended September 30, 2017			Nine months ended September 30, 2017		
	Oil and NGL (Mbbl/d)	**Natural Gas** (MMcf/d)	**Total** (Mboe/d)	**Oil and NGL** (Mbbl/d)	**Natural Gas** (MMcf/d)	**Total** (Mboe/d)
Williston Basin	28.0	18.7	31.0	26.4	19.0	29.5
Marcellus	—	189.7	31.6	—	199.6	33.3
Canadian Waterfloods[2]	10.1	8.7	11.6	11.4	14.1	13.7
Other[2]	0.8	24.2	4.9	1.1	35.1	6.9
Total	38.9	241.2	79.1	38.8	267.9	83.4

(1) Table may not add due to rounding.
(2) Nine month figures include volumes from Canadian properties that were divested during the first six months of 2017.

Summary of Wells Brought On-Stream[1]

	Three months ended September 30, 2017				Nine months ended September 30, 2017			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	10.0	8.6	1.0	—	29.0	23.4	2.0	0.5
Marcellus	—	—	15.0	0.7	—	—	42.0	3.8
Canadian Waterfloods	—	—	—	—	6.0	6.0	—	—
Other	1.0	1.0	—	—	1.0	1.0	—	—
Total	**11.0**	**9.6**	**16.0**	**0.7**	**36.0**	**30.4**	**44.0**	**4.3**

(1) Table may not add due to rounding.

Asset Activity

WILLISTON BASIN

Williston Basin production averaged 30,981 BOE per day (90% liquids) during the third quarter of 2017, 4% lower than the second quarter. This decrease was expected due to a completions program in North Dakota weighted to the end of the third quarter, in part a function of pad development. Third quarter Williston Basin production was comprised of 27,210 BOE per day in North Dakota and 3,771 BOE per day in Montana.

In the third quarter, Enerplus brought on-stream 10 gross operated wells (86% average working interest) across its acreage at Fort Berthold with an average completed lateral length of 8,770 feet per well and average peak 30-day production rates per well of 1,890 BOE per day (77% oil, on a three-stream basis). Of note are four-wells on the Snakes pad, located in the northwest of Enerplus' Fort Berthold acreage position, a high productivity area. The four wells had an average completed lateral length per well of 9,100 feet and average peak 30-day production rates per well of 2,185 BOE per day (75% oil). The average proppant loading across the 10 operated completions in the quarter was 1,250 pounds per foot, including two wells, Smooth Green (Snakes pad) and Crane (Cranes pad), testing 2,000 pounds per foot. The Smooth Green and Crane wells had peak 30-day production rates of 3,317 BOE per day (75% oil) and 1,950 BOE per day (83% oil) respectively.

The Company drilled 10 gross operated wells (66% average working interest) in the third quarter.

The strong 2017 production growth from North Dakota is set to continue in the fourth quarter with October production from North Dakota averaging 33,300 BOE per day (85% oil).

MARCELLUS

Marcellus production averaged 190 MMcf per day during the third quarter, a reduction of 7% from the previous quarter primarily due to price related curtailments of approximately 25 MMcf per day during September. Fifteen gross non-operated wells (5% average working interest) were brought on-stream during the quarter with an average completed lateral length of 6,300 feet per well and average peak 30-day production rates per well of 14.8 MMcf per day.

The Company participated in drilling 19 gross non-operated wells (12% average working interest) during the third quarter.

Enerplus continued to curtail approximately 35 MMcf per day of its Marcellus production in October due to unfavourable prices in the daily cash market. Since early November, regional pricing has improved and the Company has returned to producing at an unrestricted rate of approximately 200 MMcf per day.

CANADIAN WATERFLOODS

Canadian waterflood production averaged 11,588 BOE per day (87% liquids) during the third quarter, a decrease of 12% from the previous quarter primarily due to the divestment of the Brooks property during the second quarter. Activity in the quarter was largely focused on waterflood optimization and the continued advancement of waterflood implementation at Ante Creek, where total water injection has increased to 9,000 barrels of water per day, with a target injection of approximately 12,000 barrels of water per day by year-end.

2017 Updated Guidance

Enerplus' updated 2017 guidance is summarized below.

	Guidance
Capital spending	$450 million
Average annual production	84,000 BOE/day (from 84,000 - 86,000 BOE/day)
Q4 average production	86,000 – 88,000 BOE/day (from 86,000 - 91,000 BOE/day)
Average annual crude oil and natural gas liquids production	40,500 bbls/day (from 39,500 – 41,500 bbls/day)
Q4 average crude oil and natural gas liquids production	45,000 - 46,000 bbls/day (from 43,000 – 48,000 bbls/day)
Average royalty and production tax rate	24%
Operating expense	$6.50/BOE (from $6.40/BOE)
Transportation expense	$3.70/BOE (from $3.90/BOE)
Cash G&A expense	$1.70/BOE (from $1.75/BOE)

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

(1) Excluding transportation costs.

Risk Management

Enerplus continues to manage price risk through commodity hedging. Using swaps and collar structures, Enerplus has an average of 20,000 barrels per day of crude oil protected for the remainder of 2017 (approximately 72% of forecast crude oil production at the midpoint of annual average guidance, net of royalties), approximately 19,500 barrels per day of crude oil protected in 2018, and 10,000 barrels per day of crude oil protected in 2019.

For natural gas, Enerplus has 50,000 Mcf per day protected for the remainder of 2017 (approximately 25% of forecast natural gas production at the midpoint of annual average guidance, net of royalties) using collar structures. For 2018, Enerplus has 25,000 Mcf per day protected using collar structures.

Commodity Hedging Detail (As at November 8, 2017)

	WTI Crude Oil (US$/bbl)(1)							NYMEX Natural Gas (US$/Mcf)(1)	
	Oct 1, 2017 – Dec 31, 2017	Jan 1, 2018 – Mar 31, 2018	Apr 1, 2018 – Jun 30, 2018	Jul 1, 2018 – Sep 30, 2018	Oct 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Dec 31, 2019	Oct 1, 2017 – Dec 31, 2017	Jan 1, 2018 – Dec 31, 2018
Swaps									
Sold Swaps	$ 53.50	$ 53.73	$ 53.73	$ 53.73	$ 53.73	$ 53.73	—	—	—
Volume (bbls/d or Mcf/d)	2,000	3,000	3,000	3,000	3,000	3,000	—	—	—
Three Way Collars									
Sold Puts	$ 39.62	$ 42.83	$ 42.92	$ 42.71	$ 42.74	$ 43.54	$ 43.48	$ 2.06	—
Volume (bbls/d or Mcf/d)	18,000	13,000	15,000	18,000	20,000	7,000	10,000	50,000	—
Purchased Puts	$ 50.61	$ 53.04	$ 52.90	$ 52.53	$ 52.48	$ 53.21	$ 53.53	$ 2.75	$ 2.75
Volume (bbls/d or Mcf/d)	18,000	13,000	15,000	18,000	20,000	7,000	10,000	50,000	25,000
Sold Calls	$ 60.33	$ 61.99	$ 61.73	$ 61.22	$ 61.10	$ 61.14	$ 62.27	$ 3.41	$ 3.46
Volume (bbls/d or Mcf/d)	18,000	13,000	15,000	18,000	20,000	7,000	10,000	50,000	25,000

(1) Based on weighted average price (before premiums). A portion of the sold puts are settled annually rather than monthly.

Currency and Accounting Principles

All amounts in this news release are stated in Canadian dollars unless otherwise specified. All financial information in this news release has been prepared and presented in accordance with U.S. GAAP, except as noted below under "Non-GAAP Measures".

Barrels of Oil Equivalent

This news release also contains references to "BOE" (barrels of oil equivalent). Enerplus has adopted the standard of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOEs may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.

Presentation of Production Information

Under U.S. GAAP oil and gas sales are generally presented net of royalties and U.S. industry protocol is to present production volumes net of royalties. Under Canadian industry protocol oil and gas sales and production volumes are presented on a gross basis before deduction of royalties. In order to continue to be comparable with its Canadian peer companies, the summary results contained within this news release presents Enerplus' production and BOE measures on a before royalty company interest basis. All production volumes and revenues presented herein are reported on a "company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest.

Readers are cautioned that the average initial production rates contained in this news release are not necessarily indicative of long-term performance or of ultimate recovery.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "should", "believe", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this news release contains forward-looking information pertaining to the following: expected average production volumes in 2017 and the anticipated production mix; the portion of Marcellus production that is curtailed; the proportion of anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting funds flow; the results from the drilling program and the timing of related production; oil and natural gas prices and differentials and commodity risk management programs in 2017, 2018, and beyond; expectations regarding realized oil and natural gas prices; future royalty rates on 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 2017 and its impact on production levels and land holdings; future royalty and production and cash taxes; future debt and working capital levels and debt to funds flow ratios.

The forward-looking information contained in this news release reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that Enerplus will conduct its operations and achieve results of operations as anticipated; that Enerplus' development plans will achieve the expected results; 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 Enerplus' reserves and resources volumes; the continued availability of adequate debt and/or equity financing, cash flow and other sources to fund Enerplus' capital and operating requirements, and dividend payments, as needed; availability of third party services; and the extent of its liabilities. In addition, our updated 2017 guidance contained in this news release is based on the following prices for the rest of the year: a WTI price of US$50.00/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.00/GJ and a USD/CDN exchange rate of 1.28. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this news release 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: changes, including continued volatility, in commodity prices; changes in realized prices for Enerplus' products; changes in the demand for or supply of Enerplus' products; unanticipated operating results, results from Enerplus' capital spending activities or production declines; curtailment of Enerplus' 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 development plans by Enerplus or by third party operators of Enerplus' properties; increased debt levels or debt service requirements; Enerplus' inability to comply with covenants under its bank credit facility and senior notes; changes in estimates of Enerplus' oil and gas reserves and resources 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; failure to complete any anticipated acquisitions or divestitures; and certain other risks detailed from time to time in Enerplus' public disclosure documents (including, without limitation, those risks identified in its Annual Information Form, management's discussion and analysis for the year-ended December 31, 2016, and Form 40-F at December 31, 2016).

The forward-looking information contained in this press release speak only as of the date of this press release. Enerplus does not undertake any obligation to publicly update or revise any forward-looking information contained herein, except as required by applicable laws.

NON-GAAP MEASURES

In this news release, we use the terms "adjusted funds flow" and "net debt to adjusted funds flow ratio" as measures to analyze operating performance, leverage and liquidity. "Adjusted funds flow" is calculated as net cash generated from operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures. "Net debt to adjusted funds flow ratio" is calculated as total debt net of cash and restricted cash, divided by a trailing 12 months of adjusted funds flow. Calculation of these terms is described in Enerplus' MD&A under the "Liquidity and Capital Resources" section.

Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "adjusted funds flow" and "net debt to adjusted funds flow" are useful supplemental measures as they provide an indication of the results generated by Enerplus' principal business activities. However, these measures are not measures recognized by U.S. GAAP and do not have a standardized meaning prescribed by U.S. GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers. For reconciliation of these measures to the most directly comparable measure calculated in accordance with U.S. GAAP, and further information about these measures, see disclosure under "Non-GAAP Measures" in Enerplus' Third Quarter 2017 MD&A.

Electronic copies of Enerplus Corporation's Third Quarter 2017 MD&A and Financial Statements, along with other public information including investor presentations, are available on its website at www.enerplus.com. Shareholders may, upon request, receive a printed copy of the Company's audited financial statements at any time. For further information, please contact Investor Relations at 1-800-319-6462 or email investorrelations@enerplus.com.

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

The following discussion and analysis of financial results is dated November 8, 2017 and is to be read in conjunction with:

- the unaudited interim condensed consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three and nine months ended September 30, 2017 and 2016 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014; and
- our MD&A for the year ended December 31, 2016 (the "Annual MD&A").

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" at the end of the MD&A for further information.

BASIS OF PRESENTATION

The Interim Financial Statements and notes have been prepared in accordance with U.S. GAAP, including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included in the Interim Financial Statements. Certain prior period amounts have been restated to conform with current period presentation.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 bbl and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcf. BOE and Mcfe measures are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. All production volumes are presented on a Company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests unless otherwise stated. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and may not be comparable to information produced by other entities.

In accordance with U.S. GAAP, oil and gas sales are presented net of royalties in our Interim Financial Statements. Under International Financial Reporting Standards, industry standard is to present oil and gas sales before deduction of royalties and as such this MD&A presents production, oil and gas sales, and BOE measures on this basis to remain comparable with our peers.

OVERVIEW

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

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

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

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

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

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

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

RESULTS OF OPERATIONS

Production

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

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

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

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

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

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, adjusted funds flow and financial condition. The following table compares average prices for the nine months ended September 30, 2017 and 2016 and quarterly average prices for the periods indicated:

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

(1) Excluding transportation costs, royalties and commodity derivative instruments.
(2) Based on a weighted average differential for the period.

CRUDE OIL AND NATURAL GAS LIQUIDS

Our average realized crude oil price decreased by 3% during the quarter to average $54.21/bbl. The strengthening of the Canadian dollar largely offset the improvement in realized crude oil differentials from the second quarter, with WTI prices essentially unchanged.

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

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

NATURAL GAS

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

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

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

FOREIGN EXCHANGE

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

Price Risk Management

We have a price risk management program that considers our overall financial position and the economics of our capital expenditures.

As of November 8, 2017, we have hedged 20,000 bbls/day of our expected crude oil production for the remainder of 2017, which represents approximately 72% of our 2017 forecasted crude oil production, after royalties. For 2018, we have hedged approximately 19,500 bbls/day, which represents approximately 70% of our 2017 forecasted crude oil production, after royalties. For 2019, we have hedged 10,000 bbls/day, which represents approximately 36% of our 2017 forecasted crude oil production, after royalties. Our crude oil hedges are predominantly three way collars, which consist of a sold put, a purchased put and a sold call. When WTI prices settle below the sold put strike price, the three way collars provide a limited amount of protection above the WTI settled price equal to the difference between the strike price of the purchased and sold puts. Overall, we expect our crude oil related hedging contracts to protect a significant portion of our funds flow.

As of November 8, 2017, we have hedged 50,000 Mcf/day of our forecasted natural gas production for the remainder of 2017. This represents approximately 25% of our forecasted natural gas production, after royalties. For 2018 we have hedged 25,000 Mcf/day, which represents 13% of our 2017 forecasted natural gas production, after royalties.

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

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

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

ACCOUNTING FOR PRICE RISK MANAGEMENT

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

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

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

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At the end of the third quarter of 2017, the fair value of our crude oil contracts was in a net asset position of $5.3 million, while the fair value of our natural gas contracts was in a net liability position of $0.1 million. For the three and nine months ended September 30, 2017, the change in the fair value of our crude oil contracts represented losses of $37.4 million and gains of $34.2 million, respectively, and our natural gas contracts represented gains of $0.3 million and $9.4 million, respectively.

Revenues

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

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

Royalties and Production Taxes

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

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

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

Operating Expenses

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

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

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

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

Transportation Costs

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

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

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

Netbacks

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

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

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

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

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

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

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

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

General and Administrative ("G&A") Expenses

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

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2017	2016	2017	2016
Cash:				
G&A expense	$ 11.7	$ 13.4	$ 37.9	$ 46.4
Share-based compensation expense	0.7	0.2	0.9	1.8
Non-Cash:				
Share-based compensation expense	4.1	2.9	15.6	11.7
Equity swap loss/(gain)	(0.8)	0.1	0.2	(1.6)
Total G&A expenses	$ 15.7	$ 16.6	$ 54.6	$ 58.3

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

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

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

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

Interest Expense

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

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

Foreign Exchange

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

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

Capital Investment

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

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

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

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

Gain on Asset Sales and Note Repurchases

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

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

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

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

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

Impairment

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

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

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

Asset Retirement Obligation

In connection with our operations, we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are based on our net ownership interest and management's estimate of costs to abandon and reclaim such assets and the timing of the cost to be incurred in future periods. We have estimated the net present value of our asset retirement obligation to be $105.5 million at September 30, 2017, compared to $181.7 million at December 31, 2016. For the three and nine months ended September 30, 2017, asset retirement obligation settlements were $3.1 million and $7.1 million, respectively, compared to $1.2 million and $4.4 million during the same periods in 2016. As a result of our divestments to date in 2017, we have reduced our asset retirement obligation by $72.1 million or 40%. See Note 9 to the Interim Financial Statements for further details.

Income Taxes

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage, including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging and dividend levels. We also assess our leverage relative to our most restrictive debt covenant under our bank credit facility and senior notes, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At September 30, 2017, our senior debt to adjusted EBITDA ratio was 0.8x and our net debt to adjusted funds flow ratio was 0.7x. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate our liquidity.

Total debt net of cash at September 30, 2017 was $318.3 million, a decrease of 15% compared to $375.5 million at December 31, 2016. Total debt was comprised of $667.3 million of senior notes less $349.0 million in cash. At September 30, 2017, we were fully undrawn on our $800 million bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by adjusted funds flow, was 140% and 112% for the three and nine months ended September 30, 2017, respectively, compared to 85% and 91% for the same periods in 2016. After adjusting for net divestments of $48.1 million, we had a funding surplus of $8.6 million for the nine months ended September 30, 2017.

Our working capital deficiency, excluding cash, restricted cash and current deferred financial assets and liabilities, increased to $122.9 million at September 30, 2017 from $94.4 million at December 31, 2016. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, adjusted funds flow and our bank credit facility. We have sufficient liquidity to meet our financial commitments, as disclosed under "Commitments" in the Annual MD&A.

Subsequent to the quarter, we completed a one year extension of our $800 million senior, unsecured, covenant-based bank credit facility, which now matures on October 31, 2020. There were no other amendments to the agreement terms or covenants. Drawn fees on the facility range between 150 and 315 basis points over Banker's Acceptance rates, with current drawn fees of 150 basis points over Banker's Acceptance rates based on our last reported senior debt to adjusted EBITDA ratio. The bank credit facility ranks equally with our senior, unsecured covenant-based notes.

At September 30, 2017, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com.

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

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

Definitions

"Senior debt" is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.

"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended September 30, 2017 was $85.6 million and $857.4 million, respectively.

"Total debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.

"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes

(1) See "Non-GAAP Measures" in this MD&A for a reconciliation of adjusted EBITDA to net income.
(2) Senior debt to adjusted EBITDA may increase to 3.5x for a period of 6 months for the senior notes, after which the ratio decreases to 3.0x.
(3) Senior debt to consolidated present value of total proved reserves is calculated annually on December 31 based on before tax reserves at forecast prices discounted at 10%.

Dividends

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

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

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

Shareholders' Capital

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

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

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

At November 8, 2017, we had 242,128,944 common shares outstanding. In addition, an aggregate of 13,033,023 common shares may be issued to settle outstanding grants under the Performance Share Unit ("PSU"), Restricted Share Unit, and stock option plans, assuming the maximum payout multiplier of 2.0 times for the PSUs.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

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

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

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

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2017				
Third Quarter	$ 196.1	$ 16.1	$ 0.07	$ 0.07
Second Quarter	225.7	129.3	0.53	0.52
First Quarter	227.8	76.3	0.32	0.31
Total 2017	$ 649.6	$ 221.7	$ 0.92	$ 0.90
2016				
Fourth Quarter	$ 217.4	$ 840.3	$ 3.49	$ 3.43
Third Quarter	188.3	(100.7)	(0.42)	(0.42)
Second Quarter	174.3	(168.5)	(0.77)	(0.77)
First Quarter	142.7	(173.7)	(0.84)	(0.84)
Total 2016	$ 722.7	$ 397.4	$ 1.75	$ 1.72
2015				
Fourth Quarter	$ 199.4	$ (625.0)	$ (3.03)	$ (3.03)
Third Quarter	228.3	(292.7)	(1.42)	(1.42)
Second Quarter	251.7	(312.5)	(1.52)	(1.52)
First Quarter	205.0	(293.2)	(1.42)	(1.42)
Total 2015	$ 884.4	$ (1,523.4)	$ (7.39)	$ (7.39)

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

2017 UPDATED GUIDANCE

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

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

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

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

(1) Excluding transportation costs.

NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and therefore may not be comparable with the calculation of similar measures by other entities:

"Netback" is used by Enerplus and is useful to investors and securities analysts in evaluating operating performance of our crude oil and natural gas assets. Netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating expenses and transportation costs.

Calculation of Netback	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2017	2016	2017	2016
Oil and natural gas sales	$ 241.9	$ 230.4	$ 801.7	$ 613.6
Less:				
Royalties	(45.8)	(42.1)	(152.1)	(108.3)
Production taxes	(12.3)	(10.4)	(36.5)	(26.4)
Cash operating expenses[1]	(48.9)	(56.2)	(145.4)	(189.9)
Transportation costs	(26.3)	(28.8)	(85.1)	(78.9)
Netback before hedging	$ 108.6	$ 92.9	$ 382.6	$ 210.1
Cash gains/(losses) on derivative instruments	2.9	10.0	11.7	71.1
Netback after hedging	$ 111.5	$ 102.9	$ 394.3	$ 281.2

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

"Adjusted funds flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. Adjusted funds flow is calculated as net cash from operating activities before asset retirement obligation expenditures and changes in non-cash operating working capital.

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

"Total debt net of cash" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. Total debt net of cash is calculated as senior notes plus any outstanding bank credit facility balance, minus cash and restricted cash.

"**Net debt to adjusted funds flow ratio**" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The net debt to adjusted funds flow ratio is calculated as total debt net of cash divided by a trailing twelve months of adjusted funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") and is not a debt covenant.

"**Adjusted payout ratio**" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. We calculate our adjusted payout ratio as cash dividends plus capital and office expenditures divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	Three months ended September 30,				Nine months ended September 30,			
($ millions)		2017		2016		2017		2016
Dividends	$	7.3	$	7.2	$	21.8	$	28.2
Capital and office expenditures		119.6		60.9		342.2		152.4
Sub-total	$	126.9	$	68.1	$	364.0	$	180.6
Adjusted funds flow	$	90.4	$	80.1	$	324.5	$	197.9
Adjusted payout ratio (%)		140%		85%		112%		91%

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

Reconciliation of Net Income to Adjusted EBITDA(1)

($ millions)		September 30, 2017
Net income/(loss)	$	1,062.1
Add:		
Interest		39.2
Current and deferred tax expense/(recovery)		(508.3)
DD&A and asset impairment		294.4
Other non-cash charges(2)		(10.5)
Sub-total	$	876.9
Adjustment for material acquisitions and divestments(3)		(19.5)
Adjusted EBITDA	$	857.4

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

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "senior debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "maximum debt to consolidated present value of total proved reserves" and "adjusted EBITDA to interest" and are used to determine the Company's compliance with financial covenants under its bank credit facility and outstanding senior notes. Calculation of such terms is described under the "Liquidity and Capital Resources" section of this MD&A.

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a - 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at September 30, 2017, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on July 1, 2017 and ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current Annual Information Form ("AIF"), is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected 2017 total, fourth quarter 2017 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our adjusted funds flow; anticipated production volumes subject to curtailment; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management program in 2017 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated *cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2017 and impact thereof on our production levels and land holdings; potential future asset and goodwill impairments, as well as relevant factors that may affect such impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes and to negotiate relief if required; our future acquisitions and dispositions, expecting timing thereof and use of proceeds therefrom; and the amount of future cash dividends that we may pay to our shareholders.*

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to negotiate debt covenant relief under our bank credit facility and outstanding senior notes if required; the availability of third party services; and the extent of our liabilities. In addition, our updated 2017 guidance contained in this MD&A is based on the following prices for the fourth quarter: a WTI price of US$50.00/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.00/GJ and a USD/CDN exchange rate of 1.28. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued low commodity prices environment or further volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our AIF, our Annual MD&A and Form 40-F as at December 31, 2016).

The forward-looking information contained in this MD&A speak only as of the date of this MD&A. Enerplus does not undertake any obligation to publicly update or revise any forward-looking information contained herein, except as required by applicable laws.

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	September 30, 2017	December 31, 2016
Assets			
Current Assets			
Cash		$ 349,047	$ 1,257
Restricted cash		—	392,048
Accounts receivable	4	86,225	115,368
Deferred financial assets	15	9,956	—
Other current assets		11,952	6,721
		457,180	515,394
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	5	810,102	726,452
Other capital assets, net	5	9,437	11,978
Property, plant and equipment		819,539	738,430
Goodwill		637,399	651,663
Deferred financial assets	15	1,562	—
Deferred income tax asset	13	636,717	733,363
Total Assets		$ 2,552,397	$ 2,638,850
Liabilities			
Current liabilities			
Accounts payable	7	$ 191,188	$ 184,534
Dividends payable		2,421	2,405
Current portion of long-term debt	8	27,438	29,539
Deferred financial liabilities	15	3,271	28,615
		224,318	245,093
Deferred financial liabilities	15	5,331	12,266
Long-term debt	8	639,882	739,286
Asset retirement obligation	9	105,478	181,700
		750,691	933,252
Total Liabilities		975,009	1,178,345
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: September 30, 2017 – 242 million shares			
December 31, 2016 – 240 million shares	14	3,386,946	3,365,962
Paid-in capital		68,400	73,783
Accumulated deficit		(2,132,684)	(2,332,641)
Accumulated other comprehensive income		254,726	353,401
		1,577,388	1,460,505
Total Liabilities & Shareholders' Equity		$ 2,552,397	$ 2,638,850

Contingencies	16
Subsequent event	8

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Condensed Consolidated Statements of Income/(Loss) and Comprehensive Income/(Loss)

(CDN$ thousands, except per share amounts) unaudited	Note	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
Revenues					
Oil and natural gas sales, net of royalties	10	$ 196,068	$ 188,318	$ 649,579	$ 505,309
Commodity derivative instruments gain/(loss)	15	(34,215)	12,072	55,295	3,629
		161,853	200,390	704,874	508,938
Expenses					
Operating		48,843	56,238	144,992	189,368
Transportation		26,314	28,755	85,147	78,968
Production taxes		12,330	10,408	36,497	26,385
General and administrative	11	15,741	16,612	54,574	58,309
Depletion, depreciation and accretion		59,758	91,766	185,117	266,001
Asset impairment	6	—	60,956	—	255,812
Interest		8,663	9,685	29,015	34,283
Foreign exchange (gain)/loss	12	(17,577)	3,085	(33,585)	(50,940)
Gain on divestment of assets	5	—	—	(78,400)	(219,800)
Gain on prepayment of senior notes	8	—	—	—	(19,270)
Other expense/(income)		(743)	247	(1,786)	5
		153,329	277,752	421,571	619,121
Income/(Loss) before taxes		8,524	(77,362)	283,303	(110,183)
Current income tax expense/(recovery)	13	84	126	2,198	(260)
Deferred income tax expense/(recovery)	13	(7,691)	23,201	59,379	332,986
Net Income/(Loss)		$ 16,131	$ (100,689)	$ 221,726	$ (442,909)
Other Comprehensive Income/(Loss)					
Change in cumulative translation adjustment		(52,019)	4,480	(98,675)	(60,234)
Other Comprehensive Income/(Loss)		(52,019)	4,480	(98,675)	(60,234)
Total Comprehensive Income/(Loss)		$ (35,888)	$ (96,209)	$ 123,051	$ (503,143)
Net income/(Loss) per share					
Basic	14	$ 0.07	$ (0.42)	$ 0.92	$ (2.00)
Diluted	14	$ 0.07	$ (0.42)	$ 0.90	$ (2.00)

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Condensed Consolidated Statements of Changes in Shareholders' Equity

(CDN$ thousands) unaudited	Nine months ended September 30, 2017	2016
Share Capital		
Balance, beginning of year	$ 3,365,962	$ 3,133,524
Issue of shares (net of issue costs)	—	223,031
Share-based compensation – settled	20,984	9,407
Balance, end of period	$ 3,386,946	$ 3,365,962
Paid-in Capital		
Balance, beginning of year	$ 73,783	$ 56,176
Share-based compensation – settled	(20,984)	(9,407)
Share-based compensation – non-cash	15,601	11,751
Balance, end of period	$ 68,400	$ 58,520
Accumulated Deficit		
Balance, beginning of year	$ (2,332,641)	$ (2,694,618)
Net income/(loss)	221,726	(442,909)
Dividends	(21,769)	(28,225)
Balance, end of period	$ (2,132,684)	$ (3,165,752)
Accumulated Other Comprehensive Income/(Loss)		
Balance, beginning of year	$ 353,401	$ 402,672
Change in cumulative translation adjustment	(98,675)	(60,234)
Balance, end of period	$ 254,726	$ 342,438
Total Shareholders' Equity	$ 1,577,388	$ 601,168

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Note	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
Operating Activities					
Net income/(loss)		$ 16,131	$ (100,689)	$ 221,726	$ (442,909)
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		59,758	91,766	185,117	266,001
Asset impairment		—	60,956	—	255,812
Changes in fair value of derivative instruments	15	36,163	(2,024)	(43,797)	65,371
Deferred income tax expense/(recovery)	13	(7,691)	23,201	59,379	332,986
Foreign exchange (gain)/loss on debt and working capital	12	(31,639)	3,960	(48,614)	(52,067)
Share-based compensation	14	4,171	2,931	15,601	11,751
Foreign exchange loss on translation of U.S. dollar cash held in Canada	12	13,493	—	13,493	—
Gain on divestment of assets	5	—	—	(78,400)	(219,800)
Gain on prepayment of senior notes	8	—	—	—	(19,270)
Asset retirement obligation expenditures	9	(3,060)	(1,237)	(7,124)	(4,441)
Changes in non-cash operating working capital	17	27,250	27,077	23,412	44,141
Cash flow from operating activities		114,576	105,941	340,793	237,575
Financing Activities					
Cash dividends		(7,264)	(7,214)	(21,769)	(28,225)
Decrease in bank credit facility		—	—	(23,272)	(79,223)
Repayment of senior notes	8	—	—	(29,084)	(335,400)
Proceeds from the issuance of shares		—	—	—	220,410
Changes in non-cash financing working capital		—	—	16	(3,791)
Cash flow used in financing activities		(7,264)	(7,214)	(74,109)	(226,229)
Investing Activities					
Capital and office expenditures		(119,649)	(60,856)	(342,164)	(152,354)
Property and land acquisitions		(2,222)	(3,777)	(9,471)	(7,674)
Property divestments	5	(1,361)	111	57,581	280,614
Decrease in restricted cash		—	—	380,939	—
Changes in non-cash investing working capital		(6,577)	(9,055)	9,674	(63,090)
Cash flow from/(used in) investing activities		(129,809)	(73,577)	96,559	57,496
Effect of exchange rate changes on cash		(13,514)	683	(15,453)	(1,335)
Change in cash		(36,011)	25,833	347,790	67,507
Cash, beginning of period		385,058	49,172	1,257	7,498
Cash, end of period		$ 349,047	$ 75,005	$ 349,047	$ 75,005

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Notes to Condensed Consolidated Financial Statements
(unaudited)

1) REPORTING ENTITY

These interim Condensed Consolidated Financial Statements ("interim Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation ("The Company" or "Enerplus") including its Canadian and U.S. subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada. The interim Consolidated Financial Statements were authorized for issue by the Board of Directors on November 8, 2017.

2) BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under accounting principles generally accepted in the United States of America ("U.S. GAAP") for the three and nine months ended September 30, 2017 and the 2016 comparative periods. Certain information and notes normally included with the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Condensed Consolidated Financial Statements should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2016. There are no differences in the use of estimates or judgments between these interim Condensed Consolidated Financial Statements and the audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2016.

These unaudited interim Consolidated Financial Statements reflect, in the opinion of Management, all normal and recurring adjustments necessary to present fairly the financial position and results of the Company as at and for the periods presented.

3) FUTURE ACCOUNTING POLICY CHANGES

In future accounting periods, the Company will adopt the following Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"):

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606),* which requires entities to recognize revenue on the transfer of promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The new standard also will require expanded disclosures regarding the nature, amount, timing and certainty of revenue and cash flows from contracts with customers. The FASB further issued several ASUs in 2016 which provide clarification on implementation of the amended standard, technical corrections, improvements and practical expedients that can be applied under certain circumstances. The guidance in Topic 606, as amended, will be effective for annual periods beginning on or after December 15, 2017, and will be adopted by Enerplus on January 1, 2018 using the modified retrospective method. Enerplus continues to review its sales contracts with customers but does not expect any material impact to the Consolidated Financial Statements other than enhanced disclosures. The Company is currently addressing any process changes necessary to compile the information to meet the additional note disclosure requirements of the new standard.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842).* The ASU introduced a lessee accounting model that requires lessees to recognize a right-of-use asset and related lease liability on the balance sheet for all leases, including operating leases. The standard does not apply to oil and gas exploration rights, intangible assets or inventory. The new standard also expands disclosures related to the amount, timing and uncertainty of cash flows arising from leases. The standard will be applied using a modified retrospective approach and provides for certain practical expedients at the date of adoption. The ASU is effective January 1, 2019. Enerplus does not expect to early adopt the standard. The Company is currently reviewing existing contracts to determine the impact to the Consolidated Financial Statements of adopting the new standard. The Company is also addressing system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new standard.

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments – Credit Losses (Topic 326)*. The ASU significantly changes how entities measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than a direct write down of the amortized cost basis. The new guidance is effective January 1, 2020, and will be applied using a modified retrospective approach. Enerplus does not expect to early adopt the standard and continues to assess the impact it will have on the Consolidated Financial Statements.

In January 2017, the FASB issued ASU 2017-04, *Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment (Topic 350)*. This standard eliminates Step 2 of the goodwill impairment test, and requires a goodwill impairment charge for the amount that the carrying amount of the reporting unit exceeds the reporting unit's fair value. The updated guidance is effective January 1, 2020, and will be applied prospectively. Enerplus does not expect to early adopt the standard. The amended standard may affect goodwill impairment tests past the adoption date, the impact of which is not known.

4) ACCOUNTS RECEIVABLE

($ thousands)	September 30, 2017	December 31, 2016
Accrued receivables	$ 66,478	$ 83,774
Accounts receivable – trade	21,108	33,305
Current income tax receivable	1,796	1,564
Allowance for doubtful accounts	(3,157)	(3,275)
Total accounts receivable, net of allowance for doubtful accounts	$ 86,225	$ 115,368

5) PROPERTY, PLANT AND EQUIPMENT ("PP&E")

As of September 30, 2017 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 13,439,631	$ (12,629,529)	$ 810,102
Other capital assets	105,766	(96,329)	9,437
Total PP&E	$ 13,545,397	$ (12,725,858)	$ 819,539

As of December 31, 2016 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 13,567,390	$ (12,840,938)	$ 726,452
Other capital assets	106,070	(94,092)	11,978
Total PP&E	$ 13,673,460	$ (12,935,030)	$ 738,430

Under full cost accounting rules, divestitures of oil and gas properties are generally accounted for as adjustments to capitalized costs, with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would have otherwise significantly altered the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized.

For the nine months ended September 30, 2017, Enerplus recorded a gain on asset divestments of $78.4 million on the sale of certain Canadian assets for proceeds of $59.3 million, after closing adjustments (nine months ended September 30, 2016 – gains of $219.8 million, and proceeds of $280.6 million after closing adjustments).

6) ASSET IMPAIRMENT

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2017	2016	2017	2016
Oil and natural gas properties:				
Canada cost centre	$ —	$ 9,800	$ —	$ 44,000
U.S. cost centre	—	51,156	—	211,812
Impairment expense	$ —	$ 60,956	$ —	$ 255,812

There was no impairment recorded for the nine months ended September 30, 2017. The impairment for the three and nine months ended September 30, 2016 was due to lower 12-month average trailing crude oil and natural gas prices.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from September 30, 2016 through September 30, 2017:

Period	WTI Crude Oil US$/bbl	Exchange Rate US$/CDN$	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	AECO Natural Gas Spot CDN$/Mcf
Q3 2017	$ 49.81	1.32	$ 61.63	$ 3.05	$ 2.66
Q2 2017	48.95	1.33	60.79	3.05	2.79
Q1 2017	47.61	1.31	58.02	2.77	2.41
Q4 2016	42.75	1.32	52.26	2.49	2.17
Q3 2016	41.68	1.32	51.17	2.27	2.06

7) ACCOUNTS PAYABLE

($ thousands)	September 30, 2017	December 31, 2016
Accrued payables	$ 104,979	$ 104,816
Accounts payable - trade	86,209	79,718
Total accounts payable	$ 191,188	$ 184,534

8) DEBT

($ thousands)	September 30, 2017	December 31, 2016
Current:		
Senior notes	$ 27,438	$ 29,539
	27,438	29,539
Long-term:		
Bank credit facility	$ —	$ 23,226
Senior notes	639,882	716,060
	639,882	739,286
Total debt	$ 667,320	$ 768,825

The terms and rates of the Company's outstanding senior notes are provided below:

Issue Date	Interest Payment Dates	Principal Repayment	Coupon Rate	Original Principal ($ thousands)	Remaining Principal ($ thousands)	CDN$ Carrying Value ($ thousands)
September 3, 2014	March 3 and Sept 3	5 equal annual installments beginning September 3, 2022	3.79%	US$200,000	US$105,000	$ 130,956
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2019	4.34%	CDN$30,000	CDN$30,000	30,000
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	24,944
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	371,666
June 18, 2009	June 18 and Dec 18	4 equal annual installments June 18, 2018 - 2021	7.97%	US$225,000	US$88,000	109,754
					Total carrying value	$ 667,320

During the nine months ended September 30, 2017, Enerplus made a principal repayment of US$22 million on its 2009 senior notes. There were no principal repayments during the three months ended September 30, 2017. For the nine months ended September 30, 2016, Enerplus repurchased US$267 million in outstanding senior notes at a discount, resulting in gains of $19.3 million.

Subsequent to the quarter, Enerplus extended its $800 million senior, unsecured bank credit facility to October 31, 2020. There were no other amendments to the agreement terms or covenants.

9) ASSET RETIREMENT OBLIGATION

($ thousands)	Nine months ended September 30, 2017	Year ended December 31, 2016
Balance, beginning of year	$ 181,700	$ 206,359
Change in estimates	(3,221)	5,496
Property acquisitions and development activity	827	3,003
Dispositions	(72,096)	(35,635)
Settlements	(7,124)	(8,390)
Accretion expense	5,392	10,867
Balance, end of period	$ 105,478	$ 181,700

Enerplus has estimated the present value of its asset retirement obligation to be $105.5 million at September 30, 2017 based on a total undiscounted liability of $308.0 million (December 31, 2016 – $181.7 million and $452.1 million, respectively). The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.81% (December 31, 2016 – 5.86%).

10) OIL AND NATURAL GAS SALES

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2017	2016	2017	2016
Oil and natural gas sales	$ 241,883	$ 230,421	$ 801,718	$ 613,585
Royalties[1]	(45,815)	(42,103)	(152,139)	(108,276)
Oil and natural gas sales, net of royalties	$ 196,068	$ 188,318	$ 649,579	$ 505,309

(1) Royalties above do not include production taxes which are reported separately on the Condensed Consolidated Statements of Income/(Loss).

11) GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2017	2016	2017	2016
General and administrative expense	$ 11,685	$ 13,390	$ 37,937	$ 46,386
Share-based compensation expense[1]	4,056	3,222	16,637	11,923
General and administrative expense	$ 15,741	$ 16,612	$ 54,574	$ 58,309

(1) Includes cash and non-cash share-based compensation.

12) FOREIGN EXCHANGE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2017	2016	2017	2016
Realized:				
Foreign exchange (gain)/loss on settlements	$ 569	$ (875)	$ 1,536	$ 1,127
Translation of U.S. dollar cash held in Canada	13,493	—	13,493	—
Unrealized:				
Translation of U.S. dollar debt and working capital (gain)/loss	(31,639)	3,960	(48,614)	(52,067)
Foreign exchange (gain)/loss	$ (17,577)	$ 3,085	$ (33,585)	$ (50,940)

13) INCOME TAXES

($ thousands)	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
Current tax expense/(recovery)				
Canada	$ (400)	$ —	$ (400)	$ (669)
United States	484	126	2,598	409
Current tax expense/(recovery)	84	126	2,198	(260)
Deferred tax expense/(recovery)				
Canada	$ (15,241)	$ 28,118	$ 23,941	$ 62,033
United States	7,550	(4,917)	35,438	270,953
Deferred tax expense/(recovery)	(7,691)	23,201	59,379	332,986
Income tax expense/(recovery)	$ (7,607)	$ 23,327	$ 61,577	$ 332,726

The difference between the expected and effective income taxes for the current and prior period is impacted by expected annual earnings, changes in valuation allowance, foreign, statutory and other rate differentials, non-taxable capital gains and losses, and non-deductible share-based compensation. At September 30, 2017 Enerplus' total valuation allowance was $341.2 million (December 31, 2016 - $347.9 million).

14) SHAREHOLDERS' EQUITY

a) Share Capital

	Nine months ended September 30, 2017		Year ended December 31, 2016	
Authorized unlimited number of common shares issued: (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	240,483	$ 3,365,962	206,539	$ 3,133,524
Issued for cash:				
Issue of shares	—	—	33,350	230,115
Share issue costs (net of tax of $2,621)	—	—	—	(7,084)
Non-cash:				
Share-based compensation – settled	1,646	20,984	594	9,407
Balance, end of period	242,129	$ 3,386,946	240,483	$ 3,365,962

Dividends declared to shareholders for the three and nine months ended September 30, 2017 were $7.3 million and $21.8 million, respectively (2016 - $7.2 million and $28.2 million, respectively).

On May 31, 2016, Enerplus issued 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230,115,000 ($220,410,400, net of issue costs before tax).

b) Share-based Compensation

The following table summarizes Enerplus' share-based compensation expense, which is included in General and Administrative expense on the Consolidated Statements of Income/(Loss):

($ thousands)	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
Cash:				
Long-term incentive plans expense	$ 712	$ 233	$ 852	$ 1,769
Non-cash:				
Long-term incentive plans	4,171	2,931	15,601	11,751
Equity swap (gain)/loss	(827)	58	184	(1,597)
Share-based compensation expense	$ 4,056	$ 3,222	$ 16,637	$ 11,923

i) Long-term Incentive ("LTI") Plans

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Director Share Unit ("DSU") plan activity for the nine months ended September 30, 2017:

For the nine months ended September 30, 2017	**Cash-settled LTI plans**	**Equity-settled LTI plans**		**Total**
(thousands of units)	**DSU**	**PSU**	**RSU**	
Balance, beginning of year	306	2,442	2,698	5,446
Granted	61	829	820	1,710
Vested	—	(528)	(1,118)	(1,646)
Forfeited	—	(36)	(264)	(300)
Balance, end of period	367	2,707	2,136	5,210

Cash-settled LTI Plans

For the three and nine months ended September 30, 2017, the Company recorded cash share-based compensation expense of $0.7 and $0.9 million, respectively (September 30, 2016 – $0.2 million and $1.8 million, respectively). For the three and nine months ended September 30, 2017 the Company made cash payments of nil and $0.1 million, respectively, related to its cash-settled plans (September 30, 2016 – nil and $2.7 million, respectively).

As of September 30, 2017, a liability of $4.5 million (December 31, 2016 - $3.9 million) with respect to the DSU plan has been recorded to Accounts Payable on the Consolidated Balance Sheets.

Equity-settled LTI Plans

For the three and nine months ended September 30, 2017 the Company recorded non-cash share-based compensation expense of $4.2 million and $15.6 million, respectively (2016 – $2.9 million and $11.8 million, respectively).

The following table summarizes the cumulative share-based compensation expense recognized to-date which is recorded to Paid-in Capital on the Consolidated Balance Sheets. Unrecognized amounts will be recorded to non-cash share-based compensation expense over the remaining vesting terms.

At September 30, 2017 ($ thousands, except for years)		**PSU(1)**		**RSU**		**Total**
Cumulative recognized share-based compensation expense	$	22,811	$	10,622	$	33,433
Unrecognized share-based compensation expense		9,611		6,699		16,310
Fair value	$	32,422	$	17,321	$	49,743
Weighted-average remaining contractual term (years)		1.6		1.3		

(1) Includes estimated performance multipliers.

ii) Stock Option Plan

The Company suspended the issuance of stock options in 2014. At September 30, 2017 all stock options are fully vested and any related non-cash share-based compensation expense has been fully recognized.

The following table summarizes the stock option plan activity for the nine months ended September 30, 2017:

Period ended September 30, 2017	**Number of Options** (thousands)		**Weighted Average Exercise Price**
Options outstanding, beginning of year	5,900	$	18.29
Forfeited	(371)		18.96
Options outstanding, end of period	5,529	$	18.24
Options exercisable, end of period	5,529	$	18.24

At September 30, 2017, Enerplus had 5,529,451 options that were exercisable at a weighted average exercise price of $18.24 with a weighted average remaining contractual term of 1.8 years, giving an aggregate intrinsic value of nil (2016 – 2.8 years and nil). The intrinsic value of options exercised for both the three and nine months ended September 30, 2017 was nil (September 30, 2016 – nil and nil, respectively).

c) Basic and Diluted Net Income/(Loss) Per Share

Net income/(loss) per share has been determined as follows:

(thousands, except per share amounts)	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
Net income/(loss)	$ 16,131	$ (100,689)	$ 221,726	$ (442,909)
Weighted average shares outstanding – Basic	242,129	240,483	241,854	221,843
Dilutive impact of share-based compensation(1)	5,478	—	5,452	—
Weighted average shares outstanding – Diluted	247,607	240,483	247,306	221,843
Net income/(loss) per share				
Basic	$ 0.07	$ (0.42)	$ 0.92	$ (2.00)
Diluted(1)	$ 0.07	$ (0.42)	$ 0.90	$ (2.00)

(1) For the three and nine months ended September 30, 2016 the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At September 30, 2017 the carrying value of cash, accounts receivable, accounts payable, and dividends payable approximated their fair value due to the short-term maturity of the instruments.

At September 30, 2017 senior notes had a carrying value of $667.3 million and a fair value of $693.5 million (December 31, 2016 - $745.6 million and $771.0 million, respectively).

The fair value of derivative contracts and the senior notes are considered a level 2 fair value measurement. There were no transfers between fair value hierarchy levels during the period.

b) Derivative Financial Instruments

The deferred financial assets and liabilities on the Consolidated Balance Sheets result from recording derivative financial instruments at fair value.

The following table summarizes the change in fair value for the three and nine months ended September 30, 2017 and 2016:

Gain/(Loss) ($ thousands)	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016	Income Statement Presentation
Electricity Swaps	$ 139	$ (25)	$ 409	$ 552	Operating expense
Equity Swaps	827	(58)	(184)	1,597	G&A expense
Commodity Derivative Instruments:					
Oil	(37,465)	(1,684)	34,173	(60,104)	Commodity derivative instruments
Gas	336	3,791	9,399	(7,416)	
Total	$ (36,163)	$ 2,024	$ 43,797	$ (65,371)	

The following table summarizes the income statement effects of Enerplus' commodity derivative instruments:

($ thousands)	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
Change in fair value gain/(loss)	$ (37,129)	$ 2,107	$ 43,572	$ (67,520)
Net realized cash gain/(loss)	2,914	9,965	11,723	71,149
Commodity derivative instruments gain/(loss)	$ (34,215)	$ 12,072	$ 55,295	$ 3,629

The following table summarizes the fair values at the respective period ends:

	September 30, 2017				December 31, 2016	
	Assets		Liabilities		Liabilities	
($ thousands)	Current	Long-term	Current	Long-term	Current	Long-term
Electricity Swaps	$ —	$ —	$ 232	$ —	$ 641	$ —
Equity Swaps	—	—	2,119	—	1,044	891
Commodity Derivative Instruments:						
Oil	9,956	1,562	855	5,331	17,466	11,375
Gas	—	—	65	—	9,464	—
Total	$ 9,956	$ 1,562	$ 3,271	$ 5,331	$ 28,615	$ 12,266

c) Risk Management

i) Market Risk

Market risk is comprised of commodity price, foreign exchange, interest rate and equity price risk.

Commodity Price Risk:

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes net of royalties and production taxes.

The following tables summarize the Corporation's price risk management positions at November 8, 2017:

Crude Oil Instruments:

Instrument Type[(1)]	bbls/day	US$/bbl
Oct 1, 2017 – Dec 31, 2017		
WTI Swap	2,000	53.50
WTI Purchased Put	18,000	50.61
WTI Sold Call	18,000	60.33
WTI Sold Put	18,000	39.62
WCS Differential Swap	3,000	(14.45)
Jan 1, 2018 – Mar 31, 2018		
WTI Swap	3,000	53.73
WTI Purchased Put	13,000	53.04
WTI Sold Call	13,000	61.99
WTI Sold Put	13,000	42.83
WCS Differential Swap	1,500	(14.75)
Apr 1, 2018 – Jun 30, 2018		
WTI Swap	3,000	53.73
WTI Purchased Put	15,000	52.90
WTI Sold Call	15,000	61.73
WTI Sold Put	15,000	42.92
WCS Differential Swap	1,500	(14.75)
Jul 1, 2018 – Sep 30, 2018		
WTI Swap	3,000	53.73
WTI Purchased Put	18,000	52.53
WTI Sold Call	18,000	61.22
WTI Sold Put	18,000	42.71
WCS Differential Swap	1,500	(14.75)
Oct 1, 2018 – Dec 31, 2018		
WTI Swap	3,000	53.73
WTI Purchased Put	20,000	52.48
WTI Sold Call	20,000	61.10
WTI Sold Put	20,000	42.74
WCS Differential Swap	1,500	(14.75)

Jan 1, 2019 – Mar 31, 2019		
WTI Swap	3,000	53.73
WTI Purchased Put	7,000	53.21
WTI Sold Call	7,000	61.14
WTI Sold Put	7,000	43.54
Apr 1, 2019 – Dec 31, 2019		
WTI Purchased Put	10,000	53.53
WTI Sold Call	10,000	62.27
WTI Sold Put	10,000	43.48

(1) Transactions with a common term have been aggregated and presented at a weighted average price/bbl.

Natural Gas Instruments:

Instrument Type(1)	MMcf/day	US$/Mcf
Oct 1, 2017 – Dec 31, 2017		
NYMEX Purchased Put	50.0	2.75
NYMEX Sold Call	50.0	3.41
NYMEX Sold Put	50.0	2.06
Jan 1, 2018 – Dec 31, 2018		
NYMEX Purchased Put	25.0	2.75
NYMEX Sold Call	25.0	3.46

(1) Transactions with a common term have been aggregated and presented at a weighted average price/Mcf.

Electricity Instruments:

Instrument Type	MWh	CDN$/Mwh
Oct 1, 2017 – Dec 31, 2017		
AESO Power Swap(1)	6.0	44.38

(1) Alberta Electrical System Operator ("AESO") fixed pricing.

Physical Contracts:

Instrument Type	MMcf/day	US$/Mcf
Purchases:		
Oct 1, 2017 – Oct 31, 2017 AECO-NYMEX Basis	35.0	(1.14)
Nov 1, 2017 – Nov 30, 2017 AECO-NYMEX Basis	35.0	(1.34)
Sales:		
Oct 1, 2017 – Oct 31, 2017 AECO-NYMEX Basis	35.0	(0.66)
Nov 1, 2017 – Oct 31, 2018 AECO-NYMEX Basis	35.0	(0.66)
Nov 1, 2018 – Oct 31, 2019 AECO-NYMEX Basis	35.0	(0.64)

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations, U.S. dollar denominated senior notes, cash deposits and working capital. Additionally, Enerplus' crude oil sales and a portion of its natural gas sales are based on U.S. dollar indices. To mitigate exposure to fluctuations in foreign exchange, Enerplus may enter into foreign exchange derivatives. At September 30, 2017 Enerplus did not have any foreign exchange derivatives outstanding.

Interest Rate Risk:

As of September 30, 2017 all of Enerplus' debt was based on fixed interest rates, and Enerplus had no interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 14. Enerplus has entered into various equity swaps maturing between 2017 and 2018 and has effectively fixed the future settlement cost on 470,000 shares at weighted average price of $16.89 per share.

ii) Credit Risk

Credit risk represents the financial loss Enerplus would experience due to the potential non-performance of counterparties to its financial instruments. Enerplus is exposed to credit risk mainly through its joint venture, marketing and financial counterparty receivables.

Enerplus mitigates credit risk through credit management techniques including conducting financial assessments to establish and monitor counterparties' credit worthiness, setting exposure limits, monitoring exposures against these limits and obtaining financial assurances such as letters of credit, parental guarantees or third party credit insurance where warranted. Enerplus monitors and manages its concentration of counterparty credit risk on an ongoing basis.

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At September 30, 2017 approximately 66% of Enerplus' marketing receivables were with companies considered investment grade.

Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts of future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectable the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at September 30, 2017 was $3.2 million (December 31, 2016 - $3.3 million).

iii) Liquidity Risk & Capital Management

Liquidity risk represents the risk that Enerplus will be unable to meet its financial obligations as they become due. Enerplus mitigates liquidity risk through actively managing its capital, which it defines as debt (net of cash and restricted cash) and shareholders' capital. Enerplus' objective is to provide adequate short and long term liquidity while maintaining a flexible capital structure to sustain the future development of its business. Enerplus strives to balance the portion of debt and equity in its capital structure given its current oil and natural gas assets and planned investment opportunities.

Management monitors a number of key variables with respect to its capital structure, including debt levels, capital spending plans, dividends, access to capital markets, and acquisition and divestment activity.

At September 30, 2017 Enerplus was in full compliance with all covenants under the bank credit facility and outstanding senior notes.

16) CONTINGENCIES

Enerplus is subject to various legal claims and actions arising in the normal course of business. Although the outcome of such claims and actions cannot be predicted with certainty, the Company does not expect these matters to have a material impact on the Consolidated Financial Statements. In instances where the Company determines that a loss is probable and the amount can be reasonably estimated, an accrual is recorded.

17) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2017	2016	2017	2016
Accounts receivable	$ 11,217	$ 20,255	$ 29,272	$ 49,895
Other current assets	(3,406)	3,401	(5,947)	3,305
Accounts payable	19,439	3,421	87	(9,059)
	$ 27,250	$ 27,077	$ 23,412	$ 44,141

b) Other

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2017	2016	2017	2016
Income taxes paid/(received)	$ 776	$ 42	$ 2,715	$ (19,076)
Interest paid	2,762	3,221	23,213	30,859

BOARD OF DIRECTORS

Elliott Pew[1][2]
Corporate Director
Boerne, Texas

David H. Barr[9][12]
Corporate Director
The Woodlands, Texas

Michael R. Culbert[3][5][10]
Corporate Director
Calgary, Alberta

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

Hilary A. Foulkes[3][7][9][11]
Corporate Director
Calgary, Alberta

Robert B. Hodgins[3][6]
Corporate Director
Calgary, Alberta

Susan M. MacKenzie[5][7][11]
Corporate Director
Calgary, Alberta

Glen D. Roane[4][5]
Corporate Director
Canmore, Alberta

Sheldon B. Steeves[5][8]
Corporate Director
Calgary, Alberta

(1) Chairman of the Board
(2) *Ex-Officio* member of all Committees of the Board
(3) Member of the Corporate Governance & Nominating Committee
(4) Chair of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chair of the Audit & Risk Management Committee
(7) Member of the Reserves Committee
(8) Chair of the Reserves Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chair of the Compensation & Human Resources Committee
(11) Member of the Safety & Social Responsibility Committee
(12) Chair of the Safety & Social Responsibility Committee

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas
President & Chief Executive Officer

Raymond J. Daniels
Senior Vice President, Operations, People & Culture

Jodine J. Jenson Labrie
Senior Vice President & Chief Financial Officer

Eric G. Le Dain
Senior Vice President, Corporate Development, Commercial

Nathan D. Fisher
Vice President, U.S. Development & Geosciences

Daniel J. Fitzgerald
Vice President, Business Development

John E. Hoffman
Vice President, Canadian Operations

David A. McCoy
Vice President, General Counsel & Corporate Secretary

Edward L. McLaughlin
President, U.S. Operations

Shaina B. Morihira
Corporate Controller

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION

Enerplus Resources (USA) Corporation

LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Calgary, Alberta

AUDITORS

KPMG LLP
Calgary, Alberta

TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta
Toll free: 1.866.921.0978

U.S. CO-TRANSFER AGENT

Computershare Trust Company, N.A.
Golden, Colorado

INDEPENDENT RESERVE ENGINEERS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

Toronto Stock Exchange: ERF
New York Stock Exchange: ERF

U.S. OFFICE

950 17th Street, Suite 2200
Denver, Colorado 80202

Telephone: 720.279.5500
Fax: 720.279.5550

ABBREVIATIONS

AECO	a reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices
bbl(s)/day	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
Bcf	billion cubic feet
Bcfe	billion cubic feet equivalent
BOE	barrels of oil equivalent
Brent	crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $US dollars
LTI	long-term incentive
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf	million cubic feet
MSW	mixed sweet blend
MWh	megawatt hour(s) of electricity
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange, the benchmark for North American natural gas pricing
OCI	other comprehensive income
SBC	share based compensation
SDP	stock dividend program
U.S. GAAP	accounting principles generally accepted in the United States of America
WCS	Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

Toll Free 1-800-319-6462
www.enerplus.com
investorrelations@enerplus.com

The Dome Tower
3000, 333-7th Avenue SW
Calgary, Alberta T2P 2Z1