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NEWS RELEASE

November 10, 2011

Enerplus Announces Results for the Third Quarter of 2011

Nov 10, 2011

All financial figures are unaudited and in Canadian dollars (CDN$) unless noted otherwise. All financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") including comparative figures pertaining to Enerplus' 2010 results. A reconciliation of comparative figures is provided in the notes to the Unaudited Interim Consolidated Financial Statements for the period ended September 30, 2011.

This news release includes forward-looking statements and information within the meaning of applicable securities laws. Readers are advised to review "Forward-Looking Information and Statements" at the conclusion of this news release. Readers are also referred to "Notice to U.S. Readers" and "Non-GAAP Measures" at the end of this news release for information regarding the presentation of the financial and operational information in this news release. A full copy of our 2011 Third Quarter Financial Statements and MD&A have been filed 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, Nov. 10, 2011 /CNW/ - Enerplus Corporation ("Enerplus") (TSX: ERF) (NYSE: ERF) is pleased to announce operating and financial results for the three months ended September 30, 2011. Highlights for the quarter include:

Production

- Daily production volumes averaged 73,245 BOE/day during the quarter which was approximately 3% lower than expected. Production volumes reflected the strategic sale of a portion of our Marcellus acreage which occurred at the end of June and delays primarily in the Fort Berthold region where our operations continued to be impacted by wet weather and service availability in a very busy basin.

- Year-to-date, we've brought 48 net wells on stream, just over half of the wells we planned to bring on-stream in 2011. During the fourth quarter, we expect to bring an additional 41 net wells on stream, approximately 90% of which are oil wells. As a result of this activity, we expect to achieve our exit production target of 81,000 - 84,000 BOE/day. With the slower than expected build in production through the first nine months of the year, we expect our full year production will average close to 76,000 BOE/day in 2011.

- Our drilling activities to date have been very encouraging, particularly in a number of core areas for us. Our first Three Forks test well at Fort Berthold, North Dakota has come on stream with a 30 day initial production rate of approximately 830 bbls/day and our first operated Marcellus well has tested significantly above expectations with a 24 hour peak test rate of 8.3 MMcf/day. We've also experienced positive results in the Ratcliffe and the Viking in Saskatchewan and recently completed a Bluesky delineation well at Ansell which tested at 4.2 MMcf/day. Overall, our drilling program is delivering at or above our expectations, just slightly behind the anticipated timeline.

Financial

- Our operations generated $123 million of funds flow ($0.68/share) during the quarter, net of current taxes of $32 million related to our Marcellus disposition and adjustments to prior year tax estimates. Excluding these taxes, our funds flow would have been approximately $155 million ($0.86/share).

- We invested approximately $200 million on drilling and related activities during the quarter, drilling approximately 35 net wells and bringing 12 net wells on-stream. Approximately 80% of our wells were oil wells and 34 of the 35 wells drilled were horizontal wells. Over 85% of our spending was directed to our Bakken, waterflood and Marcellus resource plays.

- Monthly dividends were maintained at $0.18 per share throughout the quarter representing a payout ratio of 79%. When combining dividend payments with our capital investment activities, we spent approximately 245% of our funds flow, utilizing our balance sheet to help fund these activities.

- We remain in a very solid financial position with only $265 million drawn on our $1 billion credit facility and a debt to funds flow ratio of 1.3x at the end of the quarter.

- Operating costs averaged $10.92/BOE during the quarter higher than expected as a result of lower production volumes and non-recurring charges for well servicing, repairs and maintenance resulting from wet weather in the spring and early summer. This included a $2.5 million charge to clean-up a landslide at our Tommy Lakes property. In the Fort Berthold area our fluid handling charges have been increasing due to restricted access to disposal wells and higher trucking costs as a result of truck shortages and road bans. We expect our operating costs to moderate in the remainder of the year as the majority of incremental costs related to the wet weather have been incurred. Based upon costs experienced to date, we are increasing our 2011 operating cost guidance from $9.20/BOE to $9.60/BOE.

- We currently have over 50% of our expected oil production in 2012 hedged at approximately $95/bbl and have started to add hedge positions for our 2013 oil production as well. Our gas production remains unhedged at this time as the benefit of locking in prices in a weak forward market remains limited.

New Growth Acquisitions

- We continue to add to our portfolio of undeveloped land in both Canada and the U.S. to build a solid inventory of future growth opportunities. Since the second quarter, we've added another 38,000 acres of land targeting the liquids-rich natural gas Duvernay play in the Willesden Green area and now hold approximately 100 sections of undeveloped land in the Duvernay. We expect to drill our first test well in 2012.

- We also acquired additional acreage in our emerging oil play portfolio and now hold approximately 25,000 acres in these prospects in Canada along with 75,000 net acres in the Bakken/Three Forks play in Fort Berthold, North Dakota.

- Our other significant land positions include over 110,000 net acres in the Marcellus (60% operated), over 33,000 net acres in the Montney, and over 67,000 net acres in the Stacked Mannville region of Alberta.

- Year-to-date, we've invested just over $100 million adding new growth positions in Canada. Our strategic land position now includes over 380,000 net acres in some of the most prospective oil and gas plays in North America that will support reserves, production and cash flow growth in the coming years.

SELECTED FINANCIAL RESULTS	Three months ended September 30,		Nine months ended September 30,	
	2011	2010[1]	**2011**	2010[1]
Financial (000's)				
Funds Flow [2]	**$123,262**	$193,328	**$416,927**	$566,363
Dividends to Shareholders	**97,416**	96,111	**291,179**	287,732
Net Income/(Loss)	**111,321**	(136,261)	**408,852**	(243,781)
Debt Outstanding - net of cash	**734,300**	680,264	**734,300**	680,264
Capital Spending	**201,266**	129,945	**520,875**	312,501
Property and Land Acquisitions	**67,313**	139,678	**209,946**	489,425
Divestments	**7,320**	150,747	**638,108**	333,523
Financial per Weighted Average Shares Outstanding				
Funds Flow [2]	**$0.68**	$1.10	**$2.32**	$3.23
Dividends	**0.54**	0.55	**1.62**	1.64
Net Income/(Loss)	**0.62**	(0.77)	**2.28**	(1.39)
Weighted Average Number of Shares Outstanding	**180,266**	176,075	**179,566**	175,430
Debt to Trailing 12 Month Funds Flow[5]	**1.3x**	1.2x	**1.3x**	1.2x

Selected Financial Results per BOE[3]				
Oil & Gas Sales[4]	**$46.44**	$40.08	**$48.34**	$42.96
Royalties	**(8.33)**	(7.29)	**(8.67)**	(7.74)
Commodity Derivative Instruments	**(0.66)**	2.76	**(1.09)**	1.84
Operating Costs	**(10.90)**	(10.08)	**(9.87)**	(10.05)
General and Administrative	**(2.45)**	(2.65)	**(2.96)**	(2.53)
Interest and Other Expenses	**(1.01)**	(1.88)	**(1.55)**	(1.28)
Taxes	**(4.80)**	4.42	**(3.75)**	1.45
Funds Flow[2]	**$18.29**	$25.36	**$20.45**	$24.65

SELECTED OPERATING RESULTS	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
Average Daily Production				
Natural gas (Mcf/day)	**243,675**	285,292	**250,244**	293,543
Crude oil (bbls/day)	**29,337**	31,639	**29,665**	31,393
NGLs (bbls/day)	**3,295**	3,681	**3,323**	3,842
Total (BOE/day)	**73,245**	82,869	**74,695**	84,159
% Natural gas	**55%**	57%	**56%**	58%
Average Selling Price[4]				
Natural gas (per Mcf)	**$ 3.73**	$3.67	**$3.83**	$4.19
Crude oil (per bbl)	**77.57**	66.97	**82.01**	69.80
NGLs (per bbl)	**64.98**	46.69	**63.89**	50.61
US/CDN exchange rate	**1.02**	0.96	**1.02**	0.97
Net Wells drilled	**35**	25	**75**	184

(1) 2010 comparative amounts have been restated and are presented in accordance with International Financial Reporting Standards ("IFRS") and represent the results of Enerplus Resources Fund which converted into Enerplus Corporation on January 1, 2011.

(2) See "Non-GAAP Measures" in the Management's Discussion and Analysis.

(3) Non-cash amounts have been excluded.

(4) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

(5) The 12 month trailing funds flow for September 30, 2010, includes funds flow for October through December 2009 which was prepared following previous Canadian GAAP.

SHARE TRADING SUMMARY	CDN* - ERF	U.S.** - ERF
For the three months ended September 30, 2011	(CDN$)	(US$)
High	$30.75	$31.99
Low	$25.13	$24.41
Close	$25.87	$24.54

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

2011 CASH DIVIDENDS PER SHARE	CDN$	US$
First Quarter Total	**$0.54**	**$0.55**
Second Quarter Total	**$0.54**	**$0.55**
July	$0.18	$0.19
August	0.18	0.18
September	0.18	0.18
Third Quarter Total	**$0.54**	**$0.55**
Total Year-to-Date	**$1.62**	**$1.65**

PRODUCTION & CAPITAL SPENDING	Three months ended September 30, 2011		Nine months ended September 30, 2011	
Play Type	Average Production Volumes	Capital Spending ($ millions)	Average Production Volumes	Capital Spending ($ millions)
Bakken/Tight Oil (BOE/day)	13,511	90	13,284	222
Crude Oil Waterfloods Oil (BOE/day)	13,462	33	13,404	79
Conventional Oil (BOE/day)	5,738	6	6,057	13
Total Oil (BOE/day)	32,711	129	32,745	314
Marcellus Shale Gas (Mcfe/day)	15,025	50	19,365	140
Other Natural Gas (Mcfe/day)	228,177	22	232,337	67
Total Gas (Mcfe/day)	243,202	72	251,702	207
Company Total	73,245	201	74,695	521

NET DRILLING ACTIVITY - for the three months ended September 30, 2011

Play Type	Horizontal Wells Drilled	Vertical Wells Drilled	Total Wells Drilled	Wells Pending Completion/ Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Bakken/Tight Oil	12.3	1.0	13.3	10.8	6.9	-
Crude Oil Waterfloods	14.1	-	14.1	12.1	2.4	-
Conventional Oil	0.6	-	0.6	0.3	0.7	-
Total Oil	**27.0**	**1.0**	**28.0**	**23.2**	**10.0**	**-**
Marcellus Shale Gas	4.5	-	4.5	4.3	1.1	-
Other Natural Gas	2.8	0.1	2.9	2.3	0.6	-
Total Gas	**7.3**	**0.1**	**7.4**	**6.6**	**1.7**	**-**
Company Total	**34.3**	**1.1**	**35.4**	**29.8**	**11.7**	**-**

*Wells drilled during the quarter pending potential completion/tie-in or abandonment
**Total wells brought on stream during the quarter regardless of when they were drilled

OPERATIONAL REVIEW

Bakken/Tight Oil

Our Bakken/tight oil production increased during the third quarter by approximately 900 BOE/day to average 13,511 BOE/day. The increase in production is attributable to our successful drilling activities in our U.S. Bakken properties in Montana and North Dakota. However, as a result of flooding earlier in the year in North Dakota, major state highway repair work continued into the third quarter and slowed our planned activities at Fort Berthold. The combination of these issues also impacted the pace of construction of our third-party gathering system at Fort Berthold which was originally expected in late spring, delaying tie-in activity and adding to our trucking costs in this area.

We invested $90 million in drilling, completions and tie-in activities during the quarter. We completed our 2011 drilling program in the Sleeping Giant field in Montana drilling two gross (1.5 net) operated horizontal wells. Four gross well completions in the area planned for the quarter were delayed until October, however, all are now on-stream and producing at a total rate of 2,200 BOE/day gross, 1,500 BOE/day net to Enerplus.

At Fort Berthold we drilled one long and six short Bakken horizontal wells and one long and two short Three Forks horizontal wells during the quarter. Three long and one short Bakken horizontal wells were completed during the quarter along with our first long Three Forks horizontal well. The long Three Forks well has produced over 25,000 barrels of oil in the first 30 days and had water cuts of approximately 30%, similar to those in the Bakken. Current production from this well is approximately 600 BOE/day with 1,200 psi flowing pressure. We continue to be pleased with the performance of our wells versus our estimated type curves. We also completed our first salt water disposal well late in the quarter. This well will allow us to reduce our trucking and water handling costs going forward. The completion of this disposal well, reduced drilling times due to the use of walking rigs and expected savings in rig moves, construction and tie-ins as a result of multi-well pads provide us with greater confidence in achieving our expected well costs of $6.7 million for short lateral wells and $8.7 million for long lateral wells, including tie-ins, despite upward cost pressures in this busy basin.

We currently have four rigs working at Fort Berthold and expect to maintain this rig count through the remainder of 2011 and into 2012. The build out of the first phase of the gathering system was completed by October and we have commenced gas sales from 14 of our producing wells. We anticipate that six of the 13 completions planned in the fourth quarter will also be tied into the gathering system immediately with the remainder tied in as compression facilities permit. We expect incremental production volumes of approximately 10% associated with the capture and sale of the natural gas once wells are tied into the gathering system.

Crude Oil Waterfloods

Our waterflood portfolio continues to be a core holding for Enerplus providing us with exposure to a variety of crude oil plays across western Canada that offer low decline production with significant upside potential. We invested $33 million in our waterflood portfolio during the quarter, drilling 14 net wells primarily targeting the Ratcliffe and Viking formations. Four net Ratcliffe wells were drilled and placed on-stream at Freda Lake with results that were 10% above our type curve expectations of 140 BOE/day per well. We expect to drill another four wells at Freda Lake through the end of the year. We also drilled five horizontal gross Viking wells at Gleneath with positive early test results.

Our polymer flood project at Giltedge is proceeding well. We're seeing polymer break through in a number of producing wells and we are now working to ensure the polymer is moving through the reservoir as efficiently as possible. We are encouraged by the early signs of improved oil production and reduced water cuts. Our annual production estimate at Giltedge has increased from 1,650 BOE/day to 1,900 BOE/day due to the polymer project and other optimization work. We have also increased our exit production outlook for the field by 600 BOE/day primarily due to these activities. As we see further reservoir response, we will evaluate our options of accelerating and/or expanding the next phase of enhanced oil recovery at Giltedge.

We have a busy program planned for the fourth quarter on our oil waterflood properties where we expect to drill 13 operated wells with the bulk of our activity focused on our Pembina, Virden, and Freda Lake properties. We will also continue constructing facilities at Medicine Hat to support the start-up of our second polymer flood project early in 2012.

Marcellus

We continued to see high activity levels in the Marcellus throughout the third quarter of 2011 with capital spending of $50 million on both our operated and non-operated leases. Our well results continue to exceed our expectations with net production growing by 3 MMcf/day, after adjusting for the sale of a portion of our interests late in the second quarter, to 15 MMcf/day in the third quarter. We participated in drilling 36 gross wells (4.5 net) with eight gross wells (1.1 net) coming on-stream. Although completion activity increased during the third quarter, there still continues to be a significant inventory of wells waiting to be completed and tied-in to pipelines due to the extremely wet spring and delays in pipeline gathering projects. We currently have 214 gross wells (15.5 net) waiting on completion and/or tie-in. Our current net production is 19 MMcf/day.

On our non-operated leases in the northeast region of Pennsylvania, drilling activity continued at a brisk pace with approximately 12 rigs working in the play. EXCO continues to run a three rig development program focused on multi-well pad drilling exclusively in Lycoming County. Both Chief and Chesapeake are also very active with three and six rigs running respectively in the northeast area of Pennsylvania focused primarily on lease retention strategies. The Marcellus continues to experience high levels of activity as producers drill to hold acreage and explore new step out areas and slowly move into development. There are currently 165 horizontal rigs running in the basin, concentrated in Pennsylvania and West Virginia. Well performance for the year in northeast Pennsylvania continues to outperform our expectations. Our partners are averaging 4,000 - 5,000 foot laterals, trending longer where acreage allows with an average of 8 - 15 frac stages. Chesapeake is extending the lateral length on their latest wells to approximately 6,000 feet. Current well costs in the northeast are ranging from $6.5 million to $8.0 million, slightly higher than previous quarters due to longer laterals and an extra casing string for water protection.

In our operated areas, we continue to run a one rig appraisal program and moved this rig from Clinton County, Pennsylvania to Preston County, West Virginia during the quarter. We drilled one well in southwest Preston County and are preparing to complete the well in early November. We also recently finished drilling our second well in the southeast area of Preston County and will start completion activities following rig release on our first well in southwest Preston County. Both of these wells are expected to be tied-in to pipeline by late in the first quarter of 2012. We plan to drill a third well in West Virginia before year-end and then move back to Clinton County to drill a second well during the winter. Work on our initial well in Clinton County has been completed. Our extended test showed a 24 hour peak rate of 8.3 MMcf/day (our expected 24 hour peak rate was 3.5 MMcf/day) with flowing tubing pressure of 2,600 psi.

Deep Tight Gas

We spent $20 million in delineation and development capital during the third quarter on both our operated and non-operated properties. We completed one operated well in the Bluesky formation at Ansell and initial production results of 4.2 MMcf/day are above our type curve. We also spudded a Wilrich horizontal well at Minehead, which is our first in the area and we expect to complete it in November with a late Q4/early Q1 expected tie-in. We also recently completed a vertical Stacked Mannville well at South Ansell where we're testing both the Gething and Cadomin zones. We plan to test the Wilrich zone in this well before the end of the year. This is an important delineation well for us as success here will provide added confidence for the potential development of South Ansell in 2012. We expect to drill a Montney test well at Cameron in the fourth quarter and will drill our first test in the Duvernay in 2012.

FOURTH QUARTER OUTLOOK

During the fourth quarter we expect to see a significant increase in production as a result of completion and tie-in activities, primarily in the U.S. At Fort Berthold we expect to bring 13 wells on-stream in November and December, nine Bakken and four Three Forks short horizontal wells. We also expect to add incremental production associated with field optimization activities. As a result of these activities, we expect production to grow by 5,000 - 8,000 BOE/day net by the end of December. In the Marcellus, tie-in activities by our operators are expected to accelerate in the fourth quarter with exit production in the range of 25 MMcf/day - 33 MMcf/day net to Enerplus. We expect approximately 24 additional gross wells in the Marcellus region (2.3 net wells) to come on-stream by year-end. In Canada, we plan to have approximately 23 net wells on-stream in the fourth quarter primarily in our crude oil waterflood properties targeting the Ratcliffe, Lodgepole and Viking formations. We also plan to test both the Montney and Stacked Mannville areas of the Deep Basin before year-end.

SUMMARY

While we've experienced a number of challenges in executing our 2011 capital program to date, we continue to be encouraged by our well results, the additional growth positions we have been able to build and the strength we have maintained in our financial position. We're excited about the prospects within our portfolio and the opportunity they represent for future growth in reserves, production and cash flow. We have a very active capital program planned for the fourth quarter that we expect will add significant production volumes to achieve our exit target of 81,000 - 84,000 BOE/day. While there continues to be much uncertainty and volatility in the capital markets as a result of debt issues in Europe and slow economic growth in the U.S., Enerplus is in a very strong financial position. We have preserved our balance sheet strength and are utilizing it to achieve our growth plans in the near term and believe we are on track to deliver on these plans.

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Corporation

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 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, 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 "Information Regarding Reserves, Resources and Operations" below.*

BARRELS OF OIL EQUIVALENT AND CUBIC FEET OF GAS EQUIVALENT

This news release also contains references to "BOE" (barrels of oil equivalent) and "cfe" (cubic feet of gas 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, and one barrel of oil to six thousand cubic feet of gas (1 bbl: 6 Mcf) when converting oil to cfes. BOEs and cfes 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.

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", "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: Enerplus' strategy to deliver both income and growth to investors and Enerplus' related asset portfolio; future capital and development expenditures and the timing and allocation thereof among our resource plays and assets; future development and drilling locations and plans; the performance of and future results from Enerplus' assets and operations, including anticipated production levels and decline rates; future growth prospects, acquisitions and dispositions; the volumes and estimated value of Enerplus' oil and gas reserves and contingent resource volumes and future commodity price and foreign exchange rate assumptions related thereto; the life of Enerplus' reserves; the volume and product mix of Enerplus' oil and gas production; securing necessary infrastructure and third party services; future cash flows and debt-to-cash flow levels; returns on Enerplus' capital program; and future costs and expenses.*

The forward-looking information contained in this news release reflect 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; 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' reserve and resource volumes; commodity price and cost assumptions; the continued availability of adequate debt and/or equity financing and cash flow to fund Enerplus' capital and operating requirements as needed; and the extent of its liabilities. 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 in commodity prices; changes in the demand for or supply of Enerplus' products; unanticipated operating results, results from development plans or production declines; 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; inaccurate estimation of Enerplus' oil and gas reserve and 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 certain other risks detailed from time to time in Enerplus' public disclosure documents (including, without limitation, those risks identified in Enerplus' Annual Information Form and Form 40-F described above).

The forward-looking information contained in this news release speak only as of the date of this news release, and none of Enerplus or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

NON-GAAP MEASURES

In this news release, we use the terms "funds flow" and "payout ratio" to analyze operating performance, leverage and liquidity. We calculate funds flow based on cash flow from operating activities before changes in non-cash operating working capital and decommissioning liabilities settled, all of which are measures prescribed by International Financial Reporting Standards ("IFRS") and which appear in our Consolidated Statements of Cash Flows. We calculate "payout ratio" by dividing dividends to shareholders by funds flow.

Enerplus believes that, in addition to net earnings and other measures prescribed by IFRS, the terms "funds flow", and "payout ratio" 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 IFRS and do not have a standardized meaning prescribed by IFRS. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers.