enerPLUS

Q2 2017 Second Quarter Report

Six Months Ended June 30, 2017

SELECTED FINANCIAL RESULTS	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Financial (000's)				
Adjusted Funds Flow[4]	$ 114,199	$ 76,047	$ 234,119	$ 117,774
Dividends to Shareholders	7,264	6,547	14,505	21,011
Net Income/(Loss)	129,302	(168,554)	205,595	(342,220)
Debt Outstanding – net of Cash	308,067	674,147	308,067	674,147
Capital Spending	101,739	48,120	222,086	91,396
Property and Land Acquisitions	4,713	343	7,249	3,897
Property Divestments	59,842	92,735	58,942	280,503
Net Debt to Adjusted Funds Flow Ratio[4]	0.7x	2.0x	0.7x	2.0x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss)	$ 0.53	$ (0.77)	$ 0.85	$ (1.61)
Weighted Average Number of Shares Outstanding (000's)	242,127	218,128	241,710	212,420
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 35.96	$ 24.96	$ 36.14	$ 21.99
Royalties and Production Taxes	(8.95)	(5.51)	(8.42)	(4.72)
Commodity Derivative Instruments	0.28	2.53	0.57	3.51
Cash Operating Expenses	(5.88)	(7.20)	(6.23)	(7.67)
Transportation Costs	(3.72)	(2.87)	(3.80)	(2.88)
General and Administrative Expenses	(1.53)	(1.71)	(1.69)	(1.89)
Cash Share-Based Compensation	—	(0.09)	(0.01)	(0.09)
Interest, Foreign Exchange and Other Expenses	(1.34)	(1.21)	(1.31)	(1.51)
Current Income Tax Recovery/(Expense)	(0.26)	0.02	(0.14)	0.02
Adjusted Funds Flow[4]	$ 14.56	$ 8.92	$ 15.11	$ 6.76

SELECTED OPERATING RESULTS	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Average Daily Production[2]				
Crude Oil (bbls/day)	36,861	39,079	35,030	39,294
Natural Gas Liquids (bbls/day)	4,133	4,829	3,648	5,161
Natural Gas (Mcf/day)	271,292	298,503	281,393	307,827
Total (BOE/day)	86,209	93,659	85,577	95,759
% Crude Oil and Natural Gas Liquids	48%	47%	45%	46%
Average Selling Price [2][3]				
Crude Oil (per bbl)	$ 55.66	$ 46.48	$ 56.54	$ 39.00
Natural Gas Liquids (per bbl)	25.14	15.67	30.57	13.37
Natural Gas (per Mcf)	3.48	1.49	3.56	1.64
Net Wells Drilled	13	5	28	17

(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 June 30, 2017	2016	Six months ended June 30, 2017	2016
WTI crude oil (US$/bbl)	$ 48.29	$ 45.59	$ 50.10	$ 39.52
AECO natural gas– monthly index (CDN$/Mcf)	2.77	1.25	2.86	1.68
AECO natural gas – daily index (CDN$/Mcf)	2.78	1.40	2.74	1.62
NYMEX natural gas – last day (US$/Mcf)	3.18	1.95	3.25	2.02
USD/CDN average exchange rate	1.34	1.29	1.33	1.33

Share Trading Summary For the three months ended June 30, 2017	CDN[1] - ERF (CDN$)	U.S. [2] - ERF (US$)
High	$ 11.48	$ 8.54
Low	$ 8.97	$ 6.52
Close	$ 10.52	$ 8.12

(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
Total Year to Date	$ 0.06	$ 0.04

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

NEWS RELEASE

Highlights:

- 35% production growth in North Dakota quarter-over-quarter
- Generated adjusted funds flow of $114.2 million
- Increasing 2017 production guidance to 84,000 – 86,000 BOE per day
- 12% reduction in operating expenses quarter-over-quarter, 19% reduction year-over-year
- Lowering operating, cash G&A, and transportation expense guidance by a total of $0.65 per BOE

"Our second quarter results demonstrate the oil production growth potential of our high-quality position at Fort Berthold, where we remain on track to deliver 50% production growth over the course of 2017," stated Ian C. Dundas, President and Chief Executive Officer. "Additionally, our focus on cost management and commitment to maintaining our strong financial footing continues to position Enerplus to deliver sustained, long-term profitable growth in a lower commodity price environment."

Financial and Operational Summary

Second quarter 2017 production averaged 86,209 BOE per day, including 40,994 barrels per day of crude oil and natural gas liquids. Liquids production increased to 48% of total company production, growing 13% from the first quarter driven by strong North Dakota volumes. Operations in North Dakota have been trending ahead of schedule which, combined with continued strong well performance, helped deliver second quarter North Dakota production of 28,047 BOE per day, a 35% increase from the previous quarter.

Enerplus is increasing its 2017 annual average production guidance range to 84,000 to 86,000 BOE per day (from 81,000 to 85,000 BOE per day) and its 2017 annual average liquids guidance to 39,500 to 41,500 barrels per day (from 38,500 to 41,500 barrels per day).

During the second quarter, Enerplus closed the previously announced divestment of shallow gas assets in Canada and its Brooks waterflood property with combined production of approximately 5,600 BOE per day. Second quarter production also included approximately 6 MMcf per day related to a Marcellus gas balancing adjustment. Production in the third quarter is expected to be sequentially lower due to this divestment and the gas balancing adjustment, combined with fewer wells planned to be brought on-stream in North Dakota and the Marcellus relative to the second quarter. Production is expected to significantly build later in the year with capital activity in the third quarter driving strong volumes into the fourth quarter. Enerplus remains well positioned to achieve its fourth quarter production guidance of 86,000 to 91,000 BOE per day including 43,000 to 48,000 barrels per day of liquids.

Enerplus generated adjusted funds flow of $114.2 million, a 5% decrease from the previous quarter as a result of lower commodity prices, which was offset by strong liquids production growth out of North Dakota, and reduced operating and G&A expenses during the quarter.

Exploration and development capital spending in the second quarter of 2017 was $101.7 million, with $70.7 million directed to North Dakota, $9.9 million allocated to the Canadian waterfloods, and $17.5 million directed to the Marcellus. Enerplus' 2017 exploration and development capital budget of $450 million is unchanged.

Enerplus' commodity hedging program realized cash gains of $2.2 million for the second quarter of 2017, compared to cash gains of $6.6 million in the first quarter of 2017.

Enerplus' realized Bakken crude oil price differential averaged US$5.43 per barrel below WTI in the second quarter, a 3% improvement relative to the previous quarter. Spot Bakken prices strengthened considerably late in the second quarter and into the third quarter as the Dakota Access Pipeline was brought into service in June. Based on this ongoing strength in pricing, Enerplus continues to expect its Bakken crude oil differential to average approximately US$4.50 per barrel below WTI during 2017.

Enerplus' realized Marcellus natural gas sales price differential widened slightly to US$0.64 per Mcf below NYMEX in the second quarter compared to US$0.60 per Mcf in the previous quarter. Regulatory issues announced in May have delayed the construction of the Rover pipeline project that will transport gas from the Marcellus/Utica region into the U.S. Midwest and Eastern Canada. Combined with higher production in the region relative to the previous quarter, this delay weakened regional market prices, pushing Marcellus basis differentials wider late in the quarter. Considering the uncertainty in the timing of the in-service date of the Rover pipeline, Enerplus now expects its Marcellus natural gas realized price differential to average US$0.75 per Mcf below NYMEX for 2017 (compared to US$0.60 per Mcf previously). Enerplus expects its Marcellus price differentials will continue to narrow once Rover and other pipeline projects slated for completion in the second half of 2017 are in-service, with a view to more consistent differentials and improved pricing moving into 2018.

Second quarter operating expenses averaged $5.83 per BOE, 12% lower compared to the prior quarter. Operating expenses continued to improve in the second quarter largely due to additional savings from the 2017 divestment program. As a result, Enerplus is lowering its 2017 operating expense guidance to $6.40 per BOE, from $6.85 per BOE. Enerplus expects operating costs to increase over the remainder of 2017 as its liquids production weighting increases.

Transportation costs in the second quarter averaged $3.72 per BOE, a decrease from $3.88 per BOE in the first quarter of 2017. Enerplus is reducing its 2017 guidance for transportation costs to $3.90 per BOE, from $4.00 per BOE, due to the impact of lower than expected USD/CDN foreign exchange rates on U.S. transportation costs and the increase in the Company's annual production guidance.

Cash G&A expenses were $1.53 per BOE for the quarter, compared to $1.87 per BOE in the previous quarter. The decrease in cash G&A expenses was due to continued cost savings initiatives and the impact of reductions in staffing levels following asset divestments during the year. Enerplus is reducing its cash G&A expense guidance to $1.75 per BOE, from $1.85 per BOE.

Enerplus remains in a strong financial position. Total debt net of cash at June 30, 2017 was $308.1 million. Total debt was comprised of $693.1 million of senior notes outstanding. The Company was undrawn on its $800 million bank credit facility, and had a cash balance of $385.1 million. At June 30, 2017, Enerplus' net debt to adjusted funds flow ratio was 0.7 times.

Average Daily Production(1)

	Three months ended June 30, 2017			Six months ended June 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	28.9	19.9	32.2	25.5	19.1	28.7
Marcellus	—	204.7	34.1	—	204.7	34.1
Canadian Waterfloods(2)	11.0	13.0	13.1	12.0	16.9	14.8
Other(2)	1.1	33.8	6.7	1.2	40.7	8.0
Total	41.0	271.3	86.2	38.7	281.4	85.6

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

Summary of Wells Brought On-Stream(1)

	Three months ended June 30, 2017				Six months ended June 30, 2017			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	11.0	8.1	1.0	0.5	19.0	14.8	1.0	0.5
Marcellus	—	—	13.0	2.3	—	—	27.0	3.1
Canadian Waterfloods	3.0	3.0	—	—	5.0	5.0	—	—
Total	14.0	11.1	14.0	2.7	24.0	19.8	28.0	3.6

(1) Table may not add due to rounding.

Asset Activity

WILLISTON BASIN

Williston Basin production averaged 32,240 BOE per day (90% liquids) during the second quarter of 2017, a 29% increase compared to the prior quarter. Second quarter Williston Basin production was comprised of 28,047 BOE per day in North Dakota, a 35% increase from the prior quarter, and 4,193 BOE per day in Montana, approximately flat to the prior quarter.

In the second quarter, Enerplus brought on-stream 11 gross operated wells (74% average working interest) across its acreage at Fort Berthold. Of note is the Arctic 94-36BH well which has continued to produce at strong rates after three months on production. The well has delivered a peak 90-day production rate of 1,250 BOE per day. This 4,300 foot lateral well was completed with a proppant volume of approximately 2,300 pounds per foot, higher than Enerplus' base completion design of 1,000 pounds per foot. Two wells were brought on production from the Marsupials pad with an average lateral length of 4,300 feet and an average peak 30-day production rate per well of 1,318 BOE per day. Four wells on the Mountains pad were brought on production with an average lateral length of 9,300 feet and an average peak 30-day production rate per well of 1,275 BOE per day.

The Company drilled 10 gross operated wells (85% average working interest) in the second quarter, including a 20,000 ft. (10,000 ft. lateral) well drilled in under 12 days from spud to rig release, a new record for the Company. This represents an 18% improvement in drilling days compared to the Company's previous fastest drill.

MARCELLUS

Marcellus production averaged 205 MMcf per day during the second quarter of 2017, approximately flat to the previous quarter. Production volumes in the quarter included approximately 6 MMcf per day related to a gas balancing adjustment. Thirteen gross non-operated wells (18% average working interest) were brought on-stream during the second quarter of 2017. Twelve of these wells had more than 30 days on production as of the date of this news release with an average lateral length of 4,900 feet per well and an average peak 30-day production rate per well of 13.2 MMcf per day.

The Company participated in drilling 13 gross non-operated wells (18% average working interest) during the second quarter.

CANADIAN WATERFLOODS

Canadian waterflood production averaged 13,144 BOE per day (83% liquids) during the second quarter of 2017, a decrease of 20% from the previous quarter primarily due to the divestment of the Brooks property during the quarter. Activity in the quarter was largely focused at Ante Creek with the continued advancement of waterflood implementation across the field. Water injection has been increased from 1,000 barrels of water per day in January 2017 to over 5,000 barrels of water per day currently, with a target injection of 12,000 to 15,000 barrels of water per day by year-end.

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, net of royalties), 18,000 barrels per day of crude oil protected in 2018, and 4,000 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 net of royalties) using collar structures.

Commodity Hedging Detail (As at August 10, 2017)

	WTI Crude Oil (US$/bbl)[1]					NYMEX Natural Gas (US$/Mcf)[1]
	Jul 1, 2017 – Dec 31, 2017	Jan 1, 2018 – Jun 30, 2018	Jul 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Dec 31, 2019	Jul 1, 2017 – Dec 31, 2017
Swaps						
Sold Swaps	$ 53.50	$ 53.73	$ 53.73	$ 53.73	$ —	$ —
Volume (bbls/d or Mcf/d)	2,000	3,000	3,000	3,000	—	—
Three Way Collars						
Sold Puts	$ 39.62	$ 42.83	$ 42.63	$ 45.00	$ 43.75	$ 2.06
Volume (bbls/d or Mcf/d)	18,000	13,000	17,000	1,000	4,000	50,000
Purchased Puts	$ 50.61	$ 53.04	$ 52.56	$ 56.00	$ 54.69	$ 2.75
Volume (bbls/d or Mcf/d)	18,000	13,000	17,000	1,000	4,000	50,000
Sold Calls	$ 60.33	$ 61.99	$ 61.29	$ 70.00	$ 66.18	$ 3.41
Volume (bbls/d or Mcf/d)	18,000	13,000	17,000	1,000	4,000	50,000

(1) Based on weighted average price (before premiums) assuming annual average production of 85,000 BOE/day, net of royalties and production taxes of 24%.

2017 Updated Guidance

Enerplus' updated 2017 guidance is summarized below.

	Guidance
Capital spending	$450 million
Average annual production	84,000 – 86,000 BOE/day (from 81,000 - 85,000 BOE/day)
Q4 average production	86,000 – 91,000 BOE/day
Average annual crude oil and natural gas liquids production	39,500 – 41,500 bbls/day (from 38,500 – 41,500 bbls/day)
Q4 average crude oil and natural gas liquids production	43,000 – 48,000 bbls/day
Average royalty and production tax rate	24%
Operating expense	$6.40/BOE (from $6.85/BOE)
Transportation expense	$3.90/BOE (from $4.00/BOE)
Cash G&A expense	$1.75/BOE (from $1.85/BOE)

Differential/Basis Outlook[1]	
2017 Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(4.50) per bbl
2017 Average Marcellus basis (compared to NYMEX natural gas)	US$(0.75) per Mcf (from US$(0.60) per Mcf)

(1) Excluding transportation costs.

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 proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management programs in 2017 and beyond; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash and non-cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2017 and its impact on our production level and land holdings; our 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 $2.40/GJ and a USD/CDN exchange rate of 1.30. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this 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' Second Quarter 2017 MD&A.

Electronic copies of Enerplus Corporation's Second 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 August 10, 2017 and is to be read in conjunction with:

- the unaudited interim consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three and six months ended June 30, 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

Second quarter production averaged 86,209 BOE/day, compared to our annual average production guidance range of 81,000 – 85,000 BOE/day. As a result of our successful capital development program to date, we are increasing our annual guidance range to 84,000 – 86,000 BOE/day. Production increased by 2% when compared to the first quarter of 2017, which includes the impact of Canadian asset divestments completed during the first and second quarter of 2017 with combined production of 7,300 BOE/day. These divestments were offset by a 35% increase in North Dakota production with 8.6 net wells coming on-stream during the second quarter. With the growth in North Dakota, we produced 40,994 bbls/day of crude oil and natural gas liquids in the quarter, up from 36,336 bbls/day in the first quarter. As a result, we are raising the lower end of our crude oil and natural gas liquids range, and are now guiding to 39,500 – 41,500 bbls/day. We are maintaining our fourth quarter exit production guidance of 86,000 – 91,000 BOE/day and fourth quarter average crude oil and natural gas liquids range of 43,000 – 48,000 bbls/day.

Our capital spending for the second quarter totaled $101.7 million, which was in line with expectations. Approximately 70% of our capital program was directed to our North Dakota crude oil properties, 17% to our Marcellus natural gas asset and 10% to our Canadian waterfloods. We are maintaining our 2017 annual capital spending guidance of $450 million.

Operating expenses were $45.8 million or $5.83/BOE during the second quarter compared to our annual guidance of $6.85/BOE. The decrease in operating costs from the first quarter of 2017 was mainly due to additional savings related to the previously announced divestment of higher operating cost Canadian assets, as well as strong production performance in Fort Berthold and Marcellus. As a result, we are reducing our annual guidance for operating expenses to $6.40/BOE from $6.85/BOE. We expect higher operating costs for the second half of the year as our liquids production weighting increases.

Cash G&A expenses for the second quarter were $12.0 million or $1.53/BOE compared to annual guidance of $1.85/BOE. The decrease in our cash G&A expenses is primarily due to reductions in staff levels as we continue to focus the business through asset divestments, along with higher production during the quarter. Accordingly, we are lowering our cash G&A expense guidance to $1.75/BOE from $1.85/BOE. We are also reducing our transportation guidance to $3.90/BOE from $4.00/BOE.

During the quarter we closed the previously announced sale of Alberta shallow gas assets and the Brooks waterflood property for proceeds of $59.6 million, with associated production of 5,600 BOE/day and asset retirement obligations of $46.9 million. Second quarter earnings includes a gain of $78.4 million related to this divestment.

We continued to add to our commodity hedge positions during the quarter. As of August 10, 2017, we have approximately 72% of our forecasted crude oil production, net of royalties, hedged for the remainder of 2017, and approximately 65% and 15% 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.

We recorded net income of $129.3 million and adjusted funds flow of $114.2 million in the second quarter, compared to $76.3 million and $119.9 million, respectively, in the first quarter of 2017. Both net income and adjusted funds flow benefited from the impact of increased volumes, as well as reductions in cash operating and G&A expenses. Net income also included the gain on our second quarter asset divestment.

At June 30, 2017, our total debt net of cash decreased to $308.1 million and our net debt to adjusted funds flow ratio was 0.7x.

RESULTS OF OPERATIONS

Production

Production for the second quarter averaged 86,209 BOE/day, an increase of 1,272 BOE/day or 2% compared to the first quarter of 2017, despite the second quarter sale of certain Canadian assets with production of approximately 5,600 BOE/day. The strong performance from our Fort Berthold and Marcellus assets, a significant number of on-streams in North Dakota during the quarter, and a gas balancing adjustment related to our Marcellus assets contributed to higher production levels. Crude oil and liquids production increased by 4,658 bbls/day or 13% during the quarter, primarily due to 8.6 additional net wells brought on-stream in Fort Berthold as we continue to execute on our capital program. Natural gas production decreased by 7% from the first quarter, which was primarily due to the divestments in Canada which closed throughout the first and second quarters of 2017. As a result, our crude oil and natural gas liquids weighting during the second quarter increased to 48% from 43% in the first quarter of 2017.

For the three months ended June 30, 2017, crude oil and natural gas liquids volumes decreased by 2,914 bbls/day or 7% compared to the same period in the prior year. This was primarily due to the divestment of 5,000 BOE/day of our non-operated North Dakota assets on December 30, 2016, and the second quarter 2017 divestment of the Brooks waterflood property with approximately 1,800 bbls/day of crude oil and liquids production, partially offset by production growth out of North Dakota. Natural gas production decreased by 27,211 Mcf/day or 9% compared to the same period in 2016, as a result of the asset divestments in Canada from the third quarter of 2016 through the second quarter of 2017.

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

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2017**	**2016**	**% Change**	**2017**	**2016**	**% Change**
Crude oil (bbls/day)	36,861	39,079	(6%)	35,030	39,294	(11%)
Natural gas liquids (bbls/day)	4,133	4,829	(14%)	3,648	5,161	(29%)
Natural gas (Mcf/day)	271,292	298,503	(9%)	281,393	307,827	(9%)
Total daily sales (BOE/day)	86,209	93,659	(8%)	85,577	95,759	(11%)

As a result of our successful capital development program, we are increasing our annual average production guidance to 84,000 – 86,000 BOE/day from 81,000 – 85,000 BOE/day, and raising the lower end of our crude oil and natural gas liquids guidance range to 39,500 – 41,500 bbls/day from 38,500 – 41,500 bbls/day. This guidance assumes lower third quarter production with the majority of our remaining 2017 North Dakota on-streams scheduled for the fourth quarter, as well as the full impact of divestments completed to date. We are maintaining our fourth quarter exit guidance targets with average production of 86,000 – 91,000 BOE/day and average crude oil and natural gas liquids of 43,000 – 48,000 bbls/day.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, adjusted funds flow and financial condition. The following table compares quarterly average prices from the first half of 2017 to the first half of 2016 and other periods indicated:

	Six months ended June 30,						
Pricing (average for the period)	**2017**	**2016**	**Q2 2017**	**Q1 2017**	**Q4 2016**	**Q3 2016**	**Q2 2016**
Benchmarks							
WTI crude oil (US$/bbl)	$ 50.10	$ 39.52	$ 48.29	$ 51.92	$ 49.29	$ 44.94	$ 45.59
AECO natural gas – monthly index ($/Mcf)	2.86	1.68	2.77	2.94	2.81	2.20	1.25
AECO natural gas – daily index ($/Mcf)	2.74	1.62	2.78	2.69	3.09	2.32	1.40
NYMEX natural gas – last day (US$/Mcf)	3.25	2.02	3.18	3.32	2.98	2.81	1.95
USD/CDN average exchange rate	1.33	1.33	1.34	1.32	1.33	1.31	1.29
USD/CDN period end exchange rate	1.30	1.30	1.30	1.33	1.34	1.31	1.30
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 56.54	$ 39.00	$ 55.66	$ 57.53	$ 53.91	$ 47.93	$ 46.48
Natural gas liquids ($/bbl)	30.57	13.37	25.14	37.76	21.31	13.85	15.67
Natural gas ($/Mcf)	3.56	1.64	3.48	3.63	2.89	2.12	1.49
Average differentials							
MSW Edmonton – WTI (US$/bbl)	$ (2.90)	$ (3.39)	$ (2.26)	$ (3.54)	$ (3.11)	$ (2.96)	$ (3.09)
WCS Hardisty – WTI (US$/bbl)	(12.85)	(13.77)	(11.13)	(14.58)	(14.32)	(13.50)	(13.30)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.61)	(0.84)	(0.60)	(0.63)	(1.58)	(1.35)	(0.70)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.68)	(0.90)	(0.66)	(0.70)	(1.64)	(1.40)	(0.73)
AECO monthly – NYMEX (US$/Mcf)	(1.12)	(0.76)	(1.13)	(1.10)	(0.86)	(1.13)	(0.99)
Enerplus realized differentials (1)(2)							
Canada crude oil – WTI (US$/bbl)	$ (11.95)	$ (13.46)	$ (11.02)	$ (12.76)	$ (12.97)	$ (12.06)	$ (12.01)
Canada natural gas – NYMEX (US$/Mcf)	(0.56)	(0.74)	(0.51)	(0.56)	(0.63)	(0.92)	(0.86)
Bakken crude oil – WTI (US$/bbl)	(5.49)	(8.29)	(5.43)	(5.59)	(6.80)	(6.39)	(8.23)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.62)	(0.83)	(0.64)	(0.60)	(0.88)	(1.19)	(0.76)

(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 during the quarter decreased by 3% to average $55.66/bbl, compared to a 7% decrease in benchmark WTI prices.

Bakken price differentials to WTI improved by 3% during the quarter to average US$5.43/bbl below WTI. Spot Bakken prices strengthened considerably late in the second quarter and into the third quarter as the Dakota Access Pipeline was brought into service in early June. However, during the second quarter we had a higher proportion of our crude oil production trucked from new pads brought on-stream which contributed to a wider differential than the spot pricing. Based on the ongoing strength we are seeing in the Bakken market, we continue to expect our Bakken crude oil differential to average US$4.50/bbl below WTI for 2017.

Our realized price differential for our Canadian crude oil production improved by 14% compared to the previous quarter, due largely to strength in Canadian light and heavy crude oil benchmark prices which were impacted by ongoing regional oil sands production outages. Our realized price for natural gas liquids averaged $25.14/bbl during the period, a decrease of 33% compared to the previous quarter. Both Canadian and U.S. natural gas liquids prices fell in the second quarter with lower demand.

NATURAL GAS

Our average realized natural gas price during the second quarter decreased by 4% compared to the first quarter to average $3.48/Mcf. Benchmark NYMEX natural gas prices also decreased by 4% during the quarter due to higher U.S. gas production.

Our realized Marcellus sales price differential excluding transportation and gathering widened during the quarter to average US$0.64/Mcf below NYMEX. Benchmark monthly Transco Leidy prices averaged US$0.60/Mcf below NYMEX during the second quarter. Regulatory concerns announced in May are expected to delay the targeted completion of the construction of the Rover pipeline project that will transport gas from the Marcellus/Utica region into the U.S. Midwest and Eastern Canada. Combined with higher production in the region relative to the previous quarter, these anticipated delays resulted in weakness in regional basis markets in the Marcellus pushing differentials wider late in the quarter. As a result, we expect our Marcellus natural gas realized price differential to now average US$0.75/Mcf below NYMEX for 2017. Once Rover and other pipeline projects slated for completion in 2017 are in-service, we expect Marcellus price differentials to improve.

Most of our Canadian gas production is sold under multi-year fixed AECO basis differential contracts at prices higher than those currently realized in the spot market. Our realized Canadian gas price differential averaged US$0.51/Mcf below NYMEX compared to the AECO benchmark monthly price that averaged US$1.13/Mcf below NYMEX in the second quarter.

FOREIGN EXCHANGE

The USD/CDN exchange rate was 1.30 USD/CDN at June 30, 2017, and averaged 1.34 USD/CDN during the second quarter of 2017 compared to average rates of 1.32 USD/CDN during the first quarter of 2017, and USD/CDN 1.29 during the second quarter of 2016. The majority of our oil and natural gas sales are based on U.S. dollar denominated indices, and a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. Because we report in Canadian dollars, the 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 August 10, 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 18,000 bbls/day, which represents approximately 65% of our 2017 forecasted crude oil production, after royalties. For 2019, we have hedged 4,000 bbls/day, which represents approximately 15% of our 2017 forecasted crude oil production. 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 in any given month, the three way collars provide a limited amount of protection above the WTI settled price equal to the difference between the strike price of the purchased and sold puts. Overall, we expect our crude oil related hedging contracts to protect a significant portion of our funds flow.

As of August 10, 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. Note that all of our NYMEX gas hedges have been transacted using a three way collar structure. When NYMEX prices settle below the sold put strike price in any given month, the three way collars provide a limited amount of protection above the NYMEX settled price equal to the difference between the strike price of the purchased and sold puts.

The following is a summary of our financial contracts in place at August 10, 2017, expressed as a percentage of our forecasted 2017 net production volumes:

	WTI Crude Oil (US$/bbl)(1)					NYMEX Natural Gas (US$/Mcf)(1)
	Jul 1, 2017 – Dec 31, 2017	Jan 1, 2018 – Jun 30, 2018	Jul 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Dec 31, 2019	Jul 1, 2017 – Dec 31, 2017
Swaps						
Sold Swaps	$ 53.50	$ 53.73	$ 53.73	$ 53.73	—	—
%	7%	11%	11%	11%	—	—
Three Way Collars						
Sold Puts	$ 39.62	$ 42.83	$ 42.63	$ 45.00	$ 43.75	$ 2.06
%	65%	47%	62%	4%	15%	25%
Purchased Puts	$ 50.61	$ 53.04	$ 52.56	$ 56.00	$ 54.69	$ 2.75
%	65%	47%	62%	4%	15%	25%
Sold Calls	$ 60.33	$ 61.99	$ 61.29	$ 70.00	$ 66.18	$ 3.41
%	65%	47%	62%	4%	15%	25%

(1) Based on weighted average price (before premiums) assuming average annual production of 85,000 BOE/day less royalties and production taxes of 24%.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses) ($ millions)	**Three months ended June 30,** **2017**	 **2016**	**Six months ended June 30,** **2017**	 **2016**
Cash gains/(losses):				
Crude oil	$ 2.2	$ 16.4	$ 1.3	$ 52.9
Natural gas	—	5.2	7.5	8.3
Total cash gains/(losses)	$ 2.2	$ 21.6	$ 8.8	$ 61.2
Non-cash gains/(losses):				
Crude oil	$ 27.3	$ (27.2)	$ 71.6	$ (58.4)
Natural gas	2.4	(16.3)	9.1	(11.2)
Total non-cash gains/(losses)	$ 29.7	$ (43.5)	$ 80.7	$ (69.6)
Total gains/(losses)	$ 31.9	$ (21.9)	$ 89.5	$ (8.4)

(Per BOE)	**Three months ended June 30,** **2017**	 **2016**	**Six months ended June 30,** **2017**	 **2016**
Total cash gains/(losses)	$ 0.28	$ 2.53	$ 0.57	$ 3.51
Total non-cash gains/(losses)	3.79	(5.10)	5.21	(3.99)
Total gains/(losses)	$ 4.07	$ (2.57)	$ 5.78	$ (0.48)

During the second quarter of 2017 we realized cash gains of $2.2 million on our crude oil contracts. In comparison, during the second quarter of 2016 we realized cash gains of $16.4 million on our crude oil contracts and $5.2 million on our natural gas contracts. 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 second quarter of 2017, the fair value of our crude oil contracts was in a net asset position of $42.8 million, while the fair value of our natural gas contracts was in a net liability position of $0.4 million. For the three and six months ended June 30, 2017, the change in the fair value of our crude oil contracts represented gains of $27.3 million and $71.6 million, respectively, and our natural gas contracts represented gains of $2.4 million and $9.1 million, respectively.

Revenues

($ millions)	**Three months ended June 30,** **2017**	 **2016**	**Six months ended June 30,** **2017**	 **2016**
Oil and natural gas sales	$ 282.1	$ 212.7	$ 559.8	$ 383.2
Royalties	(56.4)	(38.4)	(106.3)	(66.2)
Oil and natural gas sales, net of royalties	$ 225.7	$ 174.3	$ 453.5	$ 317.0

Oil and natural gas sales for the three and six months ended June 30, 2017 were $282.1 million and $559.8 million, respectively, an increase of 33% and 46% from the same periods in 2016. The increase in revenue primarily resulted from higher commodity pricing for both oil and natural gas compared to the same periods in 2016, which more than offset the impact of lower production volumes with asset divestments.

Royalties and Production Taxes

($ millions, except per BOE amounts)	**Three months ended June 30,** **2017**	 **2016**	**Six months ended June 30,** **2017**	 **2016**
Royalties	$ 56.4	$ 38.4	$ 106.3	$ 66.2
Per BOE	$ 7.19	$ 4.51	$ 6.86	$ 3.80
Production taxes	$ 13.8	$ 8.6	$ 24.2	$ 16.0
Per BOE	$ 1.76	$ 1.00	$ 1.56	$ 0.92
Royalties and production taxes	$ 70.2	$ 47.0	$ 130.5	$ 82.2
Per BOE	$ 8.95	$ 5.51	$ 8.42	$ 4.72
Royalties and production taxes (% of oil and natural gas sales)	25%	22%	23%	21%

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 six months ended June 30, 2017, royalties and production taxes increased to $70.2 million and $130.5 million, respectively, from $47.0 million and $82.2 million for the same periods in 2016 primarily due to higher commodity prices. In the second quarter of 2017, royalties and production taxes averaged 25% of crude oil and natural gas sales before transportation primarily due to annual provincial royalty adjustments and a greater weighting of our production coming from our U.S. properties with higher overall royalty rates.

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

Operating Expenses

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2017	2016	2017	2016
Cash operating expenses	$ 46.2	$ 61.4	$ 96.4	$ 133.7
Non-cash (gains)/losses[1]	(0.4)	(0.9)	(0.3)	(0.6)
Total operating expenses	$ 45.8	$ 60.5	$ 96.1	$ 133.1
Per BOE	$ 5.83	$ 7.10	$ 6.21	$ 7.64

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

For the three and six months ended June 30, 2017, operating expenses were $45.8 million ($5.83/BOE) and $96.1 million ($6.21/BOE), respectively, compared to our annual guidance of $6.85/BOE. Operating costs are lower by $14.7 million and $37.0 million relative to the same respective periods in 2016 and nearly 20% lower on a per BOE basis, mainly due to the divestment of higher operating cost Canadian properties throughout 2016 and into 2017, reduced activity levels, and cost savings initiatives.

As a result, we are lowering our annual guidance for operating expenses to $6.40/BOE from $6.85/BOE.

Transportation Costs

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2017	2016	2017	2016
Transportation costs	$ 29.2	$ 24.5	$ 58.8	$ 50.2
Per BOE	$ 3.72	$ 2.87	$ 3.80	$ 2.88

For the three and six months ended June 30, 2017, transportation costs were $29.2 million ($3.72/BOE) and $58.8 million ($3.80/BOE), respectively, relative to our annual guidance target of $4.00/BOE. During the same periods in 2016 transportation costs were $24.5 million ($2.87/BOE) and $50.2 million ($2.88/BOE). 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 U.S. production volumes which have higher associated transportation costs.

We are revising our annual guidance for transportation costs to $3.90/BOE from $4.00/BOE due to the impact of lower expected USD/CDN foreign exchange rates on U.S. transportation costs and the increase in our annual average production.

Netbacks

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

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

Netbacks by Property Type	Three months ended June 30, 2016 Crude Oil		Natural Gas		Total
Average Daily Production	46,972 BOE/day		280,122 Mcfe/day		93,659 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)		(per Mcfe)		(per BOE)
Oil and natural gas sales	$ 40.57	$	1.54	$	24.96
Royalties and production taxes	(9.57)		(0.24)		(5.51)
Cash operating expenses	(10.04)		(0.73)		(7.20)
Transportation costs	(1.85)		(0.64)		(2.87)
Netback before hedging	$ 19.11	$	(0.07)	$	9.38
Cash gains/(losses)	3.83		0.20		2.53
Netback after hedging	$ 22.94	$	0.13	$	11.91
Netback before hedging ($ millions)	$ 81.6	$	(1.8)	$	79.7
Netback after hedging ($ millions)	$ 98.0	$	3.4	$	101.3

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

Netbacks by Property Type	Six months ended June 30, 2016 Crude Oil		Natural Gas		Total
Average Daily Production	47,836 BOE/day		287,538 Mcfe/day		95,759 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)		(per Mcfe)		(per BOE)
Oil and natural gas sales	$ 33.82	$	1.70	$	21.99
Royalties and production taxes	(7.95)		(0.25)		(4.72)
Cash operating expenses	(10.06)		(0.88)		(7.67)
Transportation costs	(1.85)		(0.65)		(2.88)
Netback before hedging	$ 13.96	$	(0.08)	$	6.72
Cash gains/(losses)	6.08		0.16		3.51
Netback after hedging	$ 20.04	$	0.08	$	10.23
Netback before hedging ($ millions)	$ 121.5	$	(4.4)	$	117.0
Netback after hedging ($ millions)	$ 174.5	$	3.8	$	178.2

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

Crude oil and natural gas netbacks per BOE were higher for both the three and six months ended June 30, 2017 compared to the same periods in 2016 due to significantly higher oil and natural gas prices, improvements in the sales price differentials in North Dakota and Marcellus regions, along with reductions to our operating expenses, due to the sale of non-core Canadian natural gas assets. For the three and six month periods ended June 30, 2017, our crude oil properties accounted for 71% of our netback before hedging compared to 100% 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 June 30,		Six months ended June 30,	
($ millions)	2017	2016	2017	2016
Cash:				
G&A expense	$ 12.0	$ 14.6	$ 26.3	$ 33.0
Share-based compensation expense	—	0.8	0.1	1.5
Non-Cash:				
Share-based compensation expense	3.3	5.4	11.4	8.9
Equity swap loss/(gain)	—	(1.6)	1.0	(1.7)
Total G&A expenses	$ 15.3	$ 19.2	$ 38.8	$ 41.7

	Three months ended June 30,		Six months ended June 30,	
(Per BOE)	2017	2016	2017	2016
Cash:				
G&A expense	$ 1.53	$ 1.71	$ 1.69	$ 1.89
Share-based compensation expense	—	0.09	0.01	0.09
Non-Cash:				
Share-based compensation expense	0.42	0.63	0.74	0.51
Equity swap loss/(gain)	0.01	(0.18)	0.07	(0.10)
Total G&A expenses	$ 1.96	$ 2.25	$ 2.51	$ 2.39

For the three and six months ended June 30, 2017, cash G&A expenses were $12.0 million ($1.53/BOE) and $26.3 million ($1.69/BOE), respectively, compared to $14.6 million ($1.71/BOE) and $33.0 million ($1.89/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.

We recorded non-cash SBC of $3.3 million or $0.42/BOE in the second quarter of 2017 compared to $5.4 million or $0.63/BOE during the same period in 2016, due to a smaller employee base in 2017.

Based on our increased annual average production guidance and continued focus on costs, we are reducing our annual cash G&A guidance to $1.75/BOE from $1.85/BOE.

Interest Expense

For the three and six months ended June 30, 2017, we recorded total interest expense of $10.2 million and $20.4 million, respectively, compared to $10.0 million and $24.6 million for the same period in 2016. Interest expense was essentially flat when compared to the three months ended June 30, 2016, however decreased for the six months ended June 30, 2017 when compared to the same period in 2016. The decrease for the six month period ended June 30, 2017 was primarily due to the repurchase of US$267 million of senior notes during the first half of 2016.

At June 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 June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Realized loss/(gain)	$ 0.9	$ 0.3	$ 1.0	$ 2.0
Unrealized loss/(gain)	(13.1)	0.1	(17.0)	(56.0)
Total foreign exchange loss/(gain)	$ (12.2)	$ 0.4	$ (16.0)	$ (54.0)
USD/CDN average exchange rate	1.34	1.29	1.33	1.33
USD/CDN period end exchange rate	1.30	1.30	1.30	1.30

For the three and six months ended June 30, 2017, we recorded net foreign exchange gains of $12.2 million and $16.0 million, respectively, compared to a loss of $0.4 million and a gain of $54.0 million for the same periods in 2016. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies, while unrealized gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. Comparing June 30, 2017 to December 31, 2016, the Canadian dollar strengthened relative to the U.S. dollar resulting in unrealized gains of $17.0 million. See Note 12 to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Capital spending	$ 101.7	$ 48.1	$ 222.1	$ 91.4
Office capital	0.3	0.1	0.4	0.1
Sub-total	102.0	48.2	222.5	91.5
Property and land acquisitions	$ 4.7	$ 0.3	$ 7.2	$ 3.9
Property divestments	(59.8)	(92.7)	(58.9)	(280.5)
Sub-total	(55.1)	(92.4)	(51.7)	(276.6)
Total	$ 46.9	$ (44.2)	$ 170.8	$ (185.1)

Capital spending for the three and six months ended June 30, 2017, totaled $101.7 million and $222.1 million, respectively, compared to $48.1 million and $91.4 million for the same period 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 $70.7 million on our North Dakota crude oil properties, $17.5 million on our Marcellus natural gas assets and $9.9 million on our Canadian waterflood properties.

During the second quarter, we closed a portion of our previously announced Canadian asset divestments for proceeds of $59.6 million, after closing adjustments, with estimated 2017 production of approximately 5,600 BOE/day, and $46.9 million in asset retirement obligations. In comparison, during the same period of 2016 we completed the sale of properties in northwest Alberta for proceeds of $92.7 million, net of closing costs, with estimated 2016 production of 2,300 BOE/day and $12.7 million in asset retirement obligations.

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 during the second quarter of 2017. In comparison, we recorded a gain of $74.7 million on certain asset divestments during the second quarter 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 three and six month periods ended June 30, 2016, we recorded gains of $12.2 million and $19.3 million on the repurchase of US$95 million and US$267 million, respectively, in outstanding senior notes at a discount to par value.

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

($ millions, except per BOE amounts)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
DD&A expense	$ 64.8	$ 82.9	$ 125.4	$ 174.2
Per BOE	$ 8.26	$ 9.73	$ 8.09	$ 10.00

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three and six months ended June 30, 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 in the first half of 2017 compared to a decrease during the same period in 2016. There were no non-cash impairments recorded for the three and six months ended June 30, 2017, compared to $148.7 million and $194.9 million 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. Although the trailing twelve month average commodity prices are approximately in line with current levels, there is the potential for prices to decline, impacting the ceiling value and resulting 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 $110.7 million at June 30, 2017, compared to $181.7 million at December 31, 2016. For the three and six months ended June 30, 2017, asset retirement obligation settlements were $1.5 million and $4.1 million, respectively, compared to $0.8 million and $3.2 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 June 30, 2017	2016	Six months ended June 30, 2017	2016
Current tax expense/(recovery)	$ 2.0	$ (0.2)	$ 2.1	$ (0.4)
Deferred tax expenses/(recovery)	38.3	53.3	67.1	309.8
Total tax expense/(recovery)	$ 40.3	$ 53.1	$ 69.2	$ 309.4

For the three and six months ended June 30, 2017, we recorded total tax expense of $40.3 million and $69.2 million, respectively, compared to $53.1 million and $309.4 million for the same periods in 2016.

Current tax expense for the three and six months ended June 30, 2017 was $2.0 million and $2.1 million, respectively, compared to recoveries of $0.2 million and $0.4 million for the same periods in 2016. The increase in current tax expense is primarily due to higher income in the U.S.

Deferred tax expense was higher in both comparative periods due to a valuation allowance recorded in both Canada and the U.S. We assess the recoverability of our deferred income tax assets each period to the 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 $648.6 million at June 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 June 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 June 30, 2017 was $308.1 million, a decrease of 18% compared to $375.5 million at December 31, 2016. Total debt was comprised of $693.1 million of senior notes less $385.1 million in cash. Proceeds from the December, 2016 sale of our non-operated North Dakota properties were released from escrow on June 29, 2017 and are now being held as cash, without restriction. In June 2017, we made the first of five annual installments of US$22 million on the remaining principal of the US$110 million 2009 senior notes. At June 30, 2017, we were undrawn on our $800 million bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by adjusted funds flow, was 96% and 101% for the three and six months ended June 30, 2017, respectively, compared to 72% and 96% for the same periods in 2016.

Our working capital deficiency, excluding cash and current deferred financial assets and liabilities, increased to $104.5 million at June 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.

At June 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 June 30, 2017:

Covenant Description		June 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%	26%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0 x	20.8x

Definitions

"Senior debt" is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended June 30, 2017 was $200.6 million and $858.2 million, respectively.
"Total debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.
"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes

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

Dividends

($ millions, except per share amounts)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Dividends to shareholders	$ 7.3	$ 6.5	$ 14.5	$ 21.0
Per weighted average share (Basic)	$ 0.03	$ 0.03	$ 0.06	$ 0.10

During the three and six months ended June 30, 2017, we reported total dividends of $7.3 million or $0.03 per share and $14.5 million or $0.06 per share, respectively, compared to $6.5 million or $0.03 per share and $21.0 million or $0.10 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

	Six months ended June 30, 2017	Six months ended June 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)	241,710	212,420
Weighted average shares outstanding – diluted (thousands)	246,566	212,420

During the second quarter, no shares were issued pursuant to our LTI plans, resulting in no additional equity being recorded during the period (2016 – nil). For the six months ended June 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).

At August 10, 2017, we had 242,128,944 shares outstanding.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended June 30, 2017			Three months ended June 30, 2016		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes (1)						
Crude oil (bbls/day)	10,853	26,008	36,861	13,497	25,582	39,079
Natural gas liquids (bbls/day)	1,199	2,934	4,133	1,418	3,411	4,829
Natural gas (Mcf/day)	46,729	224,563	271,292	79,878	218,625	298,503
Total average daily production (BOE/day)	19,840	66,369	86,209	28,228	65,431	93,659
Pricing (2)						
Crude oil (per bbl)	$ 50.45	$ 57.83	$ 55.66	$ 43.27	$ 48.18	$ 46.48
Natural gas liquids (per bbl)	37.35	20.14	25.14	25.14	11.74	15.67
Natural gas (per Mcf)	3.59	3.46	3.48	1.41	1.52	1.49
Capital Expenditures						
Capital spending	$ 10.6	$ 91.1	$ 101.7	$ 7.2	$ 40.9	$ 48.1
Acquisitions	1.1	3.6	4.7	1.0	(0.7)	0.3
Divestments	(59.6)	(0.2)	(59.8)	(91.1)	(1.6)	(92.7)
Netback(3) Before Hedging						
Oil and natural gas sales	$ 69.2	$ 212.9	$ 282.1	$ 66.6	$ 146.1	$ 212.7
Royalties	(14.3)	(42.1)	(56.4)	(9.7)	(28.7)	(38.4)
Production taxes	(0.8)	(13.0)	(13.8)	(0.1)	(8.5)	(8.6)
Cash operating expenses	(19.4)	(26.8)	(46.2)	(31.4)	(30.0)	(61.4)
Transportation costs	(3.1)	(26.1)	(29.2)	(3.9)	(20.6)	(24.5)
Netback before hedging	$ 31.6	$ 104.9	$ 136.5	$ 21.5	$ 58.3	$ 79.8
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (31.9)	$ —	$ (31.9)	$ 21.9	$ —	$ 21.9
General and administrative expense (4)	7.9	7.4	15.3	14.7	4.5	19.2
Current income tax expense/(recovery)	—	2.0	2.0	(0.4)	0.2	(0.2)

	Six months ended June 30, 2017			Six months ended June 30, 2016		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes (1)						
Crude oil (bbls/day)	11,875	23,155	35,030	13,841	25,453	39,294
Natural gas liquids (bbls/day)	1,301	2,347	3,648	1,612	3,549	5,161
Natural gas (Mcf/day)	57,575	223,818	281,393	89,708	218,119	307,827
Total average daily production (BOE/day)	22,772	62,805	85,577	30,404	65,355	95,759
Pricing (2)						
Crude oil (per bbl)	$ 51.11	$ 59.32	$ 56.54	$ 34.70	$ 41.33	$ 39.00
Natural gas liquids (per bbl)	37.21	26.88	30.57	25.05	8.07	13.37
Natural gas (per Mcf)	3.62	3.54	3.56	1.74	1.59	1.64
Capital Expenditures						
Capital spending	$ 35.6	$ 186.5	$ 222.1	$ 26.3	$ 65.1	$ 91.4
Acquisitions	2.7	4.5	7.2	2.0	1.9	3.9
Divestments	(58.7)	(0.2)	(58.9)	(279.4)	(1.1)	(280.5)
Netback(3) Before Hedging						
Oil and natural gas sales	$ 156.3	$ 403.5	$ 559.8	$ 123.3	$ 259.9	$ 383.2
Royalties	(26.2)	(80.1)	(106.3)	(15.1)	(51.1)	(66.2)
Production taxes	(1.9)	(22.3)	(24.2)	(0.9)	(15.1)	(16.0)
Cash operating expenses	(45.9)	(50.5)	(96.4)	(74.9)	(58.8)	(133.7)
Transportation costs	(7.5)	(51.3)	(58.8)	(7.5)	(42.7)	(50.2)
Netback before hedging	$ 74.8	$ 199.3	$ 274.1	$ 24.9	$ 92.2	$ 117.1
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (89.5)	$ —	$ (89.5)	$ 8.4	$ —	$ 8.4
General and administrative expense (4)	25.7	13.1	38.8	33.1	8.6	41.7
Current income tax expense/(recovery)	—	2.1	2.1	(0.7)	0.3	(0.4)

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

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2017				
Second Quarter	$ 225.7	$ 129.3	$ 0.53	$ 0.52
First Quarter	227.8	76.3	0.32	0.31
Total 2017	$ 453.5	$ 205.6	$ 0.85	$ 0.83
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 slightly in the second quarter compared to the first quarter of 2017 due to lower realized commodity prices offset by higher oil and natural gas liquids production volumes. 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.

U.S. Filing Status

Pursuant to U.S. securities regulations, we are required to reassess our U.S. securities filing status annually at June 30. As at June 30, 2017, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

2017 UPDATED GUIDANCE

We are increasing our annual average production guidance range to 84,000 – 86,000 BOE/day from 81,000 – 85,000 BOE/day, and increasing the lower end of our crude oil and natural gas liquids volume range to 39,500 – 41,500 BOE/day from 38,500 – 41,500 BOE/day previously. We are reducing our cash costs by $0.65/BOE, with revised guidance targets for operating expenses of $6.40/BOE, cash G&A expenses of $1.75/BOE, and transportation costs of $3.90/BOE. We are also increasing our expected 2017 average Marcellus differential to US$0.75/Mcf below NYMEX from US$0.60/Mcf.

All other guidance targets remain unchanged and are summarized below. This guidance includes our previously announced divestments of certain non-core Canadian properties, but does not include any additional acquisitions or divestments.

Summary of 2017 Expectations	Target
Capital spending	$450 million
Average annual production	84,000 – 86,000 BOE/day (from 81,000 - 85,000 BOE/day)
Fourth quarter average production	86,000 – 91,000 BOE/day
Average annual crude oil and natural gas liquids production	39,500 – 41,500 bbls/day (from 38,500 – 41,500 bbls/day)
Fourth quarter average annual crude oil and natural gas liquids production	43,000 – 48,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	24%
Operating expenses	$6.40/BOE (from $6.85/BOE)
Transportation costs	$3.90/BOE (from $4.00/BOE)
Cash G&A expenses	$1.75/BOE (from $1.85/BOE)

2017 Differential/Basis Outlook(1)	
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(4.50)/bbl
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.75)/Mcf (from US$(0.60)/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 June 30,**		**Six months ended June 30,**	
($ millions)	**2017**	**2016**	**2017**	**2016**
Oil and natural gas sales	$ 282.1	$ 212.7	$ 559.8	$ 383.2
Less:				
Royalties	(56.4)	(38.4)	(106.3)	(66.2)
Production taxes	(13.8)	(8.6)	(24.2)	(16.0)
Cash operating expenses(1)	(46.2)	(61.4)	(96.4)	(133.7)
Transportation costs	(29.2)	(24.5)	(58.8)	(50.2)
Netback before hedging	$ 136.5	$ 79.8	$ 274.1	$ 117.1
Cash gains/(losses) on derivative instruments	2.2	21.6	8.8	61.2
Netback after hedging	$ 138.7	$ 101.4	$ 282.9	$ 178.3

(1) Total operating expenses adjusted to exclude non-cash gains on fixed price electricity swaps of $0.4 million and $0.3 million in the three and six months ended June 30, 2017, and $0.9 million and $0.6 million, respectively, in the three and six months ended June 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 June 30,**		**Six months ended June 30,**	
($ millions)	**2017**	**2016**	**2017**	**2016**
Cash flow from operating activities	$ 98.3	$ 61.9	$ 226.2	$ 131.6
Asset retirement obligation expenditures	1.5	0.7	4.1	3.2
Changes in non-cash operating working capital	14.4	13.4	3.8	(17.0)
Adjusted funds flow	$ 114.2	$ 76.0	$ 234.1	$ 117.8

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

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

Calculation of Adjusted Payout Ratio	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2017**	**2016**	**2017**	**2016**
Dividends	$ 7.3	$ 6.5	$ 14.5	$ 21.0
Capital and office expenditures	102.0	48.2	222.5	91.5
Sub-total	$ 109.3	$ 54.7	$ 237.0	$ 112.5
Adjusted funds flow	$ 114.2	$ 76.0	$ 234.1	$ 117.8
Adjusted payout ratio (%)	96%	72%	101%	96%

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

Reconciliation of Net Income to Adjusted EBITDA(1)

($ millions)		June 30, 2017
Net income/(loss)	$	945.2
Add:		
Interest		40.4
Current and deferred tax expense/(recovery)		(477.5)
DD&A and asset impairment		387.2
Other non-cash charges(2)		(14.2)
Sub-total	$	881.1
Adjustment for material acquisitions and divestments(3)		(22.9)
Adjusted EBITDA	$	858.2

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at June 30, 2017 include the six months ended June 30, 2017 and the third and fourth quarters 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 “total debt net of cash “senior debt to adjusted EBITDA”, “total debt to adjusted EBITDA”, “total debt to capitalization”, “maximum debt to consolidated present value of total proved reserves” and “adjusted EBITDA to interest” and are used to determine the Company’s compliance with financial covenants under its bank credit facility and outstanding senior notes. Calculation of such terms is described under the “Liquidity and Capital Resources” section of this MD&A.

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a - 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109 - Certification of Disclosure in Issuer’s Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at June 30, 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 April 1, 2017 and ended June 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, second half 2017, and 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; 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; 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 rest of the year: a WTI price of US$50.00/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.40/GJ and a USD/CDN exchange rate of 1.30. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued low commodity prices environment or further volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our AIF, our Annual MD&A and Form 40-F as at December 31, 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	June 30, 2017	December 31, 2016
Assets			
Current Assets			
Cash		$ 385,058	$ 1,257
Restricted cash		—	392,048
Accounts receivable	4	95,324	115,368
Deferred financial assets	15	31,424	—
Other current assets		8,804	6,721
		520,610	515,394
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	5	768,404	726,452
Other capital assets, net	5	10,102	11,978
Property, plant and equipment		778,506	738,430
Goodwill		644,942	651,663
Deferred financial assets	15	11,373	—
Deferred income tax asset	13	648,608	733,363
Total Assets		$ 2,604,039	$ 2,638,850
Liabilities			
Current liabilities			
Accounts payable	7	$ 177,688	$ 184,534
Dividends payable		2,421	2,405
Current portion of long-term debt	8	28,549	29,539
Deferred financial liabilities	15	3,718	28,615
		212,376	245,093
Deferred financial liabilities	15	—	12,266
Long-term debt	8	664,576	739,286
Asset retirement obligation	9	110,718	181,700
		775,294	933,252
Total Liabilities		987,670	1,178,345
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: June 30, 2017 – 242 million shares			
December 31, 2016 – 240 million shares	14	3,386,946	3,365,962
Paid-in capital		64,229	73,783
Accumulated deficit		(2,141,551)	(2,332,641)
Accumulated other comprehensive income		306,745	353,401
		1,616,369	1,460,505
Total Liabilities & Shareholders' Equity		$ 2,604,039	$ 2,638,850
Contingencies	16		

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 June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Revenues					
Oil and natural gas sales, net of royalties	10	$ 225,695	$ 174,330	$ 453,511	$ 316,991
Commodity derivative instruments gain/(loss)	15	31,948	(21,907)	89,510	(8,443)
		257,643	152,423	543,021	308,548
Expenses					
Operating		45,768	60,540	96,149	133,130
Transportation		29,205	24,495	58,833	50,213
Production taxes		13,803	8,541	24,167	15,977
General and administrative	11	15,340	19,244	38,833	41,697
Depletion, depreciation and accretion		64,779	82,892	125,359	174,235
Asset impairment	6	—	148,679	—	194,856
Interest		10,211	10,064	20,352	24,598
Foreign exchange (gain)/loss	12	(12,150)	383	(16,008)	(54,025)
Gain on divestment of assets	5	(78,400)	(74,700)	(78,400)	(219,800)
Gain on prepayment of senior notes	8	—	(12,152)	—	(19,270)
Other expense/(income)		(558)	(82)	(1,043)	(242)
		87,998	267,904	268,242	341,369
Income/(Loss) before taxes		169,645	(115,481)	274,779	(32,821)
Current income tax expense/(recovery)	13	2,040	(227)	2,114	(386)
Deferred income tax expense	13	38,303	53,300	67,070	309,785
Net Income/(Loss)		$ 129,302	$ (168,554)	$ 205,595	$ (342,220)
Other Comprehensive Income/(Loss)					
Change in cumulative translation adjustment		(36,354)	1,654	(46,656)	(64,714)
Other Comprehensive Income/(Loss)		(36,354)	1,654	(46,656)	(64,714)
Total Comprehensive Income/(Loss)		$ 92,948	$ (166,900)	$ 158,939	$ (406,934)
Net income/(Loss) per share					
Basic	14	$ 0.53	$ (0.77)	$ 0.85	$ (1.61)
Diluted	14	$ 0.52	$ (0.77)	$ 0.83	$ (1.61)

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	Six months ended June 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	11,430	8,820
Balance, end of period	$ 64,229	$ 55,589
Accumulated Deficit		
Balance, beginning of year	$ (2,332,641)	$ (2,694,618)
Net income/(loss)	205,595	(342,220)
Dividends	(14,505)	(21,011)
Balance, end of period	$ (2,141,551)	$ (3,057,849)
Accumulated Other Comprehensive Income/(Loss)		
Balance, beginning of year	$ 353,401	$ 402,672
Change in cumulative translation adjustment	(46,656)	(64,714)
Balance, end of period	$ 306,745	$ 337,958
Total Shareholders' Equity	$ 1,616,369	$ 701,660

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 June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Operating Activities					
Net income/(loss)		$ 129,302	$ (168,554)	$ 205,595	$ (342,220)
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		64,779	82,892	125,359	174,235
Asset impairment		—	148,679	—	194,856
Changes in fair value of derivative instruments	15	(30,031)	41,060	(79,960)	67,395
Deferred income tax expense	13	38,303	53,300	67,070	309,785
Foreign exchange (gain)/loss on debt and working capital	12	(13,064)	131	(16,975)	(56,027)
Share-based compensation	14	3,310	5,391	11,430	8,820
Gain on divestment of assets	5	(78,400)	(74,700)	(78,400)	(219,800)
Gain on prepayment of senior notes	8	—	(12,152)	—	(19,270)
Asset retirement obligation expenditures	9	(1,523)	(750)	(4,064)	(3,204)
Changes in non-cash operating working capital	17	(14,382)	(13,410)	(3,838)	17,064
Cash flow from/(used in) operating activities		98,294	61,887	226,217	131,634
Financing Activities					
Proceeds from the issuance of shares		—	220,410	—	220,410
Cash dividends		(7,264)	(6,547)	(14,505)	(21,011)
Increase/(decrease) in bank credit facility		(4,043)	(150,073)	(23,272)	(79,223)
Proceeds/(repayment) of senior notes	8	(29,084)	(109,371)	(29,084)	(335,400)
Changes in non-cash financing working capital		—	334	16	(3,791)
Cash flow from/(used in) financing activities		(40,391)	(45,247)	(66,845)	(219,015)
Investing Activities					
Capital and office expenditures		(102,022)	(48,206)	(222,515)	(91,498)
Property and land acquisitions		(4,713)	(343)	(7,249)	(3,897)
Property divestments	5	59,842	92,735	58,942	280,503
Decrease/(increase) in restricted cash		380,939	—	380,939	—
Changes in non-cash investing working capital		(10,071)	(11,909)	16,251	(54,035)
Cash flow from/(used in) investing activities		323,975	32,277	226,368	131,073
Effect of exchange rate changes on cash		(982)	(1,026)	(1,939)	(2,018)
Change in cash		380,896	47,891	383,801	41,674
Cash, beginning of period		4,162	1,281	1,257	7,498
Cash, end of period		$ 385,058	$ 49,172	$ 385,058	$ 49,172

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 August 10, 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 six months ended June 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 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 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. The Company is evaluating both the full retrospective and modified retrospective methods of adoption as it works through its analysis. Enerplus is currently reviewing the terms of its sales contracts with customers to determine the impact, if any, that the standard will have on the Consolidated Financial Statements. The Company currently expects that the standard will not have a material impact on the Consolidated Financial Statements other than enhanced disclosures.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842).* The ASU introduces a lessee accounting model that requires lessees to recognize a right-of-use asset and related lease liability on the balance sheet for those leases classified as finance and operating, with some exceptions. 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, and continues to assess the impact it will have on the Consolidated Financial Statements.

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 (Topic 350): Simplifying the Test for Goodwill Impairment*. This standard eliminates Step 2 of the goodwill impairment test, and requires a goodwill impairment charge for the amount that the goodwill carrying amount 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)	June 30, 2017	December 31, 2016
Accrued receivables	$ 67,934	$ 83,774
Accounts receivable – trade	29,463	33,305
Current income tax receivable	1,130	1,564
Allowance for doubtful accounts	(3,203)	(3,275)
Total accounts receivable, net of allowance for doubtful accounts	$ 95,324	$ 115,368

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

As of June 30, 2017 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 13,546,093	$ (12,777,689)	$ 768,404
Other capital assets	105,901	(95,799)	10,102
Total PP&E	$ 13,651,994	$ (12,873,488)	$ 778,506

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.

During the three and six months ended June 30, 2017, Enerplus recorded a gain on asset divestments of $78.4 million on the second quarter sale of certain Canadian assets for proceeds of $59.6 million, after closing adjustments (three and six months ended June 30, 2016 – gains of $74.7 million and $219.8 million, respectively, and proceeds of $92.7 million and $280.5 million, respectively).

6) ASSET IMPAIRMENT

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2017	2016	2017	2016
Oil and natural gas properties:				
Canada cost centre	$ —	$ 34,200	$ —	$ 34,200
U.S. cost centre	—	114,479	—	160,656
Impairment expense	$ —	$ 148,679	$ —	$ 194,856

With increases in the 12-month average trailing crude oil and natural gas prices, there was no impairment recorded for the six months ended June 30, 2017. The impairment for the three and six months ended June 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 June 30, 2016 through June 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
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
Q2 2016	43.12	1.32	53.16	2.25	2.14

7) ACCOUNTS PAYABLE

($ thousands)	June 30, 2017	December 31, 2016
Accrued payables	$ 106,324	$ 104,816
Accounts payable - trade	71,364	79,718
Total accounts payable	$ 177,688	$ 184,534

8) DEBT

($ thousands)	June 30, 2017	December 31, 2016
Current:		
Senior notes	$ 28,549	$ 29,539
	28,549	29,539
Long-term:		
Bank credit facility	$ —	$ 23,226
Senior notes	664,576	716,060
	664,576	739,286
Total debt	$ 693,125	$ 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	$ 136,258
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	25,954
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	386,715
June 18, 2009	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017	7.97%	US$225,000	US$88,000	114,198
					Total carrying value	$ 693,125
					Current portion	28,549
					Long-term portion	$ 664,576

During the three months ended June 30, 2017, Enerplus made a principal repayment of US$22 million on its 2009 senior notes. For the six months ended June 30, 2016, Enerplus repurchased US$267 million in outstanding senior notes at a discount, resulting in gains of $19.3 million.

9) ASSET RETIREMENT OBLIGATION

($ thousands)	Six months ended June 30, 2017	Year ended December 31, 2016
Balance, beginning of year	$ 181,700	$ 206,359
Change in estimates	751	5,496
Property acquisitions and development activity	610	3,003
Dispositions	(72,096)	(35,635)
Settlements	(4,064)	(8,390)
Accretion expense	3,817	10,867
Balance, end of period	$ 110,718	$ 181,700

Enerplus has estimated the present value of its asset retirement obligation to be $110.7 million at June 30, 2017 compared to $181.7 million at December 31, 2016 based on a total undiscounted liability of $312.0 million and $452.1 million, respectively. The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.82% (December 31, 2016 – 5.86%).

10) OIL AND NATURAL GAS SALES

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2017	2016	2017	2016
Oil and natural gas sales	$ 282,090	$ 212,741	$ 559,835	$ 383,164
Royalties(1)	(56,395)	(38,411)	(106,324)	(66,173)
Oil and natural gas sales, net of royalties	$ 225,695	$ 174,330	$ 453,511	$ 316,991

(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 June 30,		Six months ended June 30,	
($ thousands)	2017	2016	2017	2016
General and administrative expense	$ 11,981	$ 14,600	$ 26,252	$ 33,026
Share-based compensation expense(1)	3,359	4,644	12,581	8,671
General and administrative expense	$ 15,340	$ 19,244	$ 38,833	$ 41,697

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

12) FOREIGN EXCHANGE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2017	2016	2017	2016
Realized:				
Foreign exchange loss	$ 914	$ 252	$ 967	$ 2,002
Unrealized:				
Translation of U.S. dollar debt and working capital (gain)/loss	(13,064)	131	(16,975)	(56,027)
Foreign exchange (gain)/loss	$ (12,150)	$ 383	$ (16,008)	$ (54,025)

13) INCOME TAXES

($ thousands)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Current tax expense/(recovery)				
Canada	$ —	$ (366)	$ —	$ (669)
United States	2,040	139	2,114	283
Current tax expense/(recovery)	2,040	(227)	2,114	(386)
Deferred tax expense/(recovery)				
Canada	$ 25,563	$ 21,069	$ 39,182	$ 33,915
United States	12,740	32,231	27,888	275,870
Deferred tax expense/(recovery)	38,303	53,300	67,070	309,785
Income tax expense/(recovery)	$ 40,343	$ 53,073	$ 69,184	$ 309,399

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. As at June 30, 2017 Enerplus' total valuation allowance was $343.7 million (December 31, 2016 - $347.9 million).

14) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized unlimited number of common shares issued: (thousands)	Six months ended June 30, 2017 Shares	Amount	Year ended December 31, 2016 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 six months ended June 30, 2017 were $7.3 million and $14.5 million, respectively (2016 - $6.5 million and $21.0 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 June 30, 2017	2016	Six months ended June 30, 2017	2016
Cash:				
Long-term incentive plans expense	$ (15)	$ 773	$ 140	$ 1,506
Non-cash:				
Long-term incentive plans and stock option expense	3,310	5,391	11,430	8,820
Equity swap (gain)/loss	64	(1,520)	1,011	(1,655)
Share-based compensation expense	$ 3,359	$ 4,644	$ 12,581	$ 8,671

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

In 2014, the Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") plans were amended such that grants under the plans are settled through the issuance of treasury shares. The amendment was effective beginning with our grant in March of 2014 and any prior grants were settled in cash. The final cash-settled PSU and RSU grants were settled in December, 2015 and March, 2016, respectively. The Company's Director Share Units ("DSU") continue to be granted as cash-settled awards.

The following table summarizes the PSU, RSU and DSU activity for the six months ended June 30, 2017:

For the six months ended June 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	60	821	814	1,695
Vested	—	(528)	(1,118)	(1,646)
Forfeited	—	(36)	(237)	(273)
Balance, end of period	366	2,699	2,157	5,222

Cash-settled LTI Plans

For the three and six months ended June 30, 2017, the Company recorded cash share-based compensation expense of nil and $0.1 million, respectively (2016 - $0.8 million and $1.5 million, respectively). For the three and six months ended June 30, 2017, the Company made cash payments of nil and $0.1 million, respectively, related to its cash-settled plans (2016 – nil and $2.7 million, respectively).

As of June 30, 2017, a liability of $3.8 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 six months ended June 30, 2017, the Company recorded non-cash share-based compensation expense of $3.3 million and $11.4 million, respectively (2016 – $5.4 million and $8.8 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 June 30, 2017 ($ thousands, except for years)	PSU(1)	RSU	Total
Cumulative recognized share-based compensation expense	$ 20,541	$ 8,721	$ 29,262
Unrecognized share-based compensation expense	11,365	8,463	19,828
Fair value	$ 31,906	$ 17,184	$ 49,090
Weighted-average remaining contractual term (years)	1.7	1.5	

(1) Includes estimated performance multipliers.

ii) Stock Option Plan

The Company suspended the issuance of stock options in 2014. At June 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 period ended June 30, 2017:

Period ended June 30, 2017	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding, beginning of year	5,900	$ 18.29
Forfeited	(154)	18.39
Options outstanding, end of period	5,746	$ 18.29
Options exercisable, end of period	5,746	$ 18.29

At June 30, 2017, Enerplus had 5,745,664 options that were exercisable at a weighted average exercise price of $18.29 with a weighted average remaining contractual term of 2.1 years, giving an aggregate intrinsic value of nil (2016 – 3.0 years and nil). The intrinsic value of options exercised for both the three and six months ended June 30, 2017 was nil (2016 – nil and nil, respectively).

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

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

	Three months ended June 30,		Six months ended June 30,	
(thousands, except per share amounts)	2017	2016	2017	2016
Net income/(loss)	$ 129,302	$ (168,554)	$ 205,595	$ (342,220)
Weighted average shares outstanding – Basic	242,127	218,128	241,710	212,420
Dilutive impact of share-based compensation(1)	4,856	—	4,856	—
Weighted average shares outstanding – Diluted	246,983	218,128	246,566	212,420
Net income/(loss) per share				
Basic	$ 0.53	$ (0.77)	$ 0.85	$ (1.61)
Diluted(1)	$ 0.52	$ (0.77)	$ 0.83	$ (1.61)

(1) For the three and six months ended June 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 June 30, 2017 the carrying value of cash, accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value due to the short-term maturity of the instruments.

At June 30, 2017 senior notes had a carrying value of $693.1 million and a fair value of $709.3 million (December 31, 2016 - $746.0 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 six months ended June 30, 2017 and 2016:

	Three months ended June 30,		Six months ended June 30,		
Gain/(Loss) ($ thousands)	2017	2016	2017	2016	Income Statement Presentation
Electricity Swaps	$ 387	$ 885	$ 270	$ 577	Operating expense
Equity Swaps	(64)	1,520	(1,011)	1,655	G&A expense
Commodity Derivative Instruments:					
Oil	27,280	(27,144)	71,638	(58,420)	Commodity derivative instruments
Gas	2,428	(16,321)	9,063	(11,207)	
Total	$ 30,031	$ (41,060)	$ 79,960	$ (67,395)	

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

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2017	2016	2017	2016
Change in fair value gain/(loss)	$ 29,708	$ (43,465)	$ 80,701	$ (69,627)
Net realized cash gain/(loss)	2,240	21,558	8,809	61,184
Commodity derivative instruments gain/(loss)	$ 31,948	$ (21,907)	$ 89,510	$ (8,443)

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

	June 30, 2017			December 31, 2016	
	Assets		Liabilities	Liabilities	
($ thousands)	Current	Long-term	Current	Current	Long-term
Electricity Swaps	$ —	$ —	$ 371	$ 641	$ —
Equity Swaps	—	—	2,946	1,044	891
Commodity Derivative Instruments:					
Oil	31,424	11,373	—	17,466	11,375
Gas	—	—	401	9,464	—
Total	$ 31,424	$ 11,373	$ 3,718	$ 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 August 10, 2017:

Crude Oil Instruments:

Instrument Type(1)	bbls/day	US$/bbl
Jul 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 – Jun 30, 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)
Jul 1, 2018 – Dec 31, 2018		
WTI Swap	3,000	53.73
WTI Purchased Put	17,000	52.56
WTI Sold Call	17,000	61.29
WTI Sold Put	17,000	42.63
WCS Differential Swap	1,500	(14.75)
Jan 1, 2019 – Mar 31, 2019		
WTI Swap	3,000	53.73
WTI Purchased Put	1,000	56.00
WTI Sold Call	1,000	70.00
WTI Sold Put	1,000	45.00
Apr 1, 2019 – Dec 31, 2019		
WTI Purchased Put	4,000	54.69
WTI Sold Call	4,000	66.18
WTI Sold Put	4,000	43.75

(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
Jul 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

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

Electricity Instruments:

Instrument Type	MWh	CDN$/Mwh
Jul 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:		
Jul 1, 2017 – Oct 31, 2017 AECO-NYMEX Basis	35.0	(1.14)
Sales:		
Jul 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, and U.S. dollar denominated senior notes 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 June 30, 2017 Enerplus did not have any foreign exchange derivatives outstanding.

Interest Rate Risk:

As of June 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 June 30, 2017 approximately 62% of Enerplus' marketing receivables were with companies considered investment grade.

At June 30, 2017 approximately $5.5 million or 6% of Enerplus' total accounts receivable were aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. 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 June 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 June 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 June 30,		Six months ended June 30,	
($ thousands)	2017	2016	2017	2016
Accounts receivable	$ (3,617)	$ 288	$ 18,055	$ 29,640
Other current assets	1,770	(3,426)	(2,541)	(96)
Accounts payable	(12,535)	(10,272)	(19,352)	(12,480)
	$ (14,382)	$ (13,410)	$ (3,838)	$ 17,064

b) Other

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2017	2016	2017	2016
Income taxes paid/(received)	$ 1,875	$ (17,194)	$ 1,939	$ (19,118)
Interest paid	16,807	17,832	20,451	27,638

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

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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

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