enerPLUS

NEWS RELEASE

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FOR IMMEDIATE RELEASE

ENERPLUS REPLACES 175% OF 2011 PRODUCTION THROUGH DRILL BIT

This news release includes forward-looking statements and information within the meaning of applicable securities laws. Readers are advised to review the "Cautionary Note Regarding 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 2011 Financial Statements and MD&A have been filed on our website at www.enerplus.com, under our profile on SEDAR at www.sedar.com and on the EDGAR website at www.sec.gov.

Calgary, Alberta - Enerplus Corporation ("Enerplus") (TSX: ERF) (NYSE: ERF) is pleased to announce 2011 year-end reserves, operating and financial results.

RESERVES/RESOURCES

- Total proved plus probable reserves ("2P") at December 31, 2011 increased by 5% to 321.9 MMBOE year-over-year and 4% on a per share basis.
- 2P oil and liquids reserves grew by 14% to total 184.8 MMBOE and now represent 57% of total 2P reserves, up from 53% at year-end 2010.
- We replaced 175% of production through our exploration and development program, adding 48 MMBOE of 2P reserves. Approximately 75% of the additions were oil and liquids and represented a 300% replacement of our 2011 oil and liquids production. The largest amount of reserve additions came from our Fort Berthold crude oil property in North Dakota.
- We sold 5.2 MMBOE of 2P reserves in 2011, including 23 Bcfe associated with our Marcellus disposition. After dispositions, we replaced 157% of 2011 production volumes.
- Despite a 30% decrease in the forecast price for natural gas, the estimated net present value ("NPV") of future net revenues from our reserves (discounted at 10%, before taxes) increased by almost 10% as a result of the increased weighting of light sweet crude oil reserves in our portfolio. The NPV of our oil properties in the U.S. rose by nearly 50% primarily as a result of our successful drilling activities.
- Over and above our 2P reserves, our best estimate of contingent resources associated with our tight oil, waterflood and Marcellus resource plays at December 31, 2011 totaled 485 MMBOE representing 150% of our booked 2P reserves.
- Our 2P reserve life index was 9.8 years at year-end, down from 10.7 years at December 31, 2010 as a result of the addition of higher decline production from our new growth plays and a decrease in shallow gas reserves.
- As a result of the weak outlook for natural gas prices, approximately 33 Bcfe of natural gas reserves were removed from our reserve report at year-end. Total natural gas 2P reserves declined by 5% year-over-year.

- Our 2P Finding and Development costs ("F&D") excluding future development capital ("FDC") were $17.22/BOE, reflecting the significant positive additions delivered from our new growth plays in North Dakota and in the Marcellus.
- Our 2P F&D costs including FDC were $26.26/BOE. In 2011, approximately $150 million of our capital spending related to projects that did not add reserves in 2011. This amount was disproportionately higher than normal mainly due to spending in the Marcellus and North Dakota and the timing of wells coming on-stream.
- Our 2P Finding, Development and Acquisition costs ("FD&A") without FDC were $8.57/BOE and $17.89/BOE with FDC, reflecting the significant value captured in the sale of our Marcellus interests which had minimal reserves.

OPERATIONS

- We made significant progress growing our production base organically during 2011. We entered the year with production of 77,200 BOE/day and exited producing approximately 82,000 BOE/day. Our annual average production was 75,332 BOE/day, slightly less than our guidance of 76,000 BOE/day as we experienced execution delays during the first half of the year on key projects.
- Our exploration and development capital spending in 2011 totaled approximately $866 million, $96 million higher than our guidance of $770 million. The increase was due to higher fourth quarter activity levels supported by favourable weather conditions including accelerated spending on permitting, regulatory work and equipment inventory along with approximately $35 million of cost increases related to our U.S. Bakken properties.
- We invested approximately $720 million on drilling and completions activities during 2011 with 106.8 net wells drilled, 74% of which were drilled on our crude oil properties.
- We continued to focus our asset base during 2011 through our acquisition and divestment activities. We spent approximately $112.5 million adding 133,000 undeveloped acres in emerging plays in Canada to support our future growth. We also sold assets for aggregate proceeds of $641 million, with $568 million coming from our second quarter Marcellus disposition where we recognized a gain of $272 million.
- At December 31, 2011, we held a portfolio of approximately 380,000 net acres of strategic land comprised of 75,000 net acres at Fort Berthold targeting the Bakken and Three Forks, 65,000 net acres in the Duvernay, 33,000 net acres in the Montney, 67,000 net acres in the Stacked Mannville, 30,000 net acres in the Cardium and other emerging oil plays in Canada and 110,000 net acres in the Marcellus.
- Favourable weather conditions during the fourth quarter drove high levels of activity in our field operations. As a result, we experienced increased costs related to well servicing, repairs and maintenance and higher than expected Alberta power costs. Our annual operating costs were $10.23/BOE for the year compared to guidance of $9.60/BOE.

FINANCIAL

- Cash flow from operating activities for 2011 totaled $623 million, down from $696 million in 2010. Stronger oil prices in 2011 were offset by lower natural gas prices and lower average production levels due to the full year impact of 2010 dispositions along with approximately $60 million of taxes related to gains on our dispositions in our U.S. subsidiary.
- We maintained our monthly dividend at $0.18/share throughout 2011, paying $2.16/share in total and representing a payout ratio of approximately 68% of funds flow.
- Our adjusted payout ratio, which calculates dividends plus capital spending divided by funds flow, was 221% for 2011. However, after including our net acquisition and disposition activity, our adjusted payout ratio was 153%. Our payout ratio has increased year-over-year as a result of our significant investment in early stage growth assets that are not generating immediate production or cash flow. This has been compounded due to the decline in natural gas prices.
- Despite the reduction in cash flow we continued to maintain our balance sheet strength with a trailing twelve month debt-to-funds flow ratio of 1.6x at year-end. At December 31, 2011 we had $554 million of available

credit under our bank credit facility. We believe we also have the ability to increase the size of our bank facility should we choose.

- During 2011 our price risk management program generated cash gains of $13 million on natural gas contracts and cash losses of $47 million on crude oil contracts. We have continued to add crude oil hedge positions and approximately 62% of our projected crude oil production in 2012 has downside protection at an average floor price of US$96.22 . In addition, we have approximately 10% of our 2013 crude oil production hedged at an average price of US$101.20. We have no natural gas hedge positions in place at this time.

- As a result of lower natural gas prices, we recorded a $334 million non-cash impairment on our Canadian natural gas operations in 2011. Under International Financial Reporting Standards ("IFRS") impairment charges related to capital assets are reversed in future periods if conditions causing the impairment change, such as a recovery in natural gas prices.

- On February 8, 2012 we closed a $345 million equity financing to help fund our 2012 capital program and maintain our financial flexibility.

SELECTED FINANCIAL RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2011	2010[1]	**2011**	2010[1]
Financial (000's)				
Funds Flow [2]	**$156,682**	$162,606	**$573,609**	$728,968
Cash Flow from Operating Activities	**242,192**	142,033	**623,440**	696,183
Dividends to Shareholders	**97,725**	96,396	**388,904**	384,127
Net Income/(Loss)	**(299,415)**	64,500	**109,437**	(179,282)
Debt Outstanding - net of cash	**901,465**	724,031	**901,465**	724,031
Exploration and Development Capital Spending	**344,837**	225,926	**865,712**	536,436
Property and Land Acquisitions	**45,263**	522,847	**255,209**	1,012,272
Divestments	**3,082**	537,935	**641,190**	871,458
Financial per Weighted Average Shares Outstanding				
Funds Flow [2]	**$0.87**	$0.92	**$3.19**	$4.15
Dividends	**0.54**	0.55	**2.16**	2.19
Net Income/(Loss)	**(1.66)**	0.37	**0.61**	(1.02)
Weighted Average Number of Shares Outstanding	**180,845**	176,648	**179,889**	175,736
Debt to Trailing 12 Month Funds Flow[2]	**1.6x**	1.0x	**1.6x**	1.0x
Payout Ratio[2]	**62%**	59%	**68%**	53%
Adjusted Payout Ratio[2]	**284%**	234%	**221%**	127%
Selected Financial Results per BOE[3]				
Oil & Gas Sales[4]	**$50.29**	$42.49	**$48.85**	$42.85
Royalties	**(9.62)**	(6.20)	**(8.92)**	(7.36)
Commodity Derivative Instruments	**(1.54)**	1.02	**(1.21)**	1.64
Operating Costs	**(11.64)**	(8.42)	**(10.33)**	(9.66)
General and Administrative	**(3.05)**	(3.48)	**(2.99)**	(2.76)
Interest and Other Expenses	**(1.70)**	(2.95)	**(1.59)**	(1.69)
Taxes	**(0.68)**	(0.40)	**(2.95)**	1.00
Funds Flow[2]	**$22.06**	$22.06	**$20.86**	$24.02

SELECTED OPERATING RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2011	2010	**2011**	2010
Average Daily Production				
Crude oil (bbls/day)	**31,715**	30,368	**30,181**	31,135
NGLs (bbls/day)	**3,256**	4,027	**3,306**	3,889
Natural gas (Mcf/day)	**253,500**	274,314	**251,068**	288,692
Total (BOE/day)	**77,221**	80,114	**75,332**	83,139
% Crude Oil & Natural Gas Liquids	**45%**	43%	**44%**	42%
Average Selling Price[4]				
Crude oil (per bbl)	**$87.56**	$72.18	**$83.48**	$70.38
NGLs (per bbl)	**68.32**	53.66	**64.99**	51.41
Natural gas (per Mcf)	**3.41**	3.63	**3.72**	4.05
US$/CDN$ exchange rate	**0.98**	0.99	**1.01**	0.97
Net Wells drilled	**36**	40	**107**	225

(1) 2010 comparative amounts have been restated and are presented in accordance with International Financial Reporting Standards ("IFRS") and represent the results of Enerplus Resources Fund which converted into Enerplus Corporation on January 1, 2011.
(2) See "Non-GAAP Measures" in the accompanying MD&A.
(3) Non-cash amounts have been excluded.
(4) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

SHARE TRADING SUMMARY	CDN*	U.S.**
For the twelve months ended December 31, 2011	(CDN$)	(US$)
High	$32.83	$33.29
Low	$23.00	$21.65
Close	$25.85	$25.32

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

2011 CASH DIVIDENDS PER SHARE

Payment Month	CDN$	US$
First Quarter Total	$0.54	$0.55
Second Quarter Total	$0.54	$0.55
Third Quarter Total	$0.54	$0.55
Fourth Quarter Total	$0.54	$0.53
Total Year-to-Date	$2.16	$2.18

US$ dividends represent CDN$ dividends converted at the relevant foreign exchange rate on the payment date

2011 PRODUCTION & CAPITAL SPENDING

Play Type	2011 Annual Average	2011 Exit	2011 Exit vs 2010 Exit	2011 Capital ($million)
Tight Oil (BOE/day)	13,616	16,703	26%	375
Crude Oil Waterfloods (BOE/day)	15,127	16,760	22%	164
Conventional Oil (BOE/day)	4,661	4,761	-20%	19
Total Oil (BOE/day)	**33,404**	**38,224**	**16%**	**$558**
Marcellus Shale Gas (Mcfe/day)	20,524	25,213	43%	210
Other Natural Gas (Mcfe/day)	231,040	237,798	-4%	98
Total Gas (Mcfe/day)	**251,564**	**263,011**	**-1%**	**$308**
Company Total	**75,332**	**82,059**	**6%**	**$866**

2011 NET DRILLING ACTIVITY*

Play Type	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in *	Wells On-stream**	Dry & Abandoned Wells
Tight Oil	34.0	-	34.0	4.8	30.8	-
Crude Oil Waterfloods	33.8	0.3	34.1	9.0	31.9	0.5
Conventional Oil	11.2	0.1	11.3	4.9	8.6	-
Total Oil	**79.0**	**0.4**	**79.4**	**18.7**	**71.3**	**0.5**
Marcellus Shale Gas	16.0	-	16.0	13.9	5.3	–
Other Natural Gas	9.0	2.4	11.4	3.7	52.8	-
Total Gas	**25.0**	**2.4**	**27.4**	**17.6**	**58.1**	**-**
Company Total	**104.0**	**2.8**	**106.8**	**36.3**	**129.4**	**0.5**

*Wells drilled during the year that are pending potential completion/tie-in or abandonment as at December 31, 2011
** Total wells brought on-stream during the year regardless of when they were drilled

KEY RESOURCE PLAY ACTIVITY

Tight Oil – Fort Berthold

We invested approximately $290 million at Fort Berthold during 2011 targeting both the Bakken and Three Forks light crude oil formations, representing the single largest capital investment area in our portfolio. A total of 25 net operated wells were drilled (18 short lateral wells and 7 long lateral wells) with approximately 21 net wells brought on stream during the year. As a result of our successful drilling activities, we more than doubled the reserves in this property adding 33 MMBOE of 2P reserves plus an additional 3 MMBOE added due to technical revisions for a total of 36 MMBOE of 2P reserve additions at a cost of $19.16/BOE. We converted 30 MMBOE of our Bakken contingent resources to reserves, leaving 30 MMBOE of contingent resources attributable to the Bakken. We also added 19 MMBOE of contingent resources attributable to the Three Forks for a total of 49 MMBOE of independently assessed contingent resources at Fort Berthold at December 31, 2011. These contingent resources represent 78 future drilling locations over and above the 52 booked drilling locations in our 2P reserve report based primarily upon a drilling density of two wells per drilling spacing unit in both the Bakken and Three Forks formations. Given the drilling density to date, we assumed a land utilization of 90% for the Bakken and only 35% for the Three Forks given the limited well control at this time. Enerplus has approximately 115 net sections of land in the Fort Berthold region with less than 50 wells currently on production.

Our Bakken well results have typically outperformed our expectations throughout 2011. As a result, we have increased our expected ultimate recovery ("EUR") estimates for Bakken wells in this area to 800,000 bbls/long lateral well and 400,000 bbls/short lateral well which is at the high end of our previous expectations. These estimates are based upon drilling two wells per spacing unit. Five Three Forks wells (one long and four short) were brought on-stream in 2011. The long lateral well averaged 800 BOE/day during the first 30 days of production and the four short lateral wells averaged 450 BOE/day during the first 30 days. These results essentially met our expectations which assumed Three Forks wells would produce approximately 70% of a Bakken well. Two multi-well pads were drilled to test various well densities and communication between the Bakken and Three Forks formations however further production run time is needed in order to determine the optimal development scenario.

Production at Fort Berthold increased from 4,000 BOE/day at the start of 2011 to approximately 9,000 BOE/day as we exited the year. Our plans are to grow production to 20,000 to 25,000 BOE/day from this region over the next two to three years.

We plan to spend approximately $300 million in 2012 at Fort Berthold running three to four drilling rigs in the play with the majority of wells expected to be long horizontal wells. Through the latter part of 2011, we experienced an escalation in our drilling and completion costs in large part due to the high activity levels in the region. We are making several changes to our well design and execution procedures and are targeting a long horizontal well cost of approximately $10 million as we exit spring break-up. Despite this cost escalation, with our increased estimate of recoveries, the net present value of a long horizontal well is approximately $15 million. We anticipate rates of return in this region of over 60% based upon current commodity prices.

Crude Oil Waterfloods

We continued to focus our efforts on enhancing the value of our crude oil waterflood portfolio through both drilling activity and enhanced oil recovery techniques. We invested $164 million with approximately 60% directed to drilling and completions and the remainder on plant and facility enhancements to support future activities. We drilled 34.1 net wells with the majority of our drilling in the Ratcliffe, Viking and Cardium plays.

We advanced work on our two enhanced oil recovery projects at Giltedge and Medicine Hat in 2011. To date, production results from the project area are better than anticipated and we expect to expand the polymer flood by adding three injection wells in 2012. Our activities at Medicine Hat included facilities improvements in preparation for polymer injection in the first quarter of 2012. We replaced 100% of production, adding 5.6 MMBOE of 2P reserves, including the conversion of 800,000 BOE of contingent resources associated with our polymer project at Giltedge and 3.4 MMBOE of contingent resources associated with our incremental oil recovery projects. In addition to the 89.9 MMBOE of 2P reserves booked to our waterflood properties at year-end, our internal best estimate of contingent resources (associated with only a portion of our waterflood portfolio) was 56 MMBOE at December 31, 2011. Approximately 34 MMBOE of contingent resources are attributable to the enhanced oil recovery projects at Giltedge and Medicine Hat. As work proceeds and assessed results support the economic viability of these projects, we would expect that contingent resources will be reclassified as reserves.

In 2012, we intend to invest approximately $150 million, or approximately half of the cash flow generated by these properties, to maintain production. We plan to direct $85 million to drilling/completions/injector conversion activities, $58 million on plant/facilities/maintenance, and $7 million on our enhanced oil recovery projects at Giltedge and Medicine Hat. With a low base decline rate of approximately 12%, these properties provide a complement to our new growth properties that have higher initial decline rates.

Marcellus Shale

In 2011, under a strategy of reducing our inventory of non-operated dry gas, we successfully sold approximately 45% of our non-operated acreage position in the Marcellus for $568 million. We realized a net gain of $272 million on the sale and have essentially recovered all of our initial investment in this region while retaining ownership of approximately 110,000 net acres, 60% of which is operated.

Marcellus activities during 2011 were focused on delineation drilling to determine the viability of the Marcellus in new areas, to retain leases and to add production and reserves in developing areas. Approximately $210 million was invested on delineation and development drilling activities (including $36 million that was spent on properties that were part of the disposition) with roughly three quarters of this amount invested with our non-operated partners in the northeast region of Pennsylvania. We drilled a total of 16 net wells (12 non-operated and 4 operated) during the year. However due to delays in pipeline infrastructure, only 5.3 net non-operated wells were brought on-stream in 2011. Despite these delays and the sale of 5.4 MMcfe of production, we were able to increase production by approximately 120% year-over-year and exited 2011 producing approximately 25.2 MMcf/day. Through our successful drilling activities, we added 67.2 Bcf of 2P reserves. Total 2P reserves booked in the Marcellus are now 154 Bcf, up 64% from our 2P reserves booking at December 31, 2010 of 94 Bcf adjusted for the disposition.

An independent best estimate of contingent resources in the Marcellus is 2.3 Tcf of natural gas, essentially unchanged from our 2010 estimate of contingent resources net of the disposition. As a result of the success of our drilling program, our independent reserve evaluators have increased the estimated average EUR per well to 6.6 Bcf from the previous estimate of 5.4 Bcf. We believe that our 2P F&D costs including FDC of $3.84/Mcf are not a true reflection of long-term F&D in this area as almost 50% of the capital spent this year related to wells and facilities which did not come on-stream in 2011 and had no associated reserve bookings at year end. We currently have 13 net producing wells (120 gross wells) and 16 net wells (246 gross wells) waiting on completions and/or tie-in.

We plan to spend approximately $190 million in the Marcellus region in 2012, with approximately 80% allocated to our non-operated interests in the northeast area of Pennsylvania. With the low natural gas price environment, we plan to prudently invest with our partners to retain this valuable acreage. Well results in northeast Pennsylvania have continued to surpass our expectations in terms of both initial production rates and declines. Well costs in this region are currently averaging $7 to $8 million per well. We plan to direct approximately $30 to $40 million to drill appraisal wells on our operated leases in Pennsylvania where we are focused on demonstrating the potential in these areas and retaining our lease interests. In total we expect to participate in drilling approximately 19 net wells in the Marcellus with approximately 18 net wells on-stream in 2012. We expect our total Marcellus production to grow from 25 MMcf/day at the end of 2011 to close to 70 MMcf/day as we exit 2012.

Liquids Rich Natural Gas

In 2011, we spent $91 million on our liquids rich natural gas prospects in Alberta and British Columbia. We continued to delineate our Stacked Mannville position in the Ansell/Minehead/Hanlan areas drilling three Wilrich wells and one Bluesky operated well. As previously mentioned, we added to our Montney land position throughout 2011, acquiring approximately 17,000 net acres in the Cameron area taking our total Montney land position to approximately 33,000 net acres. We drilled our first vertical Montney delineation well at the end of 2011 and expect to complete this well in early 2012. Results from our 2011 drilling activities were positive as we grew production from 13,800 BOE/day to 16,800 BOE/day as we exited the year. In addition, 4.9 MMBOE of 2P reserves (before economic and technical revisions) were added replacing 100% of production.

As a result of continued weak natural gas prices, we plan to take a measured approach to spending in this area in 2012. We expect to invest $80 million on both our operated and non-operated leases. Our operated drilling will target the Stacked Mannville as well as delineation of our Montney and Duvernay acreage positions.

RESERVES AND CONTINGENT RESOURCES

All of our reserves, including our U.S. reserves, were evaluated using Canadian National Instrument 51-101 (“NI 51-101”) standards. Independent reserve evaluations have been conducted on approximately 86% of the total proved plus probable value (discounted at 10%) of our reserves at December 31, 2011. McDaniel & Associates Consultants Ltd. (“McDaniel”) evaluated 86% of our Canadian reserves as well as the reserves associated with our western U.S. assets and reviewed the internal evaluation completed by Enerplus on the remaining portion. The evaluation of contingent resources associated with our leases at Fort Berthold was conducted by Enerplus and audited by McDaniel. Haas Petroleum Engineering Services Inc. (“Haas”) evaluated 100% of our Marcellus shale gas assets in the U.S. and provided both the reserves and contingent resource estimates. The contingent resource assessments associated with our waterflood properties was completed internally by Enerplus.

See “Information Regarding Reserves, Resources and Operational Information” at the end of this news release for information regarding the presentation of company interest reserves and contingent resources.

Reserves & Contingent Resources by Resource Play

Play Types	Proved Reserves	Proved plus Probable Reserves	Proved plus Probable Booked Net Drilling Locations	"Best Estimate" Contingent Resources*	Incremental Future Contingent Resource Net Drilling Locations
Tight Oil (MMBOE)	48.6	84.1	63	49	78
Crude Oil Waterfloods (MMBOE)	69.1	89.9	50	56	TBD
Conventional Oil (MMBOE)	13.7	18.4	12	-	-
Total Oil (MMBOE)	131.4	192.4	125	105	78
Marcellus Shale Gas (Bcf)	92.7	153.5	14	2,279	430
Conventional Gas (Bcfe)	443.2	624.1	134	-	-
Total Gas (Bcfe)	535.8	777.6	148	2,279	430
Total Company (MMBOE)	220.8	321.9	273	485	508

* No contingent resource assessment has been conducted on our tight gas, shallow gas or other conventional oil and gas assets at this time. Only a portion of our crude oil waterflood portfolio has been assessed for contingent resources at this time. Waterflood contingent resources include resources added through enhanced oil recovery and incremental oil recovery activities.
Numbers may not add due to rounding.

Reserves Summary

The following table sets out our company interest, gross and net reserve volumes at December 31, 2011 by production type and reserve category under McDaniel's forecast price scenarios as set forth below in this news release. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit and reserves associated with a property. Company interest reserves consist of gross reserves, which are before the deduction of any royalties, plus Enerplus' royalty interests in reserves.

Reserves Summary	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Company Interest							
Proved Producing	66,595	25,560	92,155	7,854	432,013	43,738	179,300
Proved Developed Non-Producing	2,415	376	2,791	115	9,004	16,317	7,127
Proved Undeveloped	18,350	3,368	21,718	1,246	35,870	32,627	34,380
Total Proved	87,360	29,304	116,664	9,215	476,887	92,682	220,807
Total Probable	44,407	10,090	54,497	4,411	192,363	60,861	101,112
Proved plus Probable	**131,767**	**39,394**	**171,161**	**13,626**	**669,250**	**153,543**	**321,919**
Gross							
Proved Producing	65,817	25,546	91,363	7,717	415,541	43,738	175,627
Proved Developed Non-Producing	2,406	376	2,782	116	8,969	16,317	7,112
Proved Undeveloped	18,345	3,368	21,713	1,224	33,776	32,627	34,004
Total Proved	86,568	29,290	115,858	9,057	458,286	92,682	216,743
Total Probable	44,178	10,086	54,264	4,303	181,185	60,861	98,908
Proved plus Probable	**130,746**	**39,376**	**170,122**	**13,360**	**639,471**	**153,543**	**315,651**
Net							
Proved Producing	57,162	20,962	78,124	5,452	371,957	30,593	150,668
Proved Developed Non-Producing	2,034	326	2,360	90	7,588	13,271	5,925
Proved Undeveloped	14,731	2,695	17,426	978	31,198	26,474	28,016
Total Proved	73,927	23,983	97,910	6,520	410,743	70,338	184,609
Total Probable	36,197	7,995	44,192	3,279	165,476	48,183	83,081
Proved plus Probable	**110,124**	**31,978**	**142,102**	**9,799**	**576,219**	**118,521**	**267,690**

Reserve Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a company interest basis, from December 31, 2010 to December 31, 2011.

Proved Reserves – Company Interest Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2010	49,608	29,177	78,785	8,515	510,049	-	172,308
Acquisitions	125	-	125	-	-	-	125
Dispositions	(779)	-	(779)	(7)	(917)	-	(939)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	3,115	1,080	4,195	332	21,959	-	8,187
Economic Factors	52	28	80	(133)	(16,059)	-	(2,730)
Technical Revisions	(1,706)	2,022	316	234	2,571	-	978
Production	(3,978)	(3,003)	(6,981)	(1,160)	(79,981)	-	(21,471)
Proved Reserves at Dec. 31, 2011	46,437	29,304	75,741	7,781	437,622	-	156,458

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2010	30,921	-	30,921	95	44,041	52,225	47,061
Acquisitions	-	-	-	-	-	-	-
Dispositions	-	-	-	(11)	-	(10,299)	(1,728)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	12,236	-	12,236	668	4,456	55,435	22,886
Economic Factors	-	-	-	-	-	(3,824)	(637)
Technical Revisions	1,801	-	1,801	729	(4,936)	6,507	2,792
Production	(4,035)	-	(4,035)	(47)	(4,296)	(7,362)	(6,025)
Proved Reserves at Dec. 31, 2011	40,923	-	40,923	1,434	39,265	92,682	64,349

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2010	80,529	29,177	109,706	8,610	554,090	52,225	219,369
Acquisitions	125	-	125	-	-	-	125
Dispositions	(779)	-	(779)	(18)	(917)	(10,299)	(2,667)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	15,351	1,080	16,431	1,000	26,415	55,435	31,073
Economic Factors	52	28	80	(133)	(16,059)	(3,824)	(3,367)
Technical Revisions	95	2,022	2,117	963	(2,365)	6,507	3,770
Production	(8,013)	(3,003)	(11,016)	(1,207)	(84,277)	(7,362)	(27,496)
Proved Reserves at Dec. 31, 2011	87,360	29,304	116,664	9,215	476,887	92,682	220,807

Probable Reserves – Company Interest Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2010	14,098	9,783	23,881	2,825	173,983	-	55,703
Acquisitions	34	-	34	-	-	-	34
Dispositions	(331)	-	(331)	(3)	(321)	-	(387)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	1,268	1,050	2,318	175	10,595	-	4,259
Economic Factors	(13)	7	(6)	(140)	(10,294)	-	(1,861)
Technical Revisions	(1,502)	(750)	(2,252)	98	(6,617)	-	(3,257)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2011	13,554	10,090	23,644	2,955	167,346	-	54,491

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2010	16,266	-	16,266	141	24,114	64,437	31,165
Acquisitions	-	-	-	-	-	-	-
Dispositions	-	-	-	(60)	-	(12,693)	(2,175)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	17,319	-	17,319	937	6,302	28,993	24,138
Economic Factors	-	-	-	-	-	(1,819)	(304)
Technical Revisions	(2,732)	-	(2,732)	438	(5,399)	(18,057)	(6,203)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2011	30,853	-	30,853	1,456	25,017	60,861	46,621

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2010	30,364	9,783	40,147	2,966	198,097	64,437	86,868
Acquisitions	34	-	34	-	-	-	34
Dispositions	(331)	-	(331)	(63)	(321)	(12,693)	(2,562)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	18,587	1,050	19,637	1,112	16,897	28,993	28,397
Economic Factors	(13)	7	(6)	(140)	(10,294)	(1,819)	(2,165)
Technical Revisions	(4,234)	(750)	(4,984)	536	(12,016)	(18,057)	(9,460)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2011	44,407	10,090	54,497	4,411	192,363	60,861	101,112

Proved Plus Probable Reserves – Company Interest Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2010	63,706	38,960	102,666	11,340	684,032	-	228,011
Acquisitions	159	-	159	-	-	-	159
Dispositions	(1,110)	-	(1,110)	(10)	(1,238)	-	(1,326)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	4,383	2,130	6,513	507	32,554	-	12,446
Economic Factors	39	35	74	(273)	(26,353)	-	(4,591)
Technical Revisions	(3,208)	1,272	(1,936)	332	(4,046)	-	(2,279)
Production	(3,978)	(3,003)	(6,981)	(1,160)	(79,981)	-	(21,471)
Proved Plus Probable Reserves at Dec. 31, 2011	59,991	39,394	99,385	10,736	604,968	-	210,949

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2010	47,187	-	47,187	236	68,155	116,662	78,226
Acquisitions	-	-	-	-	-	-	-
Dispositions	-	-	-	(71)	-	(22,992)	(3,903)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	29,555	-	29,555	1,605	10,758	84,428	47,024
Economic Factors	-	-	-	-	-	(5,643)	(941)
Technical Revisions	(931)	-	(931)	1,167	(10,335)	(11,550)	(3,411)
Production	(4,035)	-	(4,035)	(47)	(4,296)	(7,362)	(6,025)
Proved Plus Probable Reserves at Dec. 31, 2011	71,776	-	71,776	2,890	64,282	153,543	110,970

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2010	110,893	38,960	149,853	11,576	752,187	116,662	306,237
Acquisitions	159	-	159	-	-	-	159
Dispositions	(1,110)	-	(1,110)	(81)	(1,238)	(22,992)	(5,229)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	33,938	2,130	36,068	2,112	43,312	84,428	59,470
Economic Factors	39	35	74	(273)	(26,353)	(5,643)	(5,532)
Technical Revisions	(4,139)	1,272	(2,867)	1,499	(14,381)	(11,550)	(5,690)
Production	(8,013)	(3,003)	(11,016)	(1,207)	(84,277)	(7,362)	(27,496)
Proved Plus Probable Reserves at Dec. 31, 2011	131,767	39,394	171,161	13,626	669,250	153,543	321,919

NET PRESENT VALUE OF FUTURE PRODUCTION REVENUE

The estimated reserve volumes and net present values of all future net revenues at December 31, 2011 were based upon forecast crude oil and natural gas pricing assumptions prepared by McDaniel as of January 1, 2012. These prices were applied to the reserves evaluated by McDaniel and Haas, along with those evaluated internally by Enerplus and reviewed by McDaniel. The base reference prices and exchange rates used by McDaniel are detailed below:

McDaniel January 2012 Forecast Price Assumptions

	WTI Crude Oil US$/bbl	Light Crude Oil[1] Edmonton CDN$/bbl	Hardisty Heavy Oil 12° API CDN$/bbl	Henry Hub Gas Price US$/MMBtu	Natural Gas 30 day spot @ AECO CDN$/MMBtu	Exchange Rate US$/CDN$
2012	97.50	99.00	74.00	3.75	3.50	0.975
2013	97.50	99.00	74.00	4.50	4.20	0.975
2014	100.00	101.50	75.90	5.05	4.70	0.975
2015	100.80	102.30	76.50	5.50	5.10	0.975
2016	101.70	103.20	77.10	5.95	5.55	0.975
Thereafter	**	**	**	**	**	0.975

(1) Edmonton Light Sweet 40 degree API, 0.5% sulphur content crude

** Escalation varies after 2016

The following table provides an estimate of the net present value of Enerplus' future production revenue after deduction of royalties, estimated future capital and operating expenditures, and before and after income taxes. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves. The after tax net present value of future production revenues reflects the tax burden on properties on a stand-alone basis and does not consider the business-entity level tax situation or any tax planning.

Net Present Value of Future Production Revenue – Forecast Prices and Costs (Before Tax)

Reserves at December 31, 2011, ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	5,958	4,080	3,155	2,606
Proved developed non-producing	232	174	141	118
Proved undeveloped	1,006	623	408	274
Total Proved	7,196	4,877	3,704	2,998
Probable	4,449	2,377	1,550	1,125
Total Proved Plus Probable Reserves	11,645	7,254	5,254	4,123
Total Proved Plus Probable Reserves (after tax)	8,550	5,428	3,994	3,175

NET ASSET VALUE

Enerplus' estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before taxes, as estimated by our independent reserve engineers (McDaniel and Haas) at year-end plus the estimated value of our undeveloped acreage and other equity investments, less decommissioning liabilities , long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserve engineers.

In addition, this calculation ignores "going concern" value and assumes only the reserves identified in the reserve reports with no further acquisitions or incremental development, including development of contingent resources. At December 31, 2011, the estimate of contingent resources contained within our leases was 485 million BOE, more than 1.5 times our proved plus probable reserves. As we execute our capital programs, we expect to convert contingent resources to reserves and significantly increase the value of these assets.

The land values described in the Net Asset Value table below do not necessarily reflect the full value of the contingent resources associated with these lands.

Net Asset Value (Forecast Prices and Costs at December 31, 2011)

($ millions except per share amounts, discounted at)	0%	5%	10%	15%
Total net present value of proved plus probable reserves (before tax)	$11,645	$7,254	$5,254	$4,123
Undeveloped acreage (2011 Year End) (1)				
Canada (845,849 Acres)	224	224	224	224
U.S. West (98,742 Acres)	218	218	218	218
U.S. Marcellus Shale (106,985 Acres)	264	264	264	264
Decommissioning liability (2)	(309)	(155)	(30)	(2)
Long-term debt, including current portion (net of cash)	(901)	(901)	(901)	(901)
Net working capital including deferred financial assets and credits	(349)	(349)	(349)	(349)
Marcellus carry commitment	(37)	(37)	(37)	(37)
Other equity investments (3)	208	208	208	208
Net Asset Value of Assets	**$10,963**	**$6,726**	**$4,851**	**$3,748**
Net Asset Value per Share(4)	**$60.52**	**$37.13**	**$26.78**	**$20.69**

(1) Acreage acquired in 2009, 2010 and 2011 valued at acquisition cost. Acreage acquired prior to 2009 valued at $100/acre.
(2) Decommissioning liability does not equal the amount on the balance sheet ($563.8 million) as the balance sheet amount uses a 2.49% discount rate and a portion of the decommissioning liability costs are already reflected in the estimated net present value of future net revenues from our reserves computed by the independent reserve evaluators.
(3) Other equity investment portfolio is valued at the estimated fair value.
(4) Based on 181,159,000 shares outstanding as at December 31, 2011.

F&D AND FD&A COSTS

F&D and FD&A costs have been calculated both including and excluding future development capital. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year. The significant increase in FDC reported at year-end is primarily related to higher well cost assumptions in both the Fort Berthold and Marcellus regions.

2011 F&D and FD&A Costs

($ millions except for per BOE amounts)	Excluding Future Development Capital	Including Future Development Capital
Proved Plus Probable Reserves		
Finding & Development Costs		
Capital Expenditures (1)	$ 829.8	$ 829.8
Net change in Future Development Capital	-	$ 435.9
Company Interest reserve additions (MMBOE)	48.2	48.2
F&D costs ($/BOE)	$ 17.22	$ 26.26
Finding, Development & Acquisition Costs		
Capital expenditures and net acquisitions	$ 370.2	$ 370.2
Net change in Future Development Capital	-	$ 402.7
Company Interest reserve additions (MMBOE)	43.2	43.2
FD&A costs ($/BOE)	$ 8.57	$ 17.89
Proved Reserves		
Finding & Development Costs		
Capital Expenditures (1)	$ 829.8	$ 829.8
Net change in Future Development Capital	-	$ 230.7
Company Interest reserve additions (MMBOE)	31.5	31.5
F&D costs ($/BOE)	$ 26.34	$ 33.67
Finding, Development & Acquisition Costs		
Capital expenditures and net acquisitions	$ 370.2	$ 370.2
Net change in Future Development Capital	-	$ 213.0
Company Interest reserve additions (MMBOE)	28.9	28.9
FD&A costs ($/BOE)	$ 12.81	$ 20.18

(1) 2011 E&D capital - excludes $35.9 million of spending associated with sold Marcellus properties
(2) Net acquisition capital is exclusive of $109.6 million associated with the Marcellus carry commitment

2012 OUTLOOK

We plan to spend $800 million on exploration and development projects in 2012 delivering annual production growth of over 10%. We are forecasting average production of approximately 83,000 BOE/day during 2012 growing to approximately 88,000 BOE/day as we exit the year. Over 70% of our spending is expected to be focused on oil and liquids rich natural gas projects with 40% of our capital directed to light crude oil development at Fort Berthold, North Dakota. As a result, we expect annual oil production to grow by approximately 7,000 BOE in 2012 and we expect our average crude oil and liquids production will increase from 45% of total production to approximately 50% in 2012. We expect production will grow throughout 2012 ranging from approximately 77,200 BOE/day in the last quarter of 2011to 88,000 BOE/day as we exit 2012.

Based upon current forward commodity prices, we expect cash flow to increase in 2012 as a result of the growth in our total production volumes and in particular, the expected increase in crude oil and liquids volumes.

We plan to minimize spending on our operated dry gas projects given the current outlook for natural gas prices. We intend to continue to invest alongside our partners in the Marcellus as they drill to delineate and retain leases and have allocated approximately $190 million on both our operated and non-operated leases. We expect production to grow from 25 MMcf/day currently to close to 70 MMcf/day as we exit 2012. Canadian conventional dry gas production is expected to decline throughout the year with Marcellus gas production increasing to represent approximately 30% of our total corporate natural gas volumes by year-end. Although natural gas prices are under pressure today, the Marcellus continues to be one of the lowest cost dry gas developments in North America and we believe this asset will play an important part in our future growth strategy.

Through a disciplined exploration program, we plan to invest close to $100 million to unlock the value in our undeveloped land base in the Duvernay, Montney, and Cardium plays and in our operated acreage in the Marcellus as well as advancing our enhanced oil recovery projects. This spending is not expected to contribute significant new production in 2012 although we expect it will set the stage for future production and reserve additions.

Despite anticipated cash flow growth in 2012 as a result of increases in production, we anticipate our capital spending and dividends will exceed cash flow. We plan to fund the shortfall through debt financing, the proceeds of our recent $345 million equity financing and expected proceeds from an expanded dividend reinvestment plan. In addition, we continue to hold a portfolio of equity investments that we may sell to help fund capital spending or acquisitions. As always, we will continue to evaluate dividend levels with respect to cash flow, debt levels, capital spending, commodity prices and market conditions.

Summary 2012 Guidance	**Target**
Average annual production:	
Crude Oil (bbls/day)	37,200
Natural Gas Liquids (bbls/day)	3,800
Natural Gas (Mcf/day)	252,000
Total	83,000 BOE/day
Exit rate 2012 production:	
Crude Oil (bbls/day)	40,500
Natural Gas Liquids (bbls/day)	4,100
Natural Gas (Mcf/day)	260,000
Total	88,000 BOE/day
2012 production mix	50% oil & NGLs, 50% gas
Development capital:	
Development Drilling & Completions	$600 million
Plant/Facilities	$70 million
Maintenance	$30 million
Exploration & Seismic	$100 million
Total	$800 million
Planned Drilling Activity	108 net wells
Planned On-streams	95 net wells
Acquisitions:	
Marcellus carry commitment	$37 million
Undeveloped land & lease extensions	$40 million

Average royalty rate	21%
Operating costs	$10.40/BOE
G&A costs	$3.55/BOE
Average interest and financing costs	6%

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

INFORMATION REGARDING RESERVES, RESOURCES AND OPERATIONAL INFORMATION

Currency

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

Barrels of Oil Equivalent and Cubic Feet of Gas Equivalent

This news release also contains references to "BOE" (barrels of oil equivalent), "Mcfe" (thousand cubic feet of gas equivalent), "Bcfe" (billion cubic feet of gas equivalent) and "Tcfe" (trillion 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, Bcfes and Tcfes. BOEs, Mcfes, Bcfes and Tcfes 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

*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 National Instrument 51-101 adopted by the Canadian securities regulators ("**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, 2011, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, will be contained within our Annual Information Form for the year ended December 31, 2011 ("**our AIF**") which will be available in mid-March 2012 on our website at www.enerplus.com and under our SEDAR profile at www.sedar.com. Additionally, the Annual Information Form will form part of our Form 40-F that will be filed with the U.S. Securities and Exchange Commission and will 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 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, 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. 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. All of our contingent resource estimates are economic using established technologies and under current commodity price assumptions used by our independent reserve evaluators. 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, 2011. 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 assets, our North Dakota Bakken properties and our crude oil waterflood properties as reserves and the positive and negative factors relevant to the "contingent resource" estimates, see our Annual Information Form for the year ended December 31, 2010 (and corresponding Form 40-F) dated March 11, 2011, a copy of which is available under our SEDAR profile at www.sedar.com and a copy of the Form 40-F which is available under our EDGAR profile at www.sec.gov.

F&D and FD&A Costs

F&D costs presented in this news release are calculated (i) in the case of F&D costs for proved reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves in the year, and (ii) in the case of F&D costs for proved plus probable reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to its reserves additions for that year.

FD&A costs presented in this news release are calculated (i) in the case of FD&A costs for proved reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves including net acquisitions in the year, and (ii) in the case of FD&A costs for proved plus probable reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves including net acquisitions in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding, development and acquisition costs related to its reserves additions for that year.

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, whereas Canadian issuers may disclose oil and gas resources. Resources are different than, and should not 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' strategy to deliver both income and growth to investors and Enerplus' related asset portfolio; future returns to shareholders from both dividends and from growth in per share production and reserves; future capital and development expenditures and the allocation thereof among our resource plays and 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; the volume and product mix of Enerplus' oil and gas production; securing necessary infrastructure and third party services; the amount of future asset retirement obligations; future cash flows and debt-to-cash flow levels; potential asset sales; returns 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 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, 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 and 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 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 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, and the terms "F&D costs" and "FD&A costs" as measures of operating performance. We calculate funds flow based on cash flow from operating activities before changes in non-cash operating working capital and decommissioning expenditures, all of which are measures prescribed by Canadian generally accepted accounting principles ("GAAP") which were revised effective January 1, 2011 to converge with 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 cash dividends to shareholders plus development capital and office expenditures, divided by funds flow from operating activities.

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