

NEWS RELEASE

ENERPLUS CORPORATION
The Dome Tower, Suite 3000
333 – 7th Avenue SW
Calgary, Alberta T2P 2Z1
T. 403-298-2200 F. 403-298-2211
www.enerplus.com

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FOR IMMEDIATE RELEASE

Enerplus Exceeds Operating & Financial Targets for 2013

All financial information contained within this news release has been prepared in accordance with U.S. GAAP including comparative figures pertaining to Enerplus' 2012 results. This news release includes forward-looking statements and information within the meaning of applicable securities laws. Readers are advised to review the "Forward-Looking Information and Statements" at the conclusion of this news release. Readers are also referred to "Information Regarding Reserves, Resources and Operational Information", "Notice to U.S. Readers" and "Non-GAAP Measures" at the end of this news release for information regarding the presentation of the financial, reserves, contingent resources and operational information in this news release. A full copy of our 2013 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") (TSX: ERF) (NYSE: ERF) is pleased to announce fourth quarter 2013 results as well as 2013 year-end operating and financial results.

2013 KEY TAKEAWAYS:

- **Funds flow per share grew by 14%**
- **Production grew by 9%, exceeding guidance in spite of non-core asset sales**
- **Proved plus probable reserves were up 17% year-over-year, replacing 284% of 2013 production**
- **Capital spending, operating costs and general and administrative costs were all reduced**
- **Debt to funds flow ratio at year-end improved to 1.4x**

4TH QUARTER 2013:

- Production continued to grow during the fourth quarter of 2013 averaging 94,167 BOE per day, up 7% from the previous quarter and 10% compared to the same period in 2012. Production during the month of December averaged 99,569 BOE per day, ahead of our exit guidance of 95,000 BOE per day. Marcellus production exceeded our expectations, producing 170 MMcf per day during the month of December including the additional working interests acquired in late November. Crude oil and natural gas liquids volumes were virtually unchanged quarter over quarter, despite the sale of 900 barrels per day of crude oil in Canada. As a result of the higher volumes from the Marcellus, our production weighting to natural gas increased to 56% during the fourth quarter.
- We invested \$223 million in capital projects during the quarter, with over two thirds of the spending directed to oil projects. A total of 18 net wells were drilled, with 19 net wells brought on-stream.
- Funds flow totaled \$181 million during the fourth quarter, down 8% from the previous quarter. Despite the growth in production volumes, a widening of crude oil differentials resulted in a decrease of almost 20% in our average realized crude oil price compared to the previous quarter.
- Cash operating costs and general and administrative expenses per BOE were both down compared to the third quarter, averaging \$10.46 and \$2.28 per BOE, respectively.

- We closed a number of transactions during the fourth quarter including the acquisition of additional working interests in our Marcellus natural gas properties for \$158 million. Through this acquisition, we added 17,000 net acres in existing properties in northeast Pennsylvania with approximately 42 MMcf per day of natural gas production.
- We also closed the sale of non-core producing assets in Canada for proceeds of \$104 million. In addition, we entered into an agreement to sell our undeveloped Montney acreage in British Columbia for \$135 million, after adjustments, of which \$66 million closed during the quarter with the remainder closed in January of 2014.

2013 SUMMARY:

- We delivered annual production growth of 9% in 2013, exceeding both our annual and exit production forecasts for the year. Daily production averaged 89,800 BOE, ahead of guidance of 89,000 BOE per day. Total oil production increased by 5% in 2013 to average 38,250 barrels per day, despite the sale of 2,700 BOE per day of non-core oil production.
- Natural gas production increased by 15% to average 288 MMcf per day for the year, representing 54% of our annual production volumes. Strong well performance in the Marcellus combined with the acquisition of additional working interests in December helped to drive this result.
- Funds flow grew by 17% year-over-year to \$754 million due to the increase in production volumes, lower costs and an increase in commodity prices. On a per share basis, this was a 14% increase.
- Capital spending came in slightly lower than our forecast of \$685 million, totaling \$681 million. Approximately 70% of our spending was directed to our crude oil assets with the majority invested at Fort Berthold, North Dakota. We invested 82% of our budget on drilling and completion activities, with 62 net wells drilled and brought on-stream across our asset base.
- We continued to concentrate our portfolio throughout 2013. We sold \$365 million of non-core assets, redeploying \$245 million to increase our working interests in our crude oil waterflood portfolio and in the Marcellus. This also includes additional acreage acquired in the Wilrich, Marcellus and Bakken/Three Forks plays. Our net acquisition and divestment activities realized gross proceeds of \$120 million in 2013.
- Our capital efficiencies improved again in 2013. Based upon our capital spending and the growth in production volumes from the fourth quarter of 2012 to the same period in 2013, this reflects a capital efficiency of approximately \$26,000 per daily BOE.
- With the increase in funds flow, a reduction in capital spending and improved capital efficiencies, our adjusted payout ratio improved to 114% in 2013 including participation in our Stock Dividend Plan ("SDP"). Monthly dividends to shareholders were maintained throughout the year, totaling \$1.08 per share and represented 23% of funds flow including the SDP.
- As a result of the growth in funds flow and the net proceeds from our divestment activities, our financial flexibility increased in 2013. Approximately 80% of our bank credit facility was undrawn and our trailing twelve month debt-to-funds-flow ratio fell to 1.4 times at year-end, down from 1.7 times at year-end 2012.
- Our proved plus probable ("2P") company interest reserves increased by 17% at year-end, replacing 284% of our 2013 average daily production.
- Finding and development costs including future development capital ("FDC") were \$11.28 per BOE. When divided by our corporate netback of \$27.40 per BOE, this reflects a 2.4x recycle ratio.
- Finding, development and acquisition costs, including FDC, were \$8.36 per BOE.
- The net present value of our future net revenues discounted at 10% before tax increased by 7% in 2013 to approximately \$5 billion.

SELECTED FINANCIAL RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2013	2012	2013	2012
Financial (000's)				
Funds Flow	\$180,741	\$200,411	\$754,233	\$644,523
Cash and Stock Dividends	54,665	53,572	216,864	301,560
Net Income	29,626	34,637	47,976	(270,697)
Debt Outstanding - net of cash	1,022,308	1,064,365	1,022,308	1,064,365
Capital Spending	223,035	160,934	681,437	853,455
Property and Land Acquisitions	173,387	121,391	244,837	185,337
Property Divestitures	168,050	220,135	365,135	275,771
Debt to Trailing 12 Month Funds Flow	1.4x	1.7x	1.4x	1.7x
Financial per Weighted Average Shares Outstanding				
Funds Flow	\$0.89	\$1.01	\$3.76	\$3.29
Net Income	0.15	0.17	0.24	(1.38)
Weighted Average Number of Shares Outstanding (000's)	202,257	198,256	200,567	195,633
Selected Financial Results per BOE⁽¹⁾⁽²⁾				
Oil & Natural Gas Sales ⁽³⁾	\$43.79	\$45.86	\$48.11	\$44.56
Royalties	(7.46)	(7.28)	(8.06)	(7.06)
Production Taxes	(2.07)	(2.26)	(2.15)	(1.89)
Commodity Derivative Instruments	1.90	2.04	0.81	0.61
Operating Costs	(10.46)	(9.14)	(10.50)	(10.51)
General and Administrative	(2.28)	(2.34)	(2.54)	(2.61)
Share Based Compensation	(1.06)	(0.03)	(0.71)	(0.18)
Interest and Other Expenses	(1.51)	(1.45)	(1.71)	(1.42)
Taxes	0.01	0.08	(0.24)	(0.05)
Funds Flow	\$20.86	\$25.48	\$23.01	\$21.45

SELECTED OPERATING RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2013	2012	2013	2012
Average Daily Production⁽²⁾				
Crude oil (bbls/day)	37,731	38,597	38,250	36,509
NGLs (bbls/day)	3,813	3,576	3,472	3,627
Natural gas (Mcf/day)	315,739	259,904	288,423	251,773
Total (BOE/day)	94,167	85,490	89,793	82,098
% Crude Oil & Natural Gas Liquids	44%	49%	46%	49%
Average Selling Price⁽²⁾⁽³⁾				
Crude oil (per bbl)	\$ 77.77	\$ 76.75	\$ 83.99	\$ 78.19
NGLs (per bbl)	54.26	47.31	52.25	53.01
Natural gas (per Mcf)	3.26	3.01	3.26	2.39
Net Wells drilled	18	11	62	75

⁽¹⁾ Non-cash amounts have been excluded.

⁽²⁾ Based on Company interest production volumes.

⁽³⁾ Net of oil and gas transportation costs, but before royalties and the effects of commodity derivative instruments.

	Three months ended December 31,		Twelve months ended December 31,	
	2013	2012	2013	2012
Average Benchmark Pricing				
WTI crude oil (US\$/bbl)	\$97.46	\$88.18	\$97.97	\$94.21
AECO- monthly index (CDN\$/Mcf)	3.16	3.06	3.16	2.40
AECO- daily index (CDN\$/Mcf)	3.53	3.22	3.17	2.39
NYMEX- monthly NX3 index (US\$/Mcf)	3.63	3.36	3.67	2.80
USD/CDN exchange rate	1.05	0.99	1.03	1.00

SHARE TRADING SUMMARY

For the twelve months ended December 31, 2013

CDN* – ERF

(CDN\$)

U.S. - ERF**

(US\$)

High	\$19.96	\$18.79
Low	\$12.26	\$12.03
Close	\$19.30	\$18.18

* TSX and other Canadian trading data combined.

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

2013 DIVIDENDS PER SHARE
CDN\$
US\$⁽¹⁾

First Quarter Total	\$0.27	\$0.27
Second Quarter Total	\$0.27	\$0.26
Third Quarter Total	\$0.27	\$0.26
Fourth Quarter Total	\$0.27	\$0.26
Total	\$1.08	\$1.05

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

2013 PRODUCTION & CAPITAL SPENDING

	Q4 2013 Average Production	2013 Annual Average Production	2013 Exit Production*	2013 Capital Spending (\$million)
Crude Oil & NGLs (Bbls/day)				
Canada	19,561	20,663	18,958	172.9
United States	21,983	21,059	21,455	316.2
Total Crude Oil & NGLs (Bbls/day)	41,544	41,722	40,413	\$489.1
Natural Gas (Mcf/day)				
Canada	165,114	175,876	161,965	113.7
United States	150,625	112,547	192,967	78.7
Total Natural Gas (Mcf/day)	315,739	288,423	354,932	\$192.4
Company Total (BOE/day)	94,167	89,793	99,569	\$681.4

*December month

2013 NET DRILLING ACTIVITY***

	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in *	Wells On-stream**	Dry & Abandoned Wells
Crude Oil						
Canada	20.9	.2	21.1	1.8	18.6	-
United States	20.3	-	20.3	4.5	24.7	-
Total Crude Oil	41.2	.2	41.4	6.3	43.3	-
Natural Gas						
Canada	11.5	-	11.5	6.2	5.6	-
United States	9.3	-	9.3	5.6	12.7	-
Total Natural Gas	20.8	-	20.8	11.8	18.2	-
Company Total	62.0	.2	62.2	18.1	61.5	-

* Wells drilled during the year that are pending potential completion/tie-in or abandonment as at December 31, 2013.

** Total wells brought on-stream during the year regardless of when they were drilled.

*** Table may not add due to rounding.

ASSET ACTIVITY

Our 2013 capital program was focused in our four core areas – the U.S. Bakken/Three Forks, the Marcellus, our Canadian crude oil waterfloods and our deep gas opportunities within the Deep Basin region of Alberta. Our single largest capital investment was once again in North Dakota where we allocated 45% of our capital budget to continue development of the Bakken and Three Forks zones. Our program was focused on improving capital efficiencies through a reduction in well costs and increased productivity. We continued to evolve our well completion design in North Dakota throughout 2013 and through these changes and focused cost management, we were able to deliver a 50% increase in the average 30 day initial production rate while still reducing total well costs by 8% on average in

2013. The changes have driven a 40% improvement in capital efficiencies year-over-year. We grew production from this region by over 30% in 2013. We also added 25 MMBOE of 2P reserves at a cost of \$19.74 per BOE including future development capital. With an average netback of approximately \$53 per BOE in 2013, this delivered a 2.7x recycle ratio.

We continued to invest in the Marcellus throughout 2013, concentrating our drilling activity within the most economic areas in northeastern Pennsylvania. Well costs improved year-over-year decreasing by approximately 20% through a combination of pad drilling and lower costs. As well, production rates continued to exceed our expectations throughout the year. A total of 9 net wells were drilled in 2013, with 13 net wells tied in and brought on-stream. Despite a widening of the basis differentials in the region given constrained take-away capacity, we continue to see robust economics from our drilling program. The majority of our drilling activity was focused in Bradford, Susquehanna and Sullivan counties with average 30 day initial production rates increasing by approximately 60% year-over-year to almost 10 MMcf per day in these counties. Production during the month of December averaged 170 MMcf per day of natural gas, driven by the acquisition of additional working interests and the tie-in of 6 net wells in the fourth quarter. Through our development and acquisition activities, we added 411 Bcf of 2P reserves at a cost of \$0.91 per Mcf including future development capital. This reflects a 2.2x recycle ratio based upon our average netback of \$2.00 per Mcf from the Marcellus in 2013. Our Marcellus production represents approximately 50% of both our corporate natural gas volumes and our 2P natural gas reserves.

Our activities in Canada were predominately directed to our crude oil waterflood projects where we advanced our enhanced oil recovery project at Medicine Hat and continued with our drilling and optimization programs at our Freda Lake, Pembina, and Giltedge properties. We also drilled 4 net wells in the Wilrich and in the Duvernay, we drilled two vertical wells, one horizontal re-entry and spud one horizontal well in 2013 to advance our understanding of these emerging plays.

RESERVES AND CONTINGENT RESOURCE ASSESSMENT

Our total 2P reserves increased by over 17% year-over-year, driven by significant reserve additions in the Marcellus and also in our Bakken/Three Forks properties in North Dakota. At December 31, 2013, Enerplus' independent reserve evaluators had assessed 406 million BOE of 2P company interest reserves attributable to our asset base. Additional information on our 2013 reserves can be found in our news release dated February 3, 2014.

In addition to the 2P reserves, an assessment of the additional resource potential within a portion of our asset base has identified 363 MMBOE of economic, best estimate contingent resources ("contingent resources") as of December 31, 2013. This quantity of contingent resources is essentially unchanged from year-end 2012, despite converting approximately 70 MMBOE of contingent resources to reserves. Based upon our forecast production volumes for 2014, this would represent approximately 10 years of organic reserve replacement potential currently existing within a portion of our portfolio today.

Our contingent resource assessment includes:

- 39 MMBOE of contingent resources attributable to both the Bakken and Three Forks at Fort Berthold. 18 MMBOE of previously assessed contingent resources were converted to reserves in 2013 and 23 MMBOE of new contingent resources were added primarily associated with the Three Forks formation. This assessment assumes a well density of two wells per drilling spacing unit within the Bakken and two wells per spacing unit within the first bench of the Three Forks formation only. We believe further upside potential may exist through both increased drilling density and also drilling into the lower benches in the Three Forks.
- 59 MMBOE of contingent resources attributable to improved oil recovery ("IOR") and enhanced oil recovery ("EOR") in our Canadian waterflood assets. Approximately 4 MMBOE of previously assessed contingent resources were converted to reserves in 2013.
- 1.3 Tcf of contingent resources associated with our Marcellus natural gas assets. We added approximately 290 Bcf of contingent resources associated with the acquisition of additional working interests and reclassified 258 Bcf of contingent resources to reserves as a result of our successful drilling activity.
- 253 Bcf of contingent resources associated with our Wilrich deep gas assets in Canada. Approximately 30 Bcf of contingent resources were reclassified to reserves in 2013 as a result of our successful drilling activities.

At this time, there has been no assessment of the resource potential within our Duvernay land position.

2014 OUTLOOK

We expect to produce an average of 96,000 – 100,000 BOE/day in 2014, an increase of 9% year-over-year or 8% per share using the mid-point of this range. We expect continued growth from our U.S. oil properties at Fort Berthold where we anticipate that average annual production will increase by approximately 30% in 2014, driving our light crude oil volumes to 67% of our total oil production. Total crude oil and natural gas liquids production is expected to increase by approximately 12%. Natural gas production is expected to increase by 7% averaging over 300 MMcf per day with the majority of the growth attributable to the Marcellus. Our U.S. assets are anticipated to account for over 50% of our corporate production volumes in 2014. The production mix is expected to remain at approximately 48% crude oil and natural gas liquids and 52% natural gas although continued outperformance in the Marcellus could push the natural gas share higher.

The improvement in asset quality and operational performance along with our focus on cost reductions and productivity enhancements has resulted in a significant improvement in capital efficiencies across our portfolio. We plan to build on these improvements in 2014 to deliver another year of profitable growth complemented by a meaningful dividend to our investors. Our plans include investing \$760 million in capital projects in 2014 with two thirds of our budget directed to oil projects in North Dakota and in our Canadian waterfloods. The remainder of our budget will be directed to our core natural gas assets in the Marcellus and in the Deep Basin region as we move into development in the Wilrich and continue to evaluate the Duvernay. Given that approximately 55% of our planned capital spending is in the U.S., continued weakness in the Canadian dollar could put upward pressure on our 2013 spending which is reported in Canadian dollars, although it would also have a positive effect on reported revenues.

Hedging Update

We continue to hedge a portion of our crude oil and natural gas production in order to provide downside protection to our funds flow estimates. As of February 4, 2014, we have swapped approximately 59% of our net crude oil production for 2014, after royalties, at an average price of US\$94.02 per barrel. We also have downside protection on approximately 40% of our forecasted natural gas production after royalties for 2014. Full details on our hedging contracts are contained within our 2013 Annual MD&A & Financial Statements which have been filed on SEDAR and EDGAR.

Changes to Board of Directors

We are pleased to announce that Ms. Hilary Foulkes has joined the Board of Directors of Enerplus. Ms. Foulkes has over 30 years of experience within the Canadian oil and gas industry focused in the areas of exploration, development and investment banking. She is a professional geologist and earned a Bachelor of Science (Honours, Earth Sciences) from the University of Waterloo.

Live Conference Call

Ian C. Dundas, President and CEO, will host a conference call today, February 21, 2014 at 9:00 a.m. MT (11:00 a.m. ET) to discuss these results. Details of the conference call are as follows:

Date: Friday, February 21, 2014
 Time: 9:00 am MT/11:00 am ET
 Dial-In: 647-427-7450
 1-888-231-8191
 Audiocast: <http://www.newswire.ca/en/webcast/detail/1298449/1432621>

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 podcast of the conference call will also be available on our website for downloading following 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: 58756618

Electronic copies of our 2013 year-end MD&A and Financial Statements, along with other public information including investor presentations, are available on our website at www.enerplus.com. For further information, please contact Investor Relations at 1-800-319-6462 or email investorrelations@enerplus.com.

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

INFORMATION REGARDING RESERVES, RESOURCES AND OPERATIONAL INFORMATION

Currency and Accounting Principles

All amounts in this news release are stated in Canadian dollars unless otherwise specified. All financial information in this news release has been prepared and presented in accordance with U.S. GAAP, except as noted below under "Non-GAAP Measures".

Barrels of Oil Equivalent

This news release also contains references to "BOE" (barrels of oil equivalent). 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. "MBOE" and "MMBOE" mean "thousand barrels of oil equivalent" and "million barrels of oil equivalent", respectively.

Presentation of Production and Reserves Information

Under U.S. GAAP oil and gas sales are generally presented net of royalties and U.S. industry protocol is to present production volumes net of royalties. Under IFRS and Canadian industry protocol oil and gas sales and production volumes are presented on a gross basis before deduction of royalties. In order to continue to be comparable with 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. Unless otherwise specified, all reserves volumes in this news release (and all information derived therefrom) are based on "company interest reserves" using forecast prices and costs. "Company interest reserves" consist of "gross reserves" (as defined in NI 51-101), being Enerplus' working interest before deduction of any royalties, plus Enerplus' royalty interests in reserves. "Company interest reserves" are not a measure defined in NI 51-101 and do not have a standardized meaning under NI 51-101. Accordingly, our company interest reserves may not be comparable to reserves presented or disclosed by other issuers. Our oil and gas reserves statement for the year ended December 31, 2013, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, is contained within our Annual Information Form for the year ended December 31, 2013 ("**our AIF**") which is available on our website at www.enerplus.com and under our SEDAR profile at www.sedar.com. Additionally, our AIF forms part of our Form 40-F that is filed with the U.S. Securities and Exchange Commission and is available on EDGAR at www.sec.gov. Readers are also urged to review the Management's Discussion & Analysis and financial statements filed on SEDAR and as part of our Form 40-F on EDGAR concurrently with this news release for more complete disclosure on our operations.*

Contingent 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 ultimate recovery rates, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. All of our contingent resource estimates are economic using established technologies and under current commodity price assumptions used by our independent reserve evaluators. Enerplus expects to develop these contingent resources in the coming years however it is too early in their development for these resources to be classified as reserves at this time. There is 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, 2013. A "best estimate" of contingent resources means that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

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

See "Non-GAAP Measures" below.

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 in SEC filings, whereas Canadian issuers may disclose oil and gas resources. Resources are different than, and should not be construed as reserves. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, contingent resources, see "Information Regarding Reserves, Resources and Operational Information" 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' asset portfolio; future capital and development expenditures and the allocation thereof among our assets; future development and drilling locations, plans and costs; the performance of and future results from Enerplus' assets and operations, including anticipated production levels, expected ultimate recoveries 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; future funds flow and debt-to-funds flow levels; potential asset acquisitions and dispositions; rates of return on Enerplus' capital program; Enerplus' tax position; sources of funding of Enerplus' capital program; and future costs, expenses and royalty rates.

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; 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, cash flow and other sources 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 realized prices for Enerplus' products; 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 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; 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 described above).

The purpose of certain financial outlook information included in this news release, including with respect to our 2014 guidance for funds flow, is to communicate our current expectations as to our performance in 2014. Readers are cautioned that it may not be appropriate for other purposes. The forward-looking information contained in this news release speaks only as of the date of this news release, and none of Enerplus or its subsidiaries assume 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", "adjusted payout ratio", "capital efficiency", "recycle ratio" and "netback" 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. "Adjusted payout ratio" is calculated as cash dividends to shareholders, net of our stock dividends and DRIP proceeds, plus capital spending (including office capital) divided by funds flow. "Capital efficiency" is calculated as the change in production from the fourth quarter of the previous year to the fourth quarter of the current year divided by total capital expenditures from the fourth quarter of the previous year up to and including the third quarter of the current year. "Netback" is calculated as oil and gas revenues after deducting royalties, operating costs and transportation expenses. A "recycle ratio" is calculated as finding and development costs divided by operating netback.

Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "funds flow", "adjusted payout ratio", "capital efficiency", "netback" and "recycle 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 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.