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NEWS RELEASE

November 12, 2010

ENERPLUS ANNOUNCES OPERATING AND FINANCIAL RESULTS FOR THIRD QUARTER 2010

CALGARY, Nov. 12 /CNW/ - Enerplus Resources Fund ("Enerplus") (TSX - ERF.un, NYSE - ERF) is pleased to announce operating and financial results for the third quarter of 2010. Full copies of our third quarter 2010 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.

TRANSITIONING THE ASSET BASE

- To date this year Enerplus has acquired over $900 million of new growth-oriented assets in two of the best plays in North America - the Bakken crude oil play in the Williston Basin and the Marcellus shale gas play in northeast United States. The proceeds from our disposition activities have ensured we maintain our strong financial position while repositioning into higher growth assets and improving the focus in our portfolio.
- We expanded our interest in the Marcellus shale gas region with the purchase of 58,500 net acres of high working interest land in West Virginia and Maryland. We now own and operate a total of 70,000 net acres of concentrated land in addition to the nearly 130,000 net acres of non-operated land in the Marcellus which will provide us with significant future growth potential.
- We also acquired 46,500 net acres of additional land in the Fort Berthold area of North Dakota subsequent to the quarter that we believe is prospective for both Bakken and Three Forks crude oil. This complements our existing operated position in the region and gives Enerplus over 70,000 net acres of undeveloped land in North Dakota together with 140,000 net acres of undeveloped Bakken prospective land in the Freda Lake/Neptune/Oungre area of southern Saskatchewan that we operate as well.
- We added 39 sections of land prospective for natural gas from the Stacked Mannville and Montney formations. We now hold over 65,000 net acres of undeveloped land in the Deep Basin area.
- 2,500 BOE/day of oil and gas production located in Alberta and British Columbia was sold during the quarter for proceeds of $153 million. As well, we expect to close the sale of a further 4,500 BOE/day of non-core assets during the fourth quarter for proceeds of approximately $140 million. The average operating cost of these properties ranged from $17.00/BOE to $23.00/BOE.
- We were also successful in selling our Kirby oil sands lease for $405 million subsequent to the quarter.

OPERATING AND FINANCIAL PERFORMANCE

- Operations continued to meet expectations with production volumes in line with guidance. Operating costs have continued to decline throughout the year and our capital program has delivered results in key growth areas as well as in mature, cash flow generating assets.
- Production averaged 82,869 BOE/day after adjusting for the sale of 2,500 BOE/day of production during the third quarter. To date in 2010, we've sold 6,000 BOE/day of non-core production.
- We had an active quarter spending $128 million in development capital, 80% of which was invested in our Bakken/tight oil, Marcellus and crude oil waterflood resource plays. Year-to-date capital investment has totaled $314 million, the majority of which has been funded from cash flow.
- 25 net wells were drilled, 85% of which were oil wells. All but one of these wells were drilled horizontally.
- Cash flow from operations totaled $203.6 million for the third quarter. For the first nine months of 2010, Enerplus has generated approximately $556.3 million of cash flow from operating activities, distributing 52% to unitholders through monthly distributions.
- Development capital spending and distributions totaled 110% of cash flow for the third quarter and 108% for the first nine months of the year.
- Operating costs averaged $10.28/BOE for the quarter with year-to-date costs averaging $10.02/BOE.
- Our balance sheet remains strong with a debt to cash flow ratio of 0.9x at September 30, 2010 providing us with ample financial flexibility to pursue our future growth plans.

SELECTED FINANCIAL RESULTS	**Three months ended September 30,**		**Nine months ended September 30,**	
(in Canadian dollars)	**2010**	2009	**2010**	2009
Financial (000's)				
Cash Flow from Operating Activities	**$203,622**	$207,211	**$556,362**	$587,207

Cash Distributions to Unitholders[1]	**96,111**	93,504	**287,732**	272,651
Excess of Cash Flow Over Cash Distributions	**107,511**	113,707	**268,630**	314,556
Net Income	**16,808**	38,182	**128,107**	86,399
Debt Outstanding - net of cash	**680,264**	561,218	**680,264**	561,218
Development Capital Spending[2]	**127,837**	42,863	**313,650**	174,316
Property and Land Acquisitions[2]	**140,530**	195,038	**493,731**	228,783
Divestments	**150,747**	519	**333,523**	2,255
Actual Cash Distributions paid to Unitholders	**$0.54**	$0.54	**$1.62**	$1.69
Financial per Weighted Average Trust Units[3]				
Cash Flow from Operating Activities	**$1.14**	$1.23	**$3.13**	$3.52
Cash Distributions per Unit[1]	**0.54**	0.55	**1.62**	1.63
Excess of Cash Flow Over Cash Distributions	**0.60**	0.68	**1.51**	1.89
Net Income	**0.09**	0.23	**0.72**	0.52
Payout Ratio[4]	**47%**	45%	**52%**	46%
Adjusted Payout Ratio[2][4]	**110%**	68%	**108%**	78%
Selected Financial Results per BOE [5]				
Oil & Gas Sales[6]	**$40.08**	$35.23	**$42.96**	$35.36
Royalties	**(7.29)**	(5.56)	**(7.74)**	(6.10)
Commodity Derivative Instruments	**2.76**	4.89	**1.84**	5.08
Operating Costs	**(10.09)**	(10.00)	**(10.03)**	(9.84)
General and Administrative	**(2.55)**	(2.21)	**(2.22)**	(2.18)
Interest and Other Expenses	**(1.88)**	(0.79)	**(1.51)**	(0.22)
Taxes Recovery/(Expense)	**4.43**	(0.35)	**1.45**	(0.22)
Asset Retirement Obligations Settled	**(0.30)**	(0.31)	**(0.44)**	(0.34)
Cash Flow from Operating Activities before changes in non-cash working capital	**$25.16**	$20.90	**$24.31**	$21.54
Weighted Average Number of Trust Units Outstanding[3]	**177,871**	168,521	**177,526**	166,724
Debt to Trailing Twelve Month Cash Flow Ratio	**0.9x**	0.7x	**0.9x**	0.7x

SELECTED OPERATING RESULTS	**Three months ended September 30,**		**Nine months ended September 30,**	
	2010	2009	**2010**	2009
Average Daily Production				
Natural gas (Mcf/day)	**285,292**	323,884	**293,543**	333,606
Crude oil (bbls/day)	**31,639**	32,218	**31,393**	33,454
Natural gas liquids (bbls/day)	**3,681**	3,912	**3,842**	4,129
Total daily sales (BOE/day)	**82,869**	90,111	**84,159**	93,184
% Natural gas	**57%**	60%	**58%**	60%
Average Selling Price [6]				
Natural gas (per Mcf)	**$3.67**	$2.95	**$4.19**	$3.86
Crude oil (per bbl)	**66.97**	64.94	**69.80**	55.57
NGLs (per bbl)	**46.69**	32.59	**50.61**	36.21
CDN$/US$ exchange rate	**0.96**	0.91	**0.97**	0.85
Net Wells drilled	**25.0**	27.6	**183.8**	156.6

(1) Calculated based on distributions paid or payable.

(2) Land acquisitions in prior periods have been reclassified from development capital expenditures to property acquisitions to conform with the current year presentation.

(3) Weighted average trust units outstanding for the period, includes the equivalent exchangeable limited partnership units.

(4) Payout ratio is calculated as cash distributions to unitholders divided by cash flow from operating activities. Adjusted payout ratio is calculated as the sum of cash distributions to unitholders plus development capital and office expenditures divided by cash flow from operating activities. See "Non-GAAP Measures" below.

(5) Non-cash amounts have been excluded.

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

TRUST UNIT TRADING SUMMARY	**TSX - ERF.un**	**U.S.* - ERF**
For the three months ended September 30, 2010	(CDN$)	(US$)
High	$26.57	$25.84
Low	$22.53	$20.90
Close	$26.50	$25.75

* U.S. Composite Exchange Data including NYSE.

2010 CASH DISTRIBUTIONS PER TRUST UNIT

Payment Month	**CDN$**	**US$**
First Quarter Total	**$0.54**	**$0.52**
Second Quarter Total	**$0.54**	**$0.53**
July	$0.18	$0.17
August	0.18	0.18
September	0.18	0.17
Third Quarter Total	**$0.54**	**$0.52**
Total Year-to-Date	**$1.62**	**$1.57**

PRODUCTION AND DEVELOPMENT CAPITAL SPENDING

	Three months ended Sept. 30, 2010		**Nine months ended Sept. 30, 2010**	
Play Type	**Average Production Volumes**	**Capital Spending ($ millions)**	**Average Production Volumes**	**Capital Spending ($ millions)**
Bakken/Tight Oil (BOE/day)	13,039	51	10,722	115
Crude Oil Waterfloods (BOE/day)	13,979	28	15,209	64
Conventional Oil (BOE/day)	8,029	3	9,068	9
Total Oil (BOE/day)	35,047	82	34,999	188
Marcellus Shale Gas (Mcfe/day)	11,230	26	6,783	61
Shallow Gas (Mcfe/day)	116,313	6	121,805	14
Tight Gas (Mcfe/day)	82,647	12	86,437	41
Conventional Gas (Mcfe/day)	76,741	2	79,935	10
Total Gas (Mcfe/day)	286,931	46	294,960	126
Company Total	82,869	128	84,159	314

DRILLING ACTIVITY

Net wells drilled for the three months ended Sept. 30, 2010

Play Type	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in*	Wells On-stream	Dry & Abandoned Wells
Bakken/Tight oil	11.7	-	11.7	10.7	1.0	-
Crude Oil Waterfloods	6.2	-	6.2	3.1	3.1	-
Conventional Oil	2.6	-	2.6	2.6	-	-
Total Oil	**20.5**	**-**	**20.5**	**16.4**	**4.1**	**-**
Marcellus Shale Gas	2.4	1.0	3.4	3.4	-	-
Shallow Gas	-	-	-	-	-	-
Tight Gas	0.9	-	0.9	0.9	-	-
Conventional Gas	0.2	-	0.2	0.2	-	-
Total Gas	**3.5**	**1.0**	**4.5**	**4.5**	**-**	**-**
Company Total	**24.0**	**1.0**	**25.0**	**20.9**	**4.1**	**-**

* includes wells that are pending evaluation

BAKKEN/TIGHT OIL

The Bakken/tight oil resource play continues to be a key growth driver within Enerplus. Production from this play has increased by approximately 50% this year as a result of our successful development program and our acquisition activities. We expect significant growth in production and reserves from this resource play in the future.

Overall we are very encouraged by the results of our drilling program in North Dakota. At Fort Berthold, five horizontal wells were drilled during the quarter - three operated long horizontal wells and two short horizontal wells associated with our recent acquisition. In addition, two wells drilled in the second quarter were brought on stream. We now have nine wells drilled into this play, six of which have been completed to date. The lateral length of these wells has ranged from 4,300 feet with 12 frac stages for the short lateral wells to 9,000 feet with 24 frac stages for the long lateral wells.

Actual production results shown in the table below continue to either meet or materially exceed our type curve estimates. Production from the long lateral wells was limited due to fluid handling capacity.

	Expected 30 Day Average Production Rate/Well	Actual 30 Day Average Production Rate/Well	Actual 60 Day Average Production Rate/Well
Short Lateral Wells (4 wells)	650 bbls/day	800 bbls/day	650 bbls/day
Long Lateral Wells (2 wells)	1,200 bbls/day	1,190 bbls/day	1,100 bbls/day

First 100 day cumulative production from our two long Bakken lateral wells totaled 101,000 and 91,000 barrels of oil respectively. We continue working on our frac design and procedures, but have been very encouraged to date with rates and flowing pressures.

Gathering infrastructure work is underway both on and off the Fort Berthold Indian Reservation with midstream companies to build the necessary infrastructure to allow us to capture produced gas and additional crude oil volumes. We anticipate the first well tie-ins will occur late in the fourth quarter and continue into 2011. Current production from Enerplus' Fort Berthold area is approximately 4,000 bbls/day.

We currently have two rigs active in Fort Berthold, both drilling multi-well pads. We plan to add an additional rig at our Sleeping Giant property in Montana in December which will move to Fort Berthold after drilling one to two development wells. Access to service crews continues to be a challenge due to the high activity levels in the Williston Basin. Given our sizeable land position as a result of our recent acquisitions, we believe we can mitigate this issue given our anticipated increase in spending over the next three to five years. We expect to have long term service agreements in place by year end that will help us execute our plans going forward. Production from this area is expected to grow to over 20,000 BOE/day over the next five years.

In Canada, our activities have been focused on conducting an appraisal of the lands acquired earlier this year through the drilling of a number of delineation wells and shooting 3-D seismic. We haven't been able to drill and complete as many wells as originally planned on our Saskatchewan Bakken lands and the results to date have been mixed. Weather has proved to be a significant challenge over the summer as extremely wet conditions made well sites difficult to access. Three horizontal wells were drilled during the quarter, however completion activities were delayed. We are currently in the process of completing these wells. The completion results and the seismic information will help us evaluate the potential of the Saskatchewan land and define future plans for the play.

MARCELLUS SHALE GAS

Activity in our Marcellus shale gas play during the third quarter increased from the second quarter with 14 gross wells drilled (3.4 net wells) and development spending of $26 million. Production volumes have also increased significantly, averaging over 11 MMcf/day during the quarter, almost double the levels we realized in the second quarter.

The majority of our joint venture activities were concentrated in Lycoming and Susquehanna counties this quarter. In

addition to the 14 gross wells that were drilled and awaiting tie in, six gross wells drilled earlier in the year were also tied in. Early results indicate these six wells are meeting our performance expectations with peak 24 hour test rates averaging over 6.2 MMcf/day. Another seven gross wells were completed and are currently awaiting tie-in. To date, 93 wells have been drilled across nine counties in Pennsylvania (Lycoming, Bradford, Susquehanna, Wyoming, Clearfield, Blair, Somerset, Greene and Fayette) as well as Marshall County in West Virginia. Expected ultimate recoveries range from 3.75 Bcf to 7 Bcf per well, varying by county, Marcellus thickness and lateral length. As discussed earlier this year, lateral lengths and the number of frac stages are increasing with the most recent wells ranging from 4,300 to 5,800 foot lateral lengths with 10 to 15 frac stages. As a result of the longer lateral length and increased frac stages, well costs are trending higher, however initial production rates and expected ultimate recoveries are increasing as well. There are currently 42 wells on production, 15 wells waiting on pipeline and 36 wells waiting on completion. Another 20 wells are being drilled or remain to be drilled in 2010, with activity planned for northeast Pennsylvania, south central Pennsylvania, and Marshall County, West Virginia.

Similar to our experience in the Bakken play, high activity levels have strained service company availability and impacted our completions activity. A number of wells were only partially completed during the quarter due to crew availability and will now be completed in the fourth quarter of 2010 or the early part of 2011. As a result, some volumes anticipated at year end may now come on production in early 2011. We currently have eight rigs running in the play and expect an additional rig may be added before the end of the year. Production volumes in early November were approximately 16 MMcf/day.

Enerplus operated activity commenced with construction on the pad site of our first operated horizontal well in Clinton County, Pennsylvania during the quarter. Drilling is currently underway with a planned horizontal length of 4,500 feet.

WATERFLOODS

Our waterflood projects continue to be a core focus area within Enerplus' portfolio, representing approximately 18% of our daily production volumes. Approximately $64 million has been spent year to date drilling 26 net wells and improving/expanding facilities to support our future plans. As a result of our 2010 capital investment activities, we expect production volumes will be maintained year-over-year excluding production volumes sold through our disposition program.

During the third quarter, the majority of our activities occurred at our Freda Lake Ratcliffe property in Saskatchewan. Six horizontal wells have been drilled in the last year (three in the third quarter) resulting in a 140% increase in production from approximately 500 bbls/day at the start of 2010 to 1,200 bbls/day currently. Three dual lateral wells and three single lateral wells have been drilled with 30 day initial production rates of 200 to 300 bbls/day from the dual lateral wells. We are in the process of completing the single lateral wells and expect initial production rates of over 100 bbls/day. To date, the decline rates have also been better than expected. Our activities have also included facility upgrades and increased production and water handling capacity in order to accommodate the current and future increases in production volumes. We plan to drill another five single lateral wells in the fourth quarter in addition to 11 injector well conversions. Our Saskatchewan land acquisitions earlier this year also added acreage with rights to the Ratcliffe formation which will enhance our future development plans in this area. Based upon our current acreage, we see two to three years of drilling potential similar to this year's activity that will maintain production volumes.

We also commenced a horizontal drilling program at our Gleneath waterflood property. This waterflood has been producing exclusively from vertical wells drilled into the Viking light crude oil formation. We drilled and completed two horizontal wells during the third quarter. Initial flowing test rates indicate these wells could produce approximately 100 bbls/day per well once they are placed on pump, in line with our 30 day type curve. We plan to drill another four wells during the fourth quarter. Depending upon the success of this activity, we believe there are 20 to 30 future drilling locations at Gleneath.

OUTLOOK FOR THE REMAINDER OF 2010

As we announced in September, we expect annual production to average 83,000 to 84,000 BOE/day, with an exit rate of 80,000 to 82,000 BOE/day taking into account the impact of the assets we sold or expect to sell this year. Service crew availability remains a challenge and could pose a potential for delays in completing a number of high impact wells in the Bakken and Marcellus regions. Should we experience delays in obtaining services and also given the level of capital spending planned for the fourth quarter of this year we may be challenged to spend our entire capital budget in 2010. If this occurs, exit production rates would be impacted but with the expectation that the planned activities would be completed early in 2011. We continue to expect to invest $515 million in development capital in 2010 with operating cost and G&A cost guidance of $10.20/BOE and $2.45/BOE respectively.

CORPORATE CONVERSION

On September 30, 2010, we formally announced our plans to convert to a dividend paying corporation January 1, 2011. We plan to hold a Special Meeting of Unitholders on December 9, 2010 in Calgary, Alberta to vote on the conversion and, subject to Unitholder approval and obtaining all of the necessary Court and regulatory approvals, we would convert to a corporation effective January 1, 2011. We have proposed a straight forward conversion to our Unitholders. We will exchange one trust unit of Enerplus Resources Fund for one share in Enerplus Corporation. This exchange will be tax-deferred and will not result in a capital gain or loss to our Unitholders. Our ticker symbols will remain the same as will our corporate brand. Further, the conversion will not result in the acceleration or vesting of any compensation or incentive based awards to any employees or Directors of Enerplus. We intend to continue to pay monthly dividends to investors after the conversion and expect to maintain the current rate of $0.18/share through the conversion. This dividend level is based upon commodity prices, debt levels, capital spending and other factors and may fluctuate in the future. We will also utilize our available tax pools to mitigate our Canadian cash tax obligations and do not expect to incur cash taxes in Canada for three to five years after conversion. For more information on the conversion and how to cast your vote, details can be found at www.enerplus.com. We look forward to your support on December 9th.

CONSOLIDATED FINANCIAL STATEMENTS AND MD&A

Third quarter 2010 Consolidated Financial Statements and Notes to the Consolidated Financial Statements, along with the Management's Discussion and Analysis for Enerplus, have been filed on our website at www.enerplus.com, under our profile on SEDAR www.sedar.com and on the EDGAR website at www.sec.gov.

INFORMATION REGARDING DISCLOSURE IN THIS NEWS RELEASE

All amounts in this news release are stated in Canadian dollars unless otherwise specified.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading. "Mcfe" means thousand cubic feet of gas equivalent. Enerplus has adopted the standard of one barrel of oil to six thousand cubic feet of gas (1 barrel: 6 Mcf) when converting oil to Mcfes. Mcfes may be misleading, particularly if used in isolation. An Mcfe conversion ratio of 1 barrel: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Under Canadian disclosure requirements and industry practice, production is reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The practice in the United States is to report production using net volumes, after deduction of applicable royalties and similar payments.

Readers are also urged to review the Management's Discussion & Analysis and financial statements for the three and nine months ended September 30, 2010 filed on SEDAR and EDGAR concurrently with this news release for more complete disclosure on our operations.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release contains certain forward-looking information and statements 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" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: Enerplus' strategy and future growth potential in production and reserves; the expected disposition of certain non-core assets in the fourth quarter of 2010; future drilling plans and prospects and well tie-ins; our ability to mitigate shortages in service crews; future production levels and increases, including average 2010 and year-end 2010 exit production levels; capital expenditure levels and the timing thereof; operating and G&A costs; the conversion of Enerplus from an income trust to a corporation, the timing thereof and the tax treatment to unitholders; the amount and timing of cash dividends to Enerplus shareholders; and the Fund's income taxes, tax liabilities and tax pools. This press release also contains estimates of contingent resources, which are by their nature estimates that the quantities described exist in the amounts estimated.

The forward-looking information and statements contained in this news release reflect several material factors and expectations and assumptions of Enerplus including, without limitation: that Enerplus will continue to conduct its operations in a manner consistent with past operations; the general continuance of current or, where applicable, assumed industry conditions and tax and regulatory regimes; availability of cash flow, debt and/or equity sources to fund Enerplus' capital and operating requirements as needed; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; that there will be willing buyers of certain of Enerplus' oil and gas assets on terms acceptable to Enerplus; that all required conditions to complete the conversion of Enerplus from a trust to a corporation will be obtained or satisfied; the accuracy of the estimates of Enerplus' reserve and resource volumes; acquisition and disposition activity and certain commodity price and other cost assumptions. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable at this time but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this news release are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve 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 or statements including, without limitation: changes in commodity prices; unanticipated operating results or production declines; changes in tax or environmental laws or royalty rates; increased debt levels or debt service requirements; failure to complete anticipated asset sales; failure to obtain all necessary approvals and satisfy all conditions for the conversion of Enerplus from an income trust to a corporation; inaccurate estimates of tax pools and future income tax liabilities; inaccurate estimation of Enerplus' oil and gas reserves and resources volumes; limited, unfavourable or no access to debt or equity capital markets; increased costs and expenses; the impact of competitors; reliance on industry partners including a continued shortage of service crews; and certain other risks detailed from time to time in the Fund's public disclosure documents including, without limitation, those risks identified in our MD&A for the three and nine months ended September 30, 2010, our MD&A for the year ended December 31, 2009 and in the Fund's Annual Information Form for the year ended December 31, 2009, copies of which are available on the Fund's SEDAR profile at www.sedar.com and which also form part of the Fund's Form 40-F for the year ended December 31, 2009 filed with the SEC, a copy of which is available at www.sec.gov.

The forward-looking information and statements contained in this news release speak only as of the date of this release and none of the Fund 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

Throughout this news release we use the term "payout ratio" and "adjusted payout ratio" to analyze operating performance, leverage and liquidity We calculate payout ratio by dividing cash distributions to Unitholders ("cash distributions") by cash flow from operating activities ("cash flow"), both of which appear on our consolidated statements of cash flows prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). "Adjusted payout ratio" is calculated as cash distributions plus development capital and office expenditures divided by cash flow. The terms "payout ratio" and "adjusted payout ratio" do not have a standardized meaning or definition as prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other entities. Refer to the Liquidity and Capital Resources section of our Management's Discussion and Analysis for the three and nine months ended September 30, 2010 for further information.

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Resources Fund

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