NEWS RELEASE

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FOR IMMEDIATE RELEASE

Enerplus Announces Strong Third Quarter 2015 Results, A Reduction in the Monthly Dividend & 2016 Guidance

All financial information contained within this news release has been prepared in accordance with U.S. GAAP, except as noted under "Non-GAAP Measures". 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. A full copy of our Third Quarter 2015 Financial Statements and MD&A are 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.

Calgary, Alberta - Enerplus Corporation ("Enerplus" or the "Company") (TSX & NYSE: ERF) announces the results from operations for the third quarter of 2015, a reduction in its monthly dividend and 2016 guidance.

"Enerplus delivered another quarter of strong operational performance. With the continued improvement in our capital efficiencies and the lowering of our cost structure, we are increasing our 2015 production guidance, while reducing our guidance for capital spending, operating and G&A costs," stated Ian C. Dundas, President & CEO. "*As we look ahead into 2016, our focus is on sustainability. Our 2016 capital budget is down 30% from 2015, and we expect to operate near or within funds flow. To further enhance the Company's financial strength and sustainability in an extended low commodity price environment, we are reducing our monthly dividend to $0.03 per share from $0.05 per share, effective with our December 2015 dividend payment. While the dividend remains an important part of our strategy, its reduction reflects the need to rebalance the dividend level in the context of lower commodity prices."*

KEY TAKEAWAYS:

- Production was up 3% quarter over quarter averaging 110,794 BOE per day primarily driven by growth in North Dakota oil production, which increased over 20% from the second quarter of 2015 as a result of continued strong well performance and higher activity levels in the second and third quarters.

- Natural gas production was approximately 365 MMcf per day, slightly lower than the second quarter. Continued outperformance in the Marcellus was offset by a decrease in Canadian deep gas production as a result of scheduled turnarounds at major facilities. Overall, crude oil and natural gas liquids production increased to approximately 50,000 barrels per day during the quarter, up 8% over the previous quarter. Looking forward, we expect fourth quarter oil production to be lower than the third quarter as a result of both reduced on-stream activity in North Dakota and divestments.

- Subsequent to the quarter, we entered into an agreement to sell a portion of our non-operated North Dakota properties for proceeds of $80 million. This accretive divestment allows us to increase our focus on our operated North Dakota acreage where we can better align our financial and operational objectives. The divestment includes less than 2% of our overall North Dakota acreage. Estimated 2016 production from the existing wells within these properties is 1,000 BOE per day. The transaction is expected to close in the fourth quarter of 2015. We also divested of some minor non-core Canadian oil properties during the quarter, with associated production of 150 BOE per day, for proceeds of approximately $12 million.

- As a result of the strong production performance year to date, we are increasing our 2015 annual average production guidance to 106,000 BOE per day (from 100,000 – 104,000 BOE per day), with approximately 46,000 barrels per day of crude oil and natural gas liquids (from 44,000 – 46,000 barrels per day). This increased guidance assumes our non-operated North Dakota divestment closes in the fourth quarter of 2015.

- To enhance the Company's financial strength and sustainability in an extended low commodity price environment, the Board of Directors of Enerplus has approved a reduction in the monthly dividend to $0.03 per share from $0.05 per share, effective with the December 2015 dividend payment.

- Funds flow was $121 million in the third quarter, down approximately 25% from the previous quarter, primarily due to the decline in crude oil prices in the period.

- Capital spending was $89 million in the third quarter, down from $148 million in the second quarter. Capital was focused on our crude oil projects, with over 90% of spending directed to North Dakota and our Canadian waterflood assets. Due to continued cost improvement, strong operational performance, and the deferral of spending into 2016 we have reduced our annual 2015 capital spending to $510 million (from $540 million).

- Operating costs during the quarter were $8.87 per BOE, below our annual guidance of $9.25 per BOE. As expected, we saw an increase in operating costs from the second quarter as a result of seasonal turnaround activity. Third quarter cash G&A costs were $2.24 per BOE, in line with our annual guidance, despite one-time severance charges related to staff reductions that were incurred in the quarter. With the continued improvement in our cost structures and increased production guidance, we are decreasing our 2015 annual operating cost guidance to $9.00 per BOE and our cash G&A expense guidance to $2.20 per BOE.

- We incurred a non-cash asset impairment charge in the quarter of $321 million (before tax). Under U.S. GAAP we are required to use twelve month trailing average prices to determine impairment, and consequently the impairment reflects the low commodity prices in the fourth quarter of 2014 and the first three quarters of 2015.

- We ended the third quarter with a debt to funds flow ratio of 2.0 times and senior debt to EBITDA ratio of 1.8 times. Subsequent to the quarter, we paid the final installment of US$10.8 million on our maturing US$54 million senior notes. We have no additional scheduled debt repayments until June of 2017.

- At September 30, 2015 we were approximately 11% drawn on our covenant based $1.0 billion bank credit facility. Subsequent to the quarter, we completed a one year extension of our bank credit facility with our lending syndicate, which now matures in October 2018. After confirming with our syndicate banks that we could have maintained the facility at its current level, we chose to decrease the facility limit to $800 million as part of our ongoing cost savings initiatives. This decision balances the need for sufficient liquidity for the execution of our business plan against the associated costs of retaining a largely undrawn bank facility. We expect to realize savings of approximately $1 million as a result of the decreased facility size. At the end of 2015, we expect to be approximately 10% drawn on the resized facility.

Asset Activity

Production from North Dakota in the quarter was up over 20% from the previous quarter, averaging 32,600 BOE per day. We drilled 3.8 net wells in Fort Berthold with 6.5 net wells brought on-stream during the quarter for a total capital investment of $58 million. The growth in production is a result of continued strong well performance and an increase in on-stream activity during the second and third quarters. Our operated well completions activity was focused in the southeast area of our Fort Berthold acreage and included wells in both the Bakken and Three Forks formations. The wells were completed using a modified high volume completion design, and produced at an average initial 30 day production rate (IP30) of over 1,600 BOE per day, outperforming expectations. Well costs continue to trend down, with average well costs in the quarter, including facilities costs, of just under US$10 million. We continue to run a one-rig drilling program and, having deferred some completion activity into 2016, expect to have an inventory of approximately 10 drilled uncompleted wells at the end of 2015.

We continue to see reduced activity levels in the Marcellus. During the third quarter, our capital spending in the Marcellus was $3 million with 0.7 net wells drilled and 0.5 net wells brought on-stream. Despite the low capital investment, strong well performance led to a 5% production increase, to 210 MMcf per day, over the previous quarter.

In Canada, following the commercial success of the polymer pilot project at our Medicine Hat Glauc ‘C’ waterflood asset, we have sanctioned the installation of a second skid for our next polymer project. Construction of the project was completed in October on budget and on schedule. Polymer injection commenced in late October.

Production and Capital Spending

Crude Oil & NGLs (bbls/day)	Three months ended September 30, 2015		Nine months ended September 30, 2015	
	Average Production Volumes	Capital Spending ($ millions)	Average Production Volumes	Capital Spending ($ millions)
Canada	16,209	23.9	17,702	91.9
United States	33,740	58.6	28,759	252.9
Total Crude Oil & NGLs (bbls/day)	**49,949**	**82.5**	**46,461**	**344.8**
Natural Gas (Mcf/day)				
Canada	131,644	3.1	137,270	30.6
United States	233,427	3.3	222,341	28.5
Total Natural Gas (Mcf/day)	**365,071**	**6.4**	**359,611**	**59.1**
Company Total (BOE/day)	**110,794**	**88.9**	**106,396**	**403.9**

Net Drilling Activity*** – for the three months ended September 30, 2015

Crude Oil	Wells Drilled	Wells Pending Completion/ Tie-in *	Wells On-stream**	Dry & Abandoned Wells
Canada	3.0	2.0	2.0	-
United States	3.8	3.8	6.5	-
Total Crude Oil	**6.8**	**5.8**	**8.5**	**-**
Natural Gas				
Canada	0.6	-	2.3	-
United States	0.7	0.7	0.5	-
Total Natural Gas	**1.3**	**0.7**	**2.8**	**-**
Company Total	**8.0**	**6.4**	**11.3**	**-**

*Wells drilled during the quarter pending potential completion/tie-in or abandonment as at June 30, 2015.
**Total wells brought on-stream during the quarter regardless of when they were drilled.
***Table may not add due to rounding.

Crude Oil & Natural Gas Pricing

The West Texas Intermediate (WTI) benchmark price for crude oil fell by 20% versus the previous quarter to average US$46.43 per barrel during the third quarter. Although our U.S. Bakken crude oil differentials narrowed in the third quarter, the weakness in WTI prices resulted in a 17% reduction in the selling price for our crude oil compared to the previous quarter.

Natural gas prices at AECO and NYMEX were slightly stronger during the third quarter, both averaging 5% higher than the previous quarter. However, strong production levels and significant maintenance activities on the two major pipelines running through Northeast Pennsylvania contributed to the continued weakness in regional Marcellus pricing during the quarter, offsetting the strength in AECO and NYMEX on our realized natural gas price.

Marcellus basis differentials to NYMEX averaged US$1.64 per Mcf in the quarter. Basis differentials have improved recently in the region, with spot price differentials in the Marcellus trading between US$1.00 per Mcf to US$1.50 per Mcf below NYMEX, due to lower NYMEX prices and the recent tie-in of new regional export pipeline capacity.

Our commodity price hedge position is largely unchanged from the previous quarter. For the fourth quarter of 2015, we have an average of 14,500 barrels per day of crude oil (approximately 45% of our expected crude oil production, net of royalties) hedged at an average floor price of US$79.47 per barrel through a combination of swaps and three-way collar structures. In 2016 we have an average of 11,000 barrels per day of crude oil (approximately 34% of our expected crude oil production, net of royalties) hedged at an average floor price of US$64.35 per barrel through a combination of swaps and three-way collar structures.

Under our gas hedging program, for the fourth quarter of 2015 we are swapped on an average of 101,739 Mcf per day against NYMEX (approximately 36% of our forecasted natural gas production, net of royalties) at an average price of US$3.97 per Mcf. In 2016 we have 25,000 Mcf per day (approximately 9% of our forecasted natural gas production, net of royalties) hedged through three-way collars with an average floor price of US$3.00 per Mcf.

2015 Revised Guidance

We have increased our annual production guidance, reduced our capital spending guidance and decreased our operating cost and G&A expense guidance. All other guidance remains unchanged. This increased guidance assumes the divestment of a portion of our non-operated North Dakota property closes in the fourth quarter of 2015.

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

2016 Outlook

Our 2016 budget is focused on sustainability. Based on our continued operational success and improving capital efficiencies, we expect 2016 production to be relatively flat to 2015, despite our announced divestments, with capital spending levels significantly below those of 2015.

We have based our 2016 budget on commodity prices of US$50 per barrel WTI and US$3.00 per Mcf NYMEX. Under these assumptions, and including the proceeds of our fourth quarter divestment, we expect our capital expenditures and dividend payments to be fully funded.

Our 2016 capital budget is $350 million (down approximately 30% from 2015), with production of 100,000 – 105,000 BOE per day, including crude oil and natural gas liquids of 44,000 – 47,000 barrels per day. Our expected capital allocation will be heavily weighted to our crude oil properties at approximately 90% due to the stronger associated netback. We are maintaining flexibility to adjust capital spending based on commodity prices.

Operating costs are expected to average $9.20 per BOE in 2016, a slight increase from 2015, primarily due to the impact of a weak Canadian dollar on our U.S. dollar denominated operating costs. Our cash G&A guidance is $1.90 per BOE, down $0.30 per BOE from 2015 guidance as a result of staffing reductions in 2015 and continued cost savings initiatives.

2016 Guidance

Our 2016 guidance is based on the following assumptions: US$50 per barrel WTI, NYMEX natural gas of US$3.00 per Mcf, AECO natural gas at $2.85 per GJ, and US/CDN exchange of 1.33.

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

2016 Capital Allocation	$ million
U.S. Oil	$240
Canadian Oil	$70
Canadian Natural Gas (Deep Basin)	$20
U.S. Natural Gas (Marcellus)	$20

2016 Differential/Basis Outlook*	
U.S. Bakken (compared to WTI crude oil)	US$(8.00) per barrel
Marcellus Basis (compared to NYMEX natural gas)	US$(1.25) per Mcf

*Before field transportation costs

SELECTED FINANCIAL RESULTS

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Financial (000's)				
Funds Flow[4]	$ 120,845	$ 212,779	$ 390,427	$ 646,502
Cash and Stock Dividends	30,944	55,438	109,238	165,587
Net Income/(Loss)	(292,666)	67,430	(898,416)	147,424
Debt Outstanding – net of cash	1,226,552	1,091,110	1,226,552	1,091,110
Capital Spending	88,923	207,838	403,913	630,027
Property and Land Acquisitions	2,005	3,986	758	17,186
Property Divestments	11,865	68,931	203,378	185,631
Debt to Funds Flow Ratio[4]	2.0x	1.3x	2.0x	1.3x
Financial per Weighted Average Shares Outstanding				
Funds Flow	$ 0.58	$ 1.04	$ 1.89	$ 3.17
Net Income/(Loss) (Basic)	(1.42)	0.33	(4.36)	0.72
Weighted Average Number of Shares Outstanding (000's)	206,243	205,164	206,100	204,174
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 27.04	$ 47.67	$ 28.17	$ 52.13
Royalties and Production Taxes	(6.01)	(10.36)	(5.93)	(11.31)
Commodity Derivative Instruments	5.31	(0.26)	7.36	(1.52)
Cash Operating Expenses	(8.69)	(9.29)	(8.77)	(9.14)
Transportation Costs	(3.03)	(2.92)	(2.94)	(2.61)
General and Administrative	(2.24)	(1.97)	(2.21)	(2.08)
Cash Share-Based Compensation	0.35	0.54	(0.08)	(0.44)
Interest, Foreign Exchange and Other Expenses	(2.47)	(1.18)	(2.72)	(1.48)
Taxes	1.59	-	0.56	(0.40)
Funds Flow	$ 11.85	$ 22.23	$ 13.44	$ 23.15

SELECTED OPERATING RESULTS

	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Average Daily Production(2)				
Crude Oil (bbls/day)	44,888	40,332	41,809	39,328
Natural Gas Liquids (bbls/day)	5,061	3,869	4,652	3,591
Natural Gas (Mcf/day)	365,071	359,007	359,611	356,288
Total (BOE/day)	110,794	104,035	106,396	102,300
% Crude Oil and Natural Gas Liquids	45%	42%	44%	42%
Average Selling Price (2)(3)				
Crude Oil (per bbl)	$ 48.22	$ 88.28	$ 50.21	$ 92.55
Natural Gas Liquids (per bbl)	13.51	46.76	18.60	54.79
Natural Gas (per Mcf)	2.08	3.36	2.24	4.18
Net Wells Drilled	8	19	44	63

(1) Non-cash amounts have been excluded.

(2) Based on Company interest production volumes. See “Basis of Presentation” section in the following MD&A.

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

(4) These non-GAAP measures may not be directly comparable to similar measures presented by other entities. See “Non-GAAP Measures” section in the following MD&A.

Average Benchmark Pricing	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
WTI Crude Oil (US$/bbl)	$ 46.43	$ 97.17	$ 51.00	$ 99.61
AECO – monthly index (CDN$/Mcf)	2.80	4.22	2.80	4.55
AECO – daily index (CDN$/Mcf)	2.90	4.02	2.77	4.81
NYMEX – last day (US$/Mcf)	2.77	4.06	2.80	4.55
US/CDN exchange rate	1.31	1.09	1.26	1.09

Share Trading Summary For the three months ended September 30, 2015	CDN* ERF (CDN$)	U.S.** - ERF (US$)
High	$ 10.93	$ 8.80
Low	$ 6.04	$ 4.54
Close	$ 6.50	$ 4.86

* TSX and other Canadian trading data combined.

** NYSE and other U.S. trading data combined.

2015 Dividends per Share Payment Month	CDN$	US$(1)
First Quarter Total	$ 0.27	$ 0.22
Second Quarter Total	$ 0.15	$ 0.12
July	$ 0.05	$ 0.04
August	0.05	0.04
September	0.05	0.04
Third Quarter Total	$ 0.15	$ 0.12
Total Year-to-Date	$ 0.57	$ 0.46

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

Outlook

We delivered another quarter of consistent operational execution and disciplined capital spending which is underpinning the strength of our business. Our assets are performing well and our costs continue to decline. Our financial flexibility remains strong and we will continue to focus on improving efficiencies and sustainability as we move into 2016.

Importantly, despite the continued low commodity price environment, we remain committed to ensuring safe, responsible and sustainable operations across our business.

Q3 2015 Conference Call Details

A conference call hosted by Ian C. Dundas, President and CEO will be held at 9:00AM MT (11:00AM ET) today to discuss these results. Details of the conference call are as follows:

Date: Friday, November 6, 2015
Time: 9:00 AM MT (11:00 AM ET)
Dial-In: 647-427-7450
888-231-8191 (toll free)
Audiocast: http://event.on24.com/r.htm?e=1059283&s=1&k=4299D0FDEE63F7CD60E3097A62168840

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: 51232651

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 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 our Canadian peer companies, the summary results contained within this news release presents our 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 2015 and 2016 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity and foreign exchange risk management programs in 2015, 2016 and in the future; expectations regarding our realized oil and natural gas prices; anticipated cash and non-cash G&A, share based compensation and financing expenses; operating and transportation costs; capital spending levels in 2015 and 2016, anticipated drilling and completions program, and expected impact on our production level; potential future asset impairments; future debt and working capital levels and debt to funds flow ratio; our future acquisitions and dispositions, including timing thereof and expected proceeds therefrom; expectations regarding our measures to preserve our financial strength, including effectiveness thereof and amounts of anticipated savings therefrom; and the amount of future cash dividends that we may pay to our shareholders.

The forward-looking information contained in this 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 2015 revised guidance is based on the *following assumptions: September 30, 2015 forward market WTI price of $49.68/bbl, NYMEX gas price of $2.75/Mcf, AECO gas price of $2.66/GJ and US/CDN exchange rate of 1.28. Our 2016 preliminary guidance is based on WTI price of US$50/bbl, NYMEX gas price of US$3.00/Mcf, an AECO gas price of $2.85/GJ and US/CDN exchange rate of 1.33. 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 future decline, 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; our inability to comply with covenants under our 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 our AIF and Form 40-F at December 31, 2014).

NON-GAAP MEASURES

In this news release, we use the terms "funds flow" and "debt to funds flow ratio" as measures to analyze operating performance, leverage and liquidity. "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. "Debt to funds flow ratio" is calculated as total debt net of cash, divided by a trailing 12 months of funds flow. In addition, "senior debt to EBITDA" is used to determine Enerplus' compliance with financial covenants under its bank credit facility and outstanding senior notes. Calculation of these terms is described in our Third Quarter 2015 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 "funds flow" and "debt to funds flow" are useful supplemental measures as they provide an indication of the results generated by Enerplus' principal business activities. However, these measures, and "senior debt to EBITDA" 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 our Third Quarter 2015 MD&A.

Electronic copies of our Third Quarter 2015 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.

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Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation