NEWS RELEASE

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Enerplus Announces Fourth Quarter and Year-end 2016 Financial and Operating Results and 2016 Year-end Reserves

All financial information contained within this news release has been prepared in accordance with U.S. GAAP. This news release includes forward-looking statements and information within the meaning of applicable securities laws. Readers are advised to review the "Forward-Looking Information and Statements" at the conclusion of this news release. Readers are also referred to "Information Regarding Reserves, Resources and Operational Information", "Notice to U.S. Readers" and "Non-GAAP Measures" at the end of this news release for information regarding the presentation of the financial, reserves, contingent resources and operational information in this news release, as well as the use of certain financial measures that do not have standard meaning under U.S. GAAP. A copy of Enerplus' 2016 Financial Statements and MD&A is available on our website at www.enerplus.com, under our profile on SEDAR at www.sedar.com and on the EDGAR website at www.sec.gov. All amounts in this news release are stated in Canadian dollars unless otherwise specified.

Calgary, Alberta - Enerplus Corporation ("Enerplus" or the "Company") (TSX: ERF) (NYSE: ERF) today announced financial and operating results for the quarter and year ended December 31, 2016, along with year-end 2016 reserves.

President and CEO Ian C. Dundas stated, "Enerplus delivered another strong performance in 2016 underpinned by consistent operational execution, top quartile capital efficiencies, and a continued focus on improving the financial strength of the business. Once again in 2016 the Company met or exceeded all of its financial and operating targets, including significantly strengthening the balance sheet having reduced net debt by $841 million, or 69%, over the course of the year. With the Company's lower cost structure and improving differentials in the Bakken and Marcellus, we have seen a step change in the cash flow generating capability and financial sustainability of the business."

"As we increase activity at our Fort Berthold operations in 2017, we expect to deliver meaningful production growth and strong economic returns, setting the foundation for a 20% compound annual liquids production growth rate over the coming three-year period."

Financial and Operational Highlights

- Fourth quarter 2016 production averaged 88,960 BOE per day, bringing annual average 2016 production to 93,125 BOE per day, in line with guidance of 93,000 BOE per day. Fourth quarter 2016 crude oil and natural gas liquids production averaged 41,541 barrels per day, impacted by severe weather in North Dakota during the quarter. Annual average 2016 liquids production was 43,256 barrels per day, within the guidance range of 43,000 to 44,000 barrels per day.

- Enerplus realized strong value from its non-core divestments in 2016, selling 13,500 BOE per day (60% natural gas) of production for aggregate proceeds of $670.4 million.

- The Company reported fourth quarter 2016 net income of $840.3 million, or $3.43 per diluted share. Net income was impacted by a gain on the sale of the Company's non-operated North Dakota properties of $339.4 million, and a non-cash deferred tax recovery of $567.8 million primarily as a result of the reversal of a portion of the valuation allowance on the Company's deferred tax asset. For the year ended December 31, 2016, Enerplus reported net income of $397.4 million, or $1.72 per diluted share, compared with a net loss of $1,523.4 million, or $7.39 per share, for the comparable 2015 period.

- Enerplus generated fourth quarter 2016 adjusted funds flow of $107.7 million, an increase of 34% from the previous quarter as a result of stronger commodity prices in the fourth quarter. The Company generated full year 2016 adjusted funds flow of $305.6 million, down 38% from the comparable 2015 period due to lower average commodity prices and lower hedging gains in 2016.

- Enerplus delivered strong operating cost performance in 2016 reflecting efficiency improvements and the divestment of higher cost properties. Fourth quarter operating expenses were $7.15 per BOE, a reduction of 18% compared to the same period in 2015. Full year 2016 operating expenses were $7.27 per BOE, a reduction of 17% compared to 2015.

- Fourth quarter 2016 cash G&A expenses were $1.63 per BOE, a reduction of 7% compared to the same period in 2015. Full year 2016 cash G&A expenses were $1.75 per BOE, a reduction of 16% compared to 2015. Enerplus' lower G&A cost structure is, in part, a result of a reduction in staffing levels related to non-core asset divestments.

- Transportation expense in the fourth quarter of 2016 was $3.44 per BOE, up slightly from the previous quarter. Full year 2016 transportation expense was $3.14 per BOE, a 6% increase from the prior year period.

- Capital spending in the fourth quarter of 2016 was $57.5 million, with approximately 71% allocated to North Dakota. Full year 2016 capital spending totaled $209.1 million, slightly below annual 2016 guidance of $215.0 million.

- Enerplus significantly strengthened its balance sheet during 2016 having reduced its total debt, net of cash and restricted cash, by 69%, or $840.7 million, over the twelve-month period. Total debt, net of cash and restricted cash, at December 31, 2016 was $375.5 million, and was comprised of $23.2 million of bank indebtedness and $745.6 million of senior notes less $393.3 million in cash, including $392.0 million in restricted cash. The restricted cash balance reflects proceeds from the sale of the Company's non-operated North Dakota properties which were placed in escrow in order to facilitate possible future like-kind transactions in accordance with U.S. federal tax regulations. Net debt to adjusted funds flow at year-end was 1.2 times.

2016 Reserves Highlights

- Replaced 126% of 2016 production, adding 42.6 MMBOE (42% crude oil and natural gas liquids) of proved plus probable ("2P") reserves from development activities (including revisions).

- Material reserves growth was realized in Enerplus' North Dakota and Marcellus assets. The Company replaced 207% of 2016 North Dakota production, excluding production from Enerplus' non-operated North Dakota assets which were sold at the end of 2016, adding 17.5 MMBOE of 2P reserves (including revisions). The Company also replaced 175% of 2016 Marcellus production, adding 125.0 Bcf of 2P reserves (including revisions).

- Finding and development ("F&D") costs for proved developed producing ("PDP") reserves decreased by 60% to $4.77 per BOE for 2016, generating a PDP reserves recycle ratio of 2.0 times based on a 2016 operating netback (before hedging) of $9.66 per BOE. Enerplus' three-year average PDP reserves F&D cost was $10.37 per BOE.

- F&D costs for 2P reserves decreased by 43% to $4.82 per BOE for 2016, including future development costs ("FDC"), generating a 2P reserves recycle ratio of 2.0 times. Enerplus' three-year average 2P reserves F&D cost, including FDC, was $8.11 per BOE.

- Enerplus sold various non-core properties in 2016 representing 37.3 MMBOE of 2P reserves at a combined value of $20.38 per BOE. Total 2P reserves, net of divestments, were 382.5 MMBOE at year-end 2016, representing a 6% decrease from year-end 2015. Excluding acquisitions and divestments, 2P reserves increased by 2% in 2016.

- 2P reserves were comprised of 51% crude oil and natural gas liquids and 49% natural gas at year-end 2016.

- Total proved reserves account for 70% of 2P reserves. PDP reserves represent 71% of total proved reserves and 50% of 2P reserves.

Operational Overview

2016 PRODUCTION & CAPITAL SPENDING

	Q4 2016 Average Production	2016 Annual Average Production	2016 Capital Spending ($million)
Crude Oil & NGLs (bbls/day)			
Canada	13,577	14,497	$44.4
United States	27,964	28,759	$140.4
Total Crude Oil & NGLs (bbls/day)	**41,541**	**43,256**	**$184.8**
Natural Gas (Mcf/day)			
Canada	68,437	79,057	-
United States	216,078	220,157	$24.3
Total Natural Gas (Mcf/day)	**284,515**	**299,214**	**$24.3**
Company Total (BOE/day)	**88,960**	**93,125**	**$209.1**

2016 NET DRILLING ACTIVITY[(1)]

	Wells Drilled	Wells On-stream
Crude Oil		
Canada[(2)]	8.0	6.0
United States	16.0	16.1
Total Crude Oil	**24.0**	**22.1**
Natural Gas		
Canada	-	-
United States	1.3	5.2
Total Natural Gas	**1.3**	**5.2**
Company Total	**25.3**	**27.3**

(1) Table may not add due to rounding.
(2) Includes injector wells.

Asset Activity

WILLISTON BASIN

Williston Basin production averaged 31,981 BOE per day in the fourth quarter of 2016, a decrease of 3% from the prior quarter largely due to severe weather affecting operations at Fort Berthold in North Dakota at the end of the quarter. Production from North Dakota in the fourth quarter averaged 27,391 BOE per day, a decrease of 5% from the prior quarter. As previously announced, Enerplus completed the sale of approximately 5,000 BOE per day of non-operated North Dakota production at the end of the fourth quarter. Full year 2016 production from the Williston Basin averaged 32,888 BOE per day, approximately flat to 2015 average production.

Capital spending in North Dakota in the fourth quarter of 2016 was $41.1 million. At Fort Berthold, Enerplus drilled three net wells and brought 3.6 net wells on production during the fourth quarter. Enerplus completed three operated wells in the fourth quarter, which were part of a density test comprising two Middle Bakken wells spaced at 500 feet offset by one First Bench Three Forks well at 700 feet. The average initial 30-day production rate from the two Middle Bakken wells was 1,667 BOE per day with continued strong production over the initial 90-day period averaging over 1,200 BOE per day. The initial 30-day production rate of the First Bench Three Forks well was 1,530 BOE per day and the initial 90-day production rate was also over 1,200 BOE per day. These results further support Enerplus' revised development plan of approximately ten wells per drilling spacing unit.

In 2016, Enerplus drilled 13 net operated wells (16 gross) and brought 13 net operated wells (17 gross) on production. The average total operated well cost (drill, complete, and facilities) in 2016 for a 10,000 foot lateral was US$8.0 million. Including non-operated wells, total net wells drilled in 2016 were 16 and total net wells completed were 16. With the ramp-up in activity at Fort Berthold in 2017, Enerplus expects to drill approximately 26 net operated wells (34 gross) and bring 28 net operated wells (36 gross) on production under a two rig program. This is projected to drive 50% production growth in North Dakota from the beginning of 2017 through the fourth quarter.

Enerplus estimates that it has protected approximately 75% of its 2017 North Dakota capital program from cost escalation through service contracting. The Company is budgeting for an US$8.0 million total well cost in 2017 for a 10,000 foot lateral under its base completion design of 1,000 pounds of proppant per lateral foot.

Enerplus ended 2016 with approximately 11 net drilled uncompleted wells in North Dakota.

Enerplus' Bakken crude oil price realizations continued to improve in 2016 due to declining basin production and strong regional refinery demand. Enerplus' realized Bakken differential below WTI improved by 21% year over year, averaging US$7.46 per barrel in 2016 compared to US$9.44 per barrel in 2015. In the fourth quarter of 2016, Enerplus' Bakken differential averaged US$6.80 per barrel below WTI. With the expectation that the Dakota Access Pipeline will be completed and in service around mid-year 2017, increasing regional takeaway capacity, Enerplus is improving its forecast 2017 Bakken crude oil differential to US$4.50 per barrel below WTI, from its previous guidance of US$6.00 per barrel below WTI.

MARCELLUS

Marcellus production averaged 192 MMcf per day in the fourth quarter of 2016, a decrease of 6% from the prior quarter. Enerplus estimates that it had approximately 30 MMcf per day of production curtailed during October 2016 due to low natural gas prices resulting from high regional storage inventories combined with seasonal demand weakness. Regional Marcellus natural gas prices strengthened in November 2016 and production has been at or close to full capacity since that time.

There was minimal drilling activity in the Marcellus during 2016, with capital activity largely focused on bringing drilled uncompleted wells on production. During the latter part of the fourth quarter of 2016, in response to improving natural gas prices, a modest level of drilling activity recommenced with Enerplus participating in drilling approximately one net well with one net well brought on production. Capital spending in the fourth quarter was $4.2 million. In total, Enerplus participated in drilling one net well in 2016 and approximately five net wells that were brought on production. Full year 2016 production from the Marcellus averaged 195 MMcf per day, approximately 4% lower than 2015 average production.

Enerplus ended 2016 with approximately four net drilled uncompleted wells in the Marcellus.

Enerplus' realized Marcellus differential improved in 2016 to US$0.93 per Mcf below NYMEX, compared to US$1.37 per Mcf below NYMEX in 2015. Lower capital spending in the region combined with growing regional gas fired power demand and continued pipeline capacity additions have helped to alleviate some of the transportation constraints in the region. In the fourth quarter of 2016, despite weak pricing in October, Enerplus' realized Marcellus differential averaged US$0.88 per Mcf below NYMEX. The recent improvement in Marcellus natural gas prices is expected to drive a moderate return to drilling activity in 2017. Enerplus is forecasting 2017 drilling activity of approximately eight net wells and bringing six net wells on production, for total capital spending of $60 million. With the current strength in NYMEX natural gas prices and Enerplus' forecast average 2017 Marcellus differential of US$0.90 per Mcf, the Marcellus is expected to generate meaningful free cash flow in 2017.

CANADIAN WATERFLOODS

Canadian waterflood production averaged 15,748 BOE per day in the fourth quarter of 2016, an increase of 7% from the prior quarter largely due to the acquisition of the Ante Creek property, which closed mid-way through the fourth quarter. Full year 2016 production from the Canadian waterfloods averaged 16,137 BOE per day, a decrease of approximately 16% from 2015 reflecting the divestment of properties in the Peace River Arch area in June 2016 and lower capital spending in 2016.

Fourth quarter 2016 capital spending in the waterfloods was $10.2 million with full year 2016 capital spending of $44.4 million, a 60% reduction in spending year over year. 2016 capital spending was focused on the expansion and development of existing waterfloods, sustaining polymer injection at Medicine Hat Glauc 'C' and Giltedge, and maintenance activities. Enerplus is budgeting moderately higher spending in the waterflood portfolio in 2017 at $60 million. Capital activity in 2017 will be predominately focused on waterflood optimization and expansion at Cadogan and Southeast Saskatchewan, ongoing polymer injection at Medicine Hat Glauc 'C' and Giltedge, and ramping up water injection at Ante Creek where Enerplus plans to be injecting from eight wells by year-end.

Enerplus' high-margin, low decline Canadian waterflood portfolio is expected to continue to be a strong cash flow generator in 2017. At US$55 per barrel WTI, Enerplus is forecasting approximately $150 million in net operating income from its waterflood assets in 2017.

Risk Management

Enerplus continues to protect its capital plans through commodity hedging. Using swaps and collar structures, Enerplus has an average of 18,000 barrels per day of crude oil protected in 2017 (approximately 63% of forecast crude oil production net of royalties), 12,500 barrels per day of crude oil protected in 2018, and 4,000 barrels per day of crude oil protected in 2019.

Commodity Hedging Detail (As at February 23, 2017)

	WTI Crude Oil (US$/bbl)					NYMEX Natural Gas (US$/Mcf)
	Jan 1, 2017 – Jun 30, 2017	**Jul 1, 2017 – Dec 31, 2017**	**Jan 1, 2018 – Dec 31, 2018**	**Jan 1, 2019 – Mar 31, 2019**	**Apr 1, 2019 – Dec 31, 2019**	**Jan 1, 2017 – Dec 31, 2017**
Swaps						
Sold Swaps	$53.50	$53.50	$53.73	$53.73	-	-
Volume (bbls/d or Mcf/d)	2,000	2,000	3,000	3,000	-	-
Three-Way Collars						
Sold Puts	$38.94	$39.62	$43.13	$45.00	$43.75	$2.06
Volume (bbls/d or Mcf/d)	14,000	18,000	9,500	1,000	4,000	50,000
Purchased Puts	$50.29	$50.61	$54.00	$56.00	$54.69	$2.75
Volume (bbls/d or Mcf/d)	14,000	18,000	9,500	1,000	4,000	50,000
Sold Calls	$61.14	$60.33	$63.09	$70.00	$66.18	$3.41
Volume (bbls/d or Mcf/d)	14,000	18,000	9,500	1,000	4,000	50,000

2017 Guidance

Enerplus' previously announced 2017 guidance is provided below, including its updated Bakken crude oil differential assumption of US$4.50 per barrel below WTI (from US$6.00 per barrel below WTI previously).

Capital spending	$450 million
Average annual production	86,000 – 90,000 BOE per day
Q4 average production	92,000 – 97,000 BOE per day
Average annual crude oil and natural gas liquids production	40,000 – 43,000 bbls per day
Q4 average crude oil and natural gas liquids production	45,000 – 50,000 bbls per day
Average royalty and production tax rate	23%
Operating expense	$7.85 per BOE
Transportation expense	$3.90 per BOE
Cash G&A expense	$1.80 per BOE

2017 Differential/Basis Outlook(1)

U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(4.50) per bbl
Marcellus basis (compared to NYMEX natural gas)	US$(0.90) per Mcf

(1) Before field transportation costs.

Selected Financial and Operating Results

SELECTED FINANCIAL RESULTS	Three months ended December 31, 2016	Three months ended December 31, 2015	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015
Financial (000's)				
Adjusted Funds Flow[4]	$ 107,730	$ 102,674	$ 305,605	$ 493,101
Dividends to Shareholders	7,214	22,717	35,439	131,955
Net Income/(Loss)	840,325	(624,987)	397,416	(1,523,403)
Debt Outstanding net of cash and restricted cash	375,520	1,216,184	375,520	1,216,184
Capital Spending	57,462	89,490	209,135	493,403
Property and Land Acquisitions	118,452	8,794	126,126	9,552
Property Divestments	389,750	83,236	670,364	286,614
Debt to Adjusted Funds Flow Ratio[4]	1.2x	2.5x	1.2x	2.5x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ 3.49	$ (3.03)	$ 1.75	$ (7.39)
Net Income/(Loss) - Diluted	3.43	(3.03)	1.72	(7.39)
Weighted Average Number of Shares Outstanding (000's)	240,483	206,517	226,530	206,205
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 32.81	$ 23.81	$ 25.88	$ 27.07
Royalties and Production Taxes	(7.60)	(4.75)	(5.77)	(5.63)
Commodity Derivative Instruments	1.12	7.50	2.36	7.40
Cash Operating Expenses	(7.22)	(8.68)	(7.31)	(8.75)
Transportation Costs	(3.44)	(2.98)	(3.14)	(2.95)
General and Administrative Expenses	(1.63)	(1.75)	(1.75)	(2.09)
Cash Share-Based Compensation	(0.17)	0.16	(0.09)	(0.02)
Interest, Foreign Exchange and Other Expenses	(0.97)	(2.94)	(1.28)	(2.78)
Current Tax Recovery	0.26	0.07	0.07	0.43
Adjusted Funds Flow[4]	$ 13.16	$ 10.44	$ 8.97	$ 12.68

SELECTED OPERATING RESULTS	Three months ended December 31, 2016	Three months ended December 31, 2015	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015
Average Daily Production[2]				
Crude Oil (bbls/day)	37,128	41,135	38,353	41,639
Natural Gas Liquids (bbls/day)	4,413	5,092	4,903	4,763
Natural Gas (Mcf/day)	284,515	364,065	299,214	360,733
Total (BOE/day)	88,960	106,905	93,125	106,524
% Crude Oil and Natural Gas Liquids	47%	43%	46%	44%
Average Selling Price[2][3]				
Crude Oil (per bbl)	$ 53.91	$ 43.04	$ 44.84	$ 48.43
Natural Gas Liquids (per bbl)	21.31	16.61	15.29	18.06
Natural Gas (per Mcf)	2.89	1.89	2.06	2.15
Net Wells Drilled	5	2	25	46

(1) Non-cash amounts have been excluded.
(2) Based on Company interest production volumes. See "Basis of Presentation" section in the 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 MD&A.

Average Benchmark Pricing	Three months ended December 31, 2016	Three months ended December 31, 2015	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015
WTI crude oil (US$/bbl)	$ 49.29	$ 42.18	$ 43.32	$ 48.80
AECO natural gas – monthly index (CDN$/Mcf)	2.81	2.65	2.09	2.77
AECO natural gas – daily index (CDN$/Mcf)	3.09	2.47	2.16	2.69
NYMEX natural gas – last day (US$/Mcf)	2.98	2.27	2.46	2.66
US/CDN average exchange rate	1.33	1.34	1.32	1.28

Share Trading Summary For the twelve months ended December 31, 2016	CDN(1) – ERF (CDN$)	U.S.(2) – ERF (US$)
High	$ 13.55	$ 10.33
Low	$ 2.68	$ 1.84
Close	$ 12.74	$ 9.48

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

2016 Dividends per Share	CDN$	US$(1)
First Quarter Total	$ 0.09	$ 0.07
Second Quarter Total	$ 0.03	$ 0.02
Third Quarter Total	$ 0.03	$ 0.02
Fourth Quarter Total	$ 0.03	$ 0.02
Total Year to Date	$ 0.18	$ 0.13

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

INDEPENDENT RESERVES EVALUATION

All of the Company's reserves, including its U.S. reserves, have been evaluated in accordance with NI 51-101. Independent reserves evaluations have been conducted on properties comprising approximately 86% of the net present value (discounted at 10%, before tax, using January 1, 2017 forecast prices and costs) of the Company's total 2P reserves.

McDaniel, an independent petroleum consulting firm based in Calgary, Alberta, has evaluated properties which comprise approximately 48% of the net present value (discounted at 10%, before tax, using McDaniel's January 1, 2017 forecast prices and costs) of the Company's 2P reserves located in Canada and all of the Company's reserves associated with the Company's properties located in North Dakota and Montana. The Company has evaluated the remaining 52% of the net present value of its Canadian properties using similar evaluation parameters, including the same forecast price and inflation rate assumptions utilized by McDaniel. McDaniel has reviewed the Company's internal evaluation of these properties. NSAI, independent petroleum consultants based in Dallas, Texas, has evaluated all of the Company's reserves associated with the Company's properties in Pennsylvania. For consistency in the Company's reserves reporting, NSAI used McDaniel's January 1, 2017 forecast prices and inflation rates to prepare its report.

The following information sets out Enerplus' gross and net crude oil, NGLs and natural gas reserves volumes and the estimated net present values of future net revenues associated with such reserves as at December 31, 2016 using forecast price and cost cases, together with certain information, estimates and assumptions associated with such reserves estimates. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit associated with a property. It should be noted that tables may not add due to rounding.

Reserves Summary

Reserves Summary	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Gross								
Proved producing	11,306	26,388	45,402	83,096	8,242	89,205	509,215	191,073
Proved developed non-producing	15	-	420	435	17	4,839	989	1,423
Proved undeveloped	300	3,845	31,744	35,889	3,566	1,726	216,411	75,811
Total proved	11,621	30,232	77,566	119,419	11,825	95,769	726,614	268,308
Total probable	2,645	8,721	45,432	56,798	6,273	30,521	276,169	114,186
Proved plus Probable	**14,265**	**38,953**	**122,998**	**176,216**	**18,098**	**126,290**	**1,002,783**	**382,493**
Net								
Proved producing	9,677	21,857	36,740	68,274	6,675	87,416	408,473	157,597
Proved developed non-producing	14	-	351	365	12	3,966	827	1,177
Proved undeveloped	277	3,119	25,300	28,696	2,841	1,336	173,076	60,606
Total proved	9,968	24,976	62,391	97,335	9,528	92,717	582,375	219,379
Total probable	2,246	7,057	36,561	45,864	5,057	29,140	221,281	92,658
Proved plus Probable	**12,214**	**32,033**	**98,952**	**143,199**	**14,585**	**121,857**	**803,657**	**312,036**

Reserves Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a gross basis, from December 31, 2015 to December 31, 2016.

For the fourth consecutive year, the Company realized positive proved plus probable developed producing ("P+PDP") technical revisions at Fort Berthold and the Marcellus as a result of continued well outperformance. At Fort Berthold, the negative 2P technical revision is a function of the SEC five-year rule on converting proved undeveloped locations ("PUDs"). As Enerplus' program scheduling changes over time, PUDs that were originally scheduled to be drilled and completed within a certain period may not fit the current development plan timing and would therefore need to be removed from the Company's bookings. At year end 2016 Enerplus replaced 48 of these PUDs that in aggregate had a lower working interest, leading to the negative 2P technical revision.

The majority of the negative technical revision in the Probable reserves table below under the Shale Gas category, reflects the conversion of Marcellus Probable reserves into Proven reserves.

Proved Reserves - Gross Volumes (Forecast Prices)

	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2015	13,871	31,705	86,202	131,778	10,704	183,564	625,081	277,255
Acquisitions	1,765	-	-	1,765	24	14,162	-	4,149
Dispositions	(2,885)	-	(6,034)	(8,919)	(1,522)	(90,343)	(7,110)	(26,683)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	100	-	5,429	5,529	589	-	36,268	12,163
Economic factors	(606)	(533)	-	(1,139)	(173)	(4,731)	(30,053)	(7,110)
Technical revisions	1,123	2,088	1,182	4,393	3,925	20,012	183,193	42,187
Production	(1,746)	(3,027)	(9,214)	(13,987)	(1,722)	(26,894)	(80,763)	(33,653)
Proved Reserves at Dec. 31, 2016	**11,621**	**30,232**	**77,566**	**119,419**	**11,825**	**95,769**	**726,614**	**268,307**

Probable Reserves - Gross Volumes (Forecast Prices)

	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2015	3,367	9,804	45,051	58,222	4,993	53,802	338,288	128,563
Acquisitions	373	-	-	373	1	3,227	-	911
Dispositions	(845)	-	(3,680)	(4,525)	(622)	(29,438)	(3,566)	(10,648)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	45	-	13,810	13,855	1,540	-	27,948	20,053
Economic factors	534	(193)	-	341	(69)	(396)	1,998	540
Technical revisions	(829)	(890)	(9,749)	(11,468)	430	3,325	(88,499)	(25,234)
Production	-	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2016	**2,645**	**8,721**	**45,432**	**56,798**	**6,273**	**30,521**	**276,169**	**114,186**

Proved Plus Probable Reserves - Gross Volumes (Forecast Prices)

	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2015	17,238	41,509	131,253	190,000	15,697	237,366	963,368	405,818
Acquisitions	2,137	-	-	2,137	25	17,389	-	5,060
Dispositions	(3,730)	-	(9,713)	(13,443)	(2,145)	(119,781)	(10,676)	(37,331)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	145	-	19,239	19,384	2,129	-	64,216	32,216
Economic factors	(72)	(726)	-	(798)	(242)	(5,127)	(28,056)	(6,570)
Technical revisions	294	1,198	(8,566)	(7,074)	4,356	23,337	94,694	16,953
Production	(1,746)	(3,027)	(9,214)	(13,987)	(1,722)	(26,894)	(80,763)	(33,653)
Proved Plus Probable Reserves at Dec. 31, 2016	**14,265**	**38,953**	**122,998**	**176,216**	**18,098**	**126,290**	**1,002,783**	**382,493**

Future Development Costs

Changes in forecast FDC occur annually as a result of development activities, acquisition and divestment activities and capital cost estimates that reflect the evaluators' best estimate of the capital required to bring the proved and proved plus probable reserves on production. The aggregate of the exploration and development costs incurred in the most recent year and the change during the year in estimated future development costs generally reflect the total finding and development costs related to reserves additions for that year.

The following is a summary of the independent reserves evaluators' estimated FDC required to bring the total proved and proved plus probable reserves on production:

Future Development Costs	**Proved Reserves**	**Proved Plus Probable Reserves**
($ millions)		
2017	377	397
2018	393	478
2019	97	401
2020	24	298
2021	11	15
Remainder	42	40
Total FDC Undiscounted	944	1,629
Total FDC Discounted at 10%	829	1,357

F&D AND FD&A COSTS – *including future development costs*

($ millions except for per BOE amounts)	**2016**	**2015**	**2014**	**3 Year**
Proved Plus Probable Reserves				
Finding & Development Costs				
Capital Expenditures	$209.1	$493.4	$811.0	$1,513.6
Net change in Future Development Costs	$(4.0)	$(142.2)	$(71.3)	$(217.5)
Gross Reserves additions (MMBOE)	42.6	41.6	75.5	159.7
F&D costs ($/BOE)	**$4.82**	**$8.44**	**$9.80**	**$8.11**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$(335.1)	$216.2	$625.9	$507.0
Net change in Future Development Costs	$(94.5)	$(212.5)	$(59.2)	$(366.3)
Gross Reserves additions (MMBOE)	10.3	14.9	65.8	91.0
FD&A costs ($/BOE)	**$(41.60)**	**$0.25**	**$8.62**	**$1.55**
Proved Reserves				
Finding & Development Costs				
Capital Expenditures	$209.1	$493.4	$811.0	$1,513.6
Net change in Future Development Costs	$(124.4)	$210.0	$13.8	$99.4
Gross Reserves additions (MMBOE)	47.2	50.7	69.1	167.0
F&D costs ($/BOE)	**$1.79**	**$13.88**	**$11.94**	**$9.66**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$(335.1)	$216.2	$625.9	$507.0
Net change in Future Development Costs	$(202.1)	$139.7	$4.9	$(57.5)
Gross Reserves additions (MMBOE)	24.7	31.1	60.9	116.7
FD&A costs ($/BOE)	**$(21.74)**	**$11.44**	**$10.36**	**$3.85**
Proved Developed Producing Reserves				
Finding & Development Costs				
Capital Expenditures	$209.1	$493.4	$811.0	$1,513.6
Gross Reserves additions (MMBOE)	43.9	41.5	60.7	146.0
F&D costs ($/BOE)	**$4.77**	**$11.90**	**$13.37**	**$10.37**

Forecast Price Assumptions

The forecast price and cost case assumes no legislative or regulatory amendments, and includes the effects of inflation. The estimated future net revenue to be derived from the production of the reserves is based on the following price forecasts supplied by McDaniel as of January 1, 2017, (and utilized by NSAI and by the Company in its internal evaluations for consistency in the Corporation's reserves reporting), and the following inflation and exchange rate assumptions.

McDaniel January 2017 Forecast Price Assumptions

	WTI Crude Oil[1] US$/bbl	Light Crude Oil[2] Edmonton CDN$/bbl	Alberta Heavy Crude Oil[3] CDN$/bbl	U.S. Henry Hub Gas Price US$/MMBtu	Natural Gas Alberta Spot @ AECO CDN$/MMBtu	Exchange Rate US$/CDN$	Inflation Rate %/year
2017	55.00	69.80	46.50	3.40	3.40	0.750	0.0
2018	58.70	72.70	50.50	3.20	3.15	0.775	2.0
2019	62.40	75.50	54.00	3.35	3.30	0.800	2.0
2020	69.00	81.10	58.00	3.65	3.60	0.825	2.0
2021	75.80	86.60	61.90	4.00	3.90	0.850	2.0
2022	77.30	88.30	63.10	4.05	3.95	0.850	2.0
2023	78.80	90.00	64.40	4.15	4.10	0.850	2.0
2024	80.40	91.80	65.60	4.25	4.25	0.850	2.0
2025	82.00	93.70	67.00	4.30	4.30	0.850	2.0
2026	83.70	95.60	68.40	4.40	4.40	0.850	2.0
2027	85.30	97.40	69.60	4.50	4.50	0.850	2.0
2028	87.00	99.40	71.10	4.60	4.60	0.850	2.0
2029	88.80	101.40	72.50	4.65	4.65	0.850	2.0
2030	90.60	103.50	74.00	4.75	4.75	0.850	2.0
2031	92.40	105.50	75.40	4.85	4.85	0.850	2.0
Thereafter	[4]	[4]	[4]	[4]	[4]	0.850	[4]

(1) West Texas Intermediate at Cushing, Oklahoma 40 degree API / 0.5% Sulphur.
(2) Edmonton Light Sweet 40 degree API, 0.3% Sulphur.
(3) Heavy Crude Oil 12 degree API at Hardisty, Alberta (after deducting blending costs to reach pipeline quality).
(4) Escalation is approximately 2% per year thereafter.

Net Present Value of Future Production Revenue

The following table provides an estimate of the net present value of Enerplus' future production revenue after deduction of royalties, estimated future capital and operating expenditures, before income taxes. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves.

Net Present Value of Future Production Revenue – Forecast Prices and Costs *(before tax)*

Reserves at December 31, 2016, ($ Millions, discounted at)	**0%**	**5%**	**10%**	**15%**
Proved developed producing	4,021	2,767	2,117	1,730
Proved developed non-producing	20	11	7	6
Proved undeveloped	1,257	700	420	255
Total Proved	**5,297**	**3,479**	**2,544**	**1,991**
Probable	3,065	1,432	820	524
Total Proved Plus Probable Reserves (before tax)	**8,362**	**4,911**	**3,364**	**2,515**

Contingent Resources

The following table provides a breakdown of the economic, unrisked best estimate contingent resources associated with a portion of Enerplus' Fort Berthold, Marcellus, and Canadian waterflood assets as at December 31, 2016. These contingent resources are economic using McDaniel's January 1, 2017 forecast commodity prices, use established technologies and are all classified in the "development pending" maturity sub-class. There is uncertainty that it will be commercially viable to produce any portion of the resources.

The evaluations of contingent resources associated with a portion of Enerplus' waterflood properties and leases at Fort Berthold were conducted by Enerplus and audited by McDaniel. NSAI evaluated 100% of Enerplus' Marcellus shale gas assets in the U.S., including the estimate of contingent resources.

Please see Enerplus' Annual Information Form ("AIF") – Appendix A for additional disclosures related to Enerplus' contingent resources as at December 31, 2016. The AIF is available at www.enerplus.com as well as on the Company's SEDAR profile at www.sedar.com.

Development Pending Contingent Resources	**Unrisked "Best Estimate" Contingent Resources**		**Contingent Resources Net Drilling Locations**
Canada			
Waterfloods – IOR/EOR on a portion of waterfloods	34.4	MMBOE	54.3
Total Canada	**34.4**	**MMBOE**	**54.3**
United States Properties			
Fort Berthold – Bakken/Three Forks Tight Oil wells	119.8	MMBOE	215.3
Marcellus - Shale gas	837.0	Bcf	96.7
Total United States	**259.3**	**MMBOE**	**312.0**
Total Company	**293.7**	**MMBOE**	**366.3**

LIVE CONFERENCE CALL

Enerplus plans to hold a conference call hosted by Ian C. Dundas, President and CEO, today, February 24, 2017 at 9:00 a.m. MT (11:00 a.m. ET) to discuss these results. Details of the conference call are as follows:

Date:	Friday, February 24, 2017
Time:	9:00 am MT/11:00 am ET
Dial-In:	647-427-7450 1-888-231-8191 (toll free)
Audiocast:	http://event.on24.com/r.htm?e=1347471&s=1&k=96151D7131406EA88FD59E83EC73A3A5

To ensure timely participation in the conference call, callers are encouraged to dial in 15 minutes prior to the start time to register for the event. A telephone replay will be available for 30 days following the conference call and can be accessed at the following numbers:

Dial-In:	416-849-0833 1-855-859-2056 (toll free)
Passcode:	51750852

Electronic copies of our 2016 year-end MD&A and Financial Statements, along with other public information including investor presentations, are available on our website at www.enerplus.com. For further information, please contact Investor Relations at 1-800-319-6462 or email investorrelations@enerplus.com.

Follow @EnerplusCorp on Twitter at https://twitter.com/EnerplusCorp.

INFORMATION REGARDING RESERVES, RESOURCES AND OPERATIONAL INFORMATION

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), "MBOE" (one thousand barrels of oil equivalent), and "MMBOE" (one million barrels of oil equivalent). Enerplus has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOE, MBOE and MMBOE 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 and Reserves 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 IFRS and 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 Enerplus' 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. Unless otherwise specified, all reserves volumes in this news release (and all information derived therefrom) are based on "gross reserves" using forecast prices and costs. "Gross reserves" (as defined in NI 51-101), being Enerplus' working interest before deduction of any royalties. Enerplus' oil and gas reserves statement for the year ended December 31, 2016, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, is contained within our Annual Information Form for the year ended December 31, 2016 ("**our AIF**") which is available on our website at www.enerplus.com and under our SEDAR profile at www.sedar.com. Additionally, our AIF forms part of our Form 40-F that is filed with the U.S. Securities and Exchange Commission and is available on EDGAR at www.sec.gov. Readers are also urged to review the Management's Discussion & Analysis and financial statements filed on SEDAR and as part of our Form 40-F on EDGAR concurrently with this news release for more complete disclosure on our operations.*

Contingent Resources Estimates

*This news release contains estimates of "contingent resources". "Contingent resources" are not, and should not be confused with, oil and gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as ultimate recovery rates, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. All of our contingent resources estimates are economic using established technologies and based on McDaniel's January 1, 2017 forecast prices. Enerplus expects to develop these contingent resources in the coming years however it is too early in their development for these resources to be classified as reserves at this time. There is uncertainty that Enerplus will produce any portion of the volumes currently classified as "contingent resources". "Development pending contingent resources" refer to a "contingent resources" project maturity sub-class for a particular project where resolution of the final conditions for development are being actively pursued (there is a high chance of development) and the project is expected to be developed in a reasonable timeframe. The "contingent resources" estimates contained herein are presented as the "best estimate" of the quantity that will actually be recovered, effective as of December 31, 2016. A "best estimate" of contingent resources means that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.*

For additional information regarding the primary contingencies which currently prevent the classification of Enerplus' disclosed "contingent resources" associated with Enerplus' Marcellus shale gas properties, Enerplus' Fort Berthold properties, Enerplus' Wilrich natural gas properties and a portion of Enerplus' Canadian crude oil properties as reserves and the positive and negative factors relevant to the "contingent resources" estimates, see Appendix A to Enerplus' AIF, a copy of which is available under Enerplus' SEDAR profile at www.sedar.com, and Enerplus' Form 40-F, a copy of which is available under Enerplus' EDGAR profile at www.sec.gov.

F&D and FD&A Costs

F&D costs presented in this news release are calculated (i) in the case of F&D costs for proved reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves in the year, and (ii) in the case of F&D costs for proved plus probable reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding and development costs related to its reserves additions for that year.

FD&A costs presented in this news release are calculated (i) in the case of F&D costs for proved developed producing reserves, by dividing the sum of the exploration and development costs incurred in the year, by the additions to proved developed producing reserves in the year, (ii) in the case of FD&A costs for proved reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves including net acquisitions in the year, and (iii) in the case of FD&A costs for proved plus probable reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves including net acquisitions in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding, development and acquisition costs related to its reserves additions for that year.

NOTICE TO U.S. READERS

*The oil and natural gas reserves information contained in this news release has generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. Reserves categories such as "proved reserves" and "probable reserves" may be defined differently under Canadian requirements than the definitions contained in the United States Securities and Exchange Commission (the "**SEC**") rules. In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross (or, as noted above with respect to production information, "company interest") volumes, which are volumes prior to deduction of royalty and similar payments. The practice in the United States is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments. Canadian disclosure requirements require that forecasted commodity prices be used for reserves evaluations, while the SEC mandates the use of an average of first day of the month price for the 12 months prior to the end of the reporting period. Additionally, the SEC prohibits disclosure of oil and gas resources in SEC filings, whereas Canadian issuers may disclose oil and gas resources. Resources are different than, and should not be construed as reserves. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, contingent resources, see "Contingent Resources Estimates" above.*

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release certain forward-looking information and forward-looking statements within the meaning of applicable securities laws ("forward-looking information"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this news release contains forward-looking information pertaining to the following: expected 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, timing of related production, and ultimate well recoveries; oil and natural gas prices and differentials and our commodity risk management programs 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 and non-cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2017, 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; and expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes.

The forward-looking information contained in this news release reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and 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 2017 guidance contained in this news release is based on the following: a WTI price of US$55.00/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.75/GJ and a USD/CDN exchange rate of 1.35. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this 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: continued low commodity prices environment or further decline of commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in Enerplus' MD&A and in our other public filings).

The purpose of disclosure of net operating income from our Canadian waterflood assets is to assist readers in understanding our expected and targeted financial results, and this information may not be appropriate for other purposes. The forward-looking information contained in this press release speaks only as of the date of this press release, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws

NON-GAAP MEASURES

In this news release, Enerplus uses the terms "adjusted funds flow", "net debt to adjusted funds flow", and "netback" 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" is calculated as total debt net of cash, including restricted cash, divided by adjusted funds flow.

Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "adjusted funds flow", "net debt to adjusted funds flow", and "netback" 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' 2016 MD&A.

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation