NEWS RELEASE

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FOR IMMEDIATE RELEASE

ENERPLUS ANNOUNCES 2011 FIRST QUARTER RESULTS

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 March 31, 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 "Information Regarding Reserves, Resources and Operations", "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. A full copy of our 2011 First 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.

Effective January 1, 2011, Enerplus converted from an income trust structure with the parent entity being Enerplus Resources Fund (the "Fund") to a corporate structure with the parent entity being Enerplus Corporation, as successor issuer to the Fund. As the Fund was the public entity in existence at December 31, 2010, all financial information as at and for the year ended December 31, 2010 is presented with respect to the Fund and its outstanding trust units at that time.

Calgary, Alberta - Enerplus Corporation ("Enerplus") (TSX: ERF) (NYSE: ERF) is pleased to announce operating and financial results for the three month period ended March 31, 2011. Highlights for the quarter were:

- Daily production averaged 75,483 BOE/day in line with expectations of 75,000 – 77,000 BOE/day despite challenges relating to extreme weather and unplanned plant outages. Production volumes were lower than the first quarter of 2010 due to the sale of over 10,400 BOE/day of non-core production, a significant amount of which occurred late in 2010.

- Approximately 44% of our total volumes were attributed to crude oil and natural gas liquids and we expect to see this percentage grow toward 50% as we execute our development program in 2011 and 2012.

- We continue to see positive results from our drilling activities in our U.S. Bakken assets, our waterflood properties in Canada and also in the Marcellus. We invested just over $174 million in our assets during the quarter, drilling 25.7 net wells, however only 4.8 net wells were brought on-stream during the quarter. Approximately 80% of our capital was directed to these three key plays with over 55% of our capital directed toward oil projects.

- High industry activity levels in key growth areas such as the U.S. Bakken are slowing our development programs. To help ensure the timely execution of our plans over the next two years, we have entered into long-term agreements to secure drilling rigs and frac services in North Dakota and Montana.

- Operating costs were below guidance of $9.20/BOE averaging $8.40/BOE mainly due to electricity hedging gains in the quarter and the divestment of higher operating cost properties in 2010.
- G&A costs averaged $3.79/BOE during the first quarter, higher than our guidance of $3.30/BOE mainly due to the IFRS accounting treatment for our rights incentive plan which was the predecessor to our current stock option plan.
- We generated funds flow of $161.2 million during the quarter, virtually unchanged from the fourth quarter of 2010.
- Approximately 60% of funds flow was paid to shareholders through our monthly dividends of $0.18/share with the remainder reinvested into our asset base. We also utilized our bank credit facilities to fund a portion of our capital spending program during the quarter.
- When combining our dividend and our capital spending, our adjusted payout ratio was 169%, in line with our expectations. As we continue to invest in earlier stage growth assets there is a longer lead time to production and funds flow. We expect our payout ratio will decline in 2012 and beyond as these growth plays deliver results.
- We sold undeveloped assets that had no significant production or cash flow during the quarter through a series of transactions for approximately $60 million.
- We continue to have a strong balance sheet with a debt-to-funds flow ratio of 1.2x at the end of the quarter, providing us with the financial flexibility to execute our capital spending plans throughout 2011 and 2012.
- We expect capital spending during the second quarter will be lower due to wet weather conditions across the Canadian prairies and into North Dakota, but anticipate increasing spending in the latter half of the year. We continue to forecast full year capital spending of $650 million. We currently do not expect this to have a significant impact on our annual production results and our operating guidance remains unchanged for 2011. We continue to expect to produce on average 78,000 – 80,000 BOE/day increasing to 80,000 – 84,000 BOE/day as we exit the year.

SELECTED FINANCIAL RESULTS

For the three months ended March 31,	**2011**	2010[(1)]
Financial (000's)		
Funds Flow [(2)]	**$161,224**	$198,281
Dividends to Shareholders	**96,686**	95,712
Net Income/(Loss)	**29,549**	(184,022)
Debt Outstanding – net of cash	**849,685**	517,263
Capital Spending	**174,444**	94,161
Property and Land Acquisitions	**48,218**	39,633
Divestments	**59,693**	1,538
Financial per Weighted Average Shares Outstanding		
Funds Flow [(2)]	**$0.90**	$1.14
Dividends	**0.54**	0.55
Net Income/(Loss)	**0.17**	(1.05)
Payout Ratio[(2)]	**60%**	48%
Adjusted Payout Ratio[(2)]	**169%**	96%

Selected Financial Results per BOE[3]		
Oil & Gas Sales[4]	**$46.92**	$47.65
Royalties	**(8.62)**	(8.57)
Commodity Derivative Instruments	**0.44**	0.51
Operating Costs	**(8.86)**	(9.91)
General and Administrative	**(3.28)**	(2.75)
Interest and Other Expenses	**(2.75)**	(0.93)
Taxes	**(0.12)**	-
Funds Flow	**$23.73**	$26.00
Weighted Average Number of Shares Outstanding	**178,832**	174,488
Debt to Trailing 12 Month Funds Flow	**1.2x**	0.7x[5]

SELECTED OPERATING RESULTS

For the three months ended March 31,	2011	2010
Average Daily Production		
Natural gas (Mcf/day)	**251,480**	298,920
Crude oil (bbls/day)	**30,338**	30,974
NGLs (bbls/day)	**3,232**	3,925
Total (BOE/day)	**75,483**	84,719
% Natural gas	**56%**	59%
Average Selling Price[4]		
Natural gas (per Mcf)	**$3.91**	$5.10
Crude oil (per bbl)	**77.69**	73.86
NGLs (per bbl)	**60.29**	57.47
US$/CDN$ exchange rate	**1.02**	0.96
Net Wells drilled	**26**	137

(1) 2010 comparative amounts have been restated and are presented in accordance with International Financial Reporting Standards ("IFRS"). In addition, 2010 comparatives represent the results of Enerplus Resources Fund which converted into Enerplus Corporation on January 1, 2011.
(2) See "Non-GAAP Measures" at the end of this news release.
(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 March 31, 2010, includes funds flow for April through December 2009 which were prepared following previous Canadian GAAP and which has not been restated in accordance with IFRS.

SHARE TRADING SUMMARY*	**CDN – ERF**	**U.S. - ERF**
For the three months ended March 31, 2011	(CDN$)	(US$)
High	$32.83	$33.29
Low	$27.48	$27.75
Close	$30.71	$31.66

* consolidated trading data presented

2011 CASH DIVIDEND SUMMARY

Payment Month	**CDN$/SHARE**	**US$/SHARE**
January	$0.18	$0.18
February	0.18	0.18
March	0.18	0.19
First Quarter Total	$0.54	$0.55

PRODUCTION AND CAPITAL SPENDING for the three months ended March 31, 2011

Play Type	Average Daily Production	Capital Spending ($ millions)
Bakken/Tight Oil (BOE/day)	13,595	66,600
Crude Oil Waterflood (BOE/day)	13,523	27,700
Conventional Oil (bbls/day)	6,537	2,800
Total Crude Oil & NGLs BOE/day)	33,655	97,100
Marcellus Shale Gas (Mcfe/day)	21,272	41,800
Other Natural Gas (Mcfe/day)	229,690	35,500
Total Gas (Mcfe/day)	250,962	77,300
Company Total (BOE/day)	75,483	174,400

NET DRILLING ACTIVITY for the three months ended March 31, 2011

Play Type	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in*	Wells Brought On-stream	Dry & Abandoned Wells
Bakken/Tight Oil	5.9	-	**5.9**	4.4	1.5	-
Crude Oil Waterfloods	8.5	0.3	**8.8**	6.7	2.1	-
Conventional Oil	1.0	-	**1.0**	-	1.0	-
Total Oil	**15.4**	**0.3**	**15.7**	**11.1**	**4.6**	**-**
Marcellus Shale Gas	5.1	-	**5.1**	5.1	-	-
Other Natural Gas	3.7	1.2	**4.9**	4.7	0.2	-
Total Gas	**8.8**	**1.2**	**10.0**	**9.8**	**0.2**	**-**
Company Total	**24.2**	**1.5**	**25.7**	**20.9**	**4.8**	**-**

*Wells pending potential completion/tie-in or abandonment and on-stream wells measured as at March 31, 2011

CRUDE OIL

Bakken/Tight Oil

Activity in our Bakken/tight oil resource play was lower than anticipated during the first quarter of 2011. Severe winter weather conditions and high industry activity combined to limit access to trucks in the Williston Basin. As a result, we experienced some production shut-ins and delays in moving in rigs. These factors have led to a slightly slower ramp up in activity at Fort Berthold, North Dakota than originally expected. We had two rigs working throughout the quarter and drilled four horizontal wells – two Bakken short laterals and one Bakken long lateral and our first short Three Forks lateral well. Two Bakken wells (one short lateral and one long lateral) drilled in the fourth quarter of 2010 were completed in the first quarter. Initial production rates of the long lateral averaged 1,154 bbls/day during the first 30 days and the short lateral well averaged 885 bbls/day, our best short lateral well rate to date. We own an average 90% working interest at Fort Berthold.

The following table illustrates the average cumulative production from the long and short lateral wells drilled and completed by Enerplus versus our original type well expectations. Our well results to date have either met or exceeded our original estimates. On average, we are seeing lower decline rates on these wells after three months than originally expected. As well, after eight months, we have exceeded our type well estimates by more than 45% on the short laterals and more than 30% on the long lateral wells. Crude oil prices have strengthened over the last year as well further improving the economics of these wells. Given the current commodity price environment, we expect long lateral wells to achieve payout on average in less than one year and short lateral wells to achieve payout in approximately 1.7 years.

Fort Berthold Cumulative Production Results To Date*

	30 Day Avg Cum. Prod/Well	60 Day Avg Cum. Prod/Well	120 Day Avg Cum. Prod/Well	180 Day Avg Cum. Prod/Well	240 Day Avg Cum. Prod/Well
Short Laterals					
Original Type Well Est. (Mbbls)	17	26	40	50	59
Actual Well Results (Mbbls)	22	35	53	75	87
Number of Wells	6	5	5	4	4
Long Laterals					
Original Type Well Est. (Mbbls)	34	53	81	103	121
Actual Well Results (Mbbls)	37	58	100	126	162
Number of Wells	5	5	3	3	2

*gross volumes and wells, prior to deduction of royalty interests

We currently have two rigs working at Sleeping Giant in Montana where we plan to drill seven horizontal wells this year. We plan to move two additional rigs into Fort Berthold in the second quarter and anticipate running with a minimum of four rigs for the remainder of the year. Planned infrastructure and gathering system build out continues to proceed at Fort Berthold. By mid-summer we expect to have a majority of our wells tied-in to a central gathering facility reducing our reliance on trucking in the region.

In total, we expect to drill and complete approximately 28 horizontal wells at Fort Berthold during the remainder of the year, targeting both the Bakken and the Three Forks formations (75% long lateral wells) and will also be testing downspacing. With the additional rigs and our frac services agreement in place, drilling and completions activity has begun to accelerate and we should remain on schedule for the balance of the year, drilling and completing two to four wells per month. High activity levels in the region may continue to put upward pressure on costs, however, we continue to expect to spend approximately $250 million in North Dakota and Montana in 2011.

Production volumes averaged approximately 13,600 BOE/day, unchanged from volumes reported at year end. Since acquiring our interests and assuming operatorship approximately one year ago, we have drilled eight horizontal wells in the Fort Berthold area and completed another four wells drilled by the previous operator. Production has grown from approximately 1,100 bbls/day to over 4,500 bbls/day primarily as a result of our successful drilling activities.

Waterfloods

Production from our waterflood properties was on track with our expectations for the first quarter averaging approximately 13,500 BOE/day. We spent approximately $28 million on drilling, completions and facilities during the quarter. We drilled 8.8 net wells primarily targeting light oil in the Cardium and the Ratcliffe.

At our Pembina Cardium waterflood, we successfully completed the drilling of a six well program and completed three of these wells during the quarter. We are currently evaluating the results from these wells and early indications are positive. In Saskatchewan, we drilled and completed three horizontal wells into the Ratcliffe trend at our Freda Lake waterflood. Initial 30 day production results are meeting expectations ranging from 200 – 300 bbls/day from each well. Our battery expansion at Freda Lake was completed and we have an additional 11 wells planned this year. Activities at our Giltedge polymer project continued during the quarter. We began injection on schedule in April and expect to see first production response sometime in the fourth quarter. Work is also underway at our second polymer project at Medicine Hat with start-up planned for early 2012. At year end, Enerplus had identified incremental and enhanced oil recovery potential of over 60 million BOE of contingent resources associated with a portion of our waterflood portfolio, providing over 70% upside to our proved plus probable waterflood reserves at December 31, 2010.

NATURAL GAS

Marcellus

The Marcellus play area continued to be very active through the first quarter of 2011 as our partners continued to drill wells to retain and develop leases. We are experiencing positive drilling results and better than expected decline rates on our base production with volumes for the first quarter slightly ahead of expectations averaging 21.3 MMcfe/day up from 2010 exit volumes of 17.6 MMcfe/day net to Enerplus.

We participated in drilling 21 gross wells (approximately 5 net) with our partners Chief Oil & Gas and Exco during the quarter. The majority of this activity was in northeastern Pennsylvania where initial production rates and expected ultimate recoveries have been generally above our type curve. Completion and tie-in activities were slower than anticipated with only one net non-operated well completed due to winter weather conditions and continued delays with pipeline construction. We currently have 52 gross wells on production with over 70% of our production volumes from wells drilled in the northeastern region of Pennsylvania. Another 48 gross wells are either waiting on completion or are in the process of completion and a further 20 gross wells are waiting on tie-in. We continue to expect a significant level of drilling activity in 2011 focusing on lease retention and delineation drilling. We currently have ten rigs operating in the play, nine with our partners plus one operated rig.

The table below illustrates the cumulative performance of the majority of wells that are currently on production. Production from the northeastern Pennsylvania counties has either met or exceeded estimates with Susquehanna county wells materially outperforming the type curve the longer the wells are on production. The production volumes presented do not include any associated natural gas liquids. While the volumes in Marshall and Greene Counties appear to be slightly under our type well expectations, the associated natural gas liquids in this area combined with lower well costs support economic returns for these wells.

Marcellus Cumulative Production Results*

	30 Day Avg Cum. Prod/Well	60 Day Avg Cum. Prod/Well	90 Day Avg Cum. Prod/Well	120 Day Avg Cum. Prod/Well	180 Day Avg Cum. Prod/Well
NE Pennsylvania – Susquehanna County					
Type Well Estimate (MMcf)	169	310	431	539	725
Actual (MMcf)	195	431	685	910	1,347
Well Count	4	4	3	3	3
NE Pennsylvania - Lycoming County					
Type Well Estimate (MMcf)	142	260	361	451	608
Actual (MMcf)	101	213	329	433	622
Well Count	19	19	18	16	15
NE Pennsylvania - Bradford County					
Type Well Estimate (MMcf)	130	238	331	414	557
Actual (MMcf)	80	199	317	435	622
Well Count	13	13	13	10	4
W. Virginia/ SW PA - Marshall/Greene County					
Type Well Estimate (MMcf)	115	210	292	365	492
Actual (MMcf)	98	180	262	344	467
Well Count	11	11	11	9	6

*of horizontal wells only and gross volumes before deduction of royalty interests.

On our operated leases, we are planning a modest delineation program in 2011 focusing on our acreage in central Pennsylvania and Preston County, West Virginia. We successfully completed our first operated well in Clinton County (5,300 foot lateral length with an eight stage frac) which had a peak test rate of approximately 3.8 MMcf/day. With the lack of pipeline infrastructure in this area, we do not expect to tie-in this well until early 2012. We also began drilling the first of two wells in Centre County in Pennsylvania and will follow these wells with three wells in the southern part of Preston County in West Virginia.

Other Natural Gas

Activities on our Canadian natural gas assets were mainly related to non-operated drilling in the liquids rich Deep Basin area. We participated in a total of eight gross non-operated wells (2.4 net wells) in this area and also finished our operated two well program at Tommy Lakes. Well results from our non-operated partners have been encouraging particularly as a number of these wells are close to our Ansell/Minehead properties. Given the positive drilling results to date, we expect further drilling activity by our partners in this region and will continue to assess this activity as it relates to our surrounding lands. We expect to allocate some additional capital to delineate a portion of our Stacked Mannville lands. Enerplus currently holds over 80,000 net acres of operated land prospective for either the Montney or the Stacked Mannville.

SUMMARY

2011 will be a very active year for Enerplus as we execute one of our largest capital programs in our history. In April we announced a number of changes to our senior leadership team, including the promotion of Mr. Ian Dundas to the position of Executive Vice-President and Chief Operating Officer. I am confident that our leadership team, combined with the technical and commercial acumen of our staff, can deliver results. Our foundation of mature assets is providing us with a stable platform to support our business strategy. We are actively pursuing our development plans in new growth plays and are encouraged by our results to date. With our successful conversion to a corporation effective January 1, 2011, we are confident that we can create value for our shareholders through our growth and income strategy.

For further information, please contact our Investor Relations Department at 1-800-319-6462 or email investorrelations@enerplus.com.

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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 gross (or, as noted above, "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, 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.*

INFORMATION REGARDING RESERVES, RESOURCES AND OPERATIONS

Barrels of Oil Equivalent and Cubic Feet of Gas Equivalent

This news release also contains references to "BOE" (barrels of oil equivalent) and "Mcfe" (thousand 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 Mcfes. BOEs and Mcfes 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.

Contingent Resource 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 economic, 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." There is no certainty that we will produce any portion of the volumes currently classified as "contingent resources". The "contingent resource" estimates contained herein are presented as the "best estimate" of the quantity that will actually be recovered, effective as of December 31, 2010. 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 information regarding the primary contingencies which currently prevent the classification of our disclosed "contingent resources" associated with our crude oil waterflood assets as reserves and the positive and negative factors relevant to the "contingent resource" estimate, see our Annual Information Form for the year ended December 31, 2010 (and corresponding Form 40-F), a copy of which is available on our SEDAR profile at www.sedar.com and a copy of the Form 40-F which is available on our EDGAR profile at www.sec.gov. There are a number of inherent risks and contingencies associated with the development of our interests in these properties including commodity price fluctuations, project costs, our ability to make the necessary capital expenditures to develop the properties, reliance on our industry partners in project development, acquisitions, funding and provisions of services and those other risks and contingencies described above, and that apply generally to oil and gas operations as described above, and under "Risk Factors" in our Annual Information Form referred to above.

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; our future adjusted payout ratio; 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", "payout ratio" and "adjusted 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. "Adjusted payout ratio" is calculated as dividends to shareholders plus capital spending and office expenditures, divided by funds flow.

Enerplus believes that, in addition to net earnings and other measures prescribed by IFRS, the terms "funds flow", "payout ratio" and "adjusted 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.