Management's Discussion and Analysis ("MD&A")

The following discussion and analysis of financial results is dated November 8, 2012 and is to be read in conjunction with:

- the audited consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the years ended December 31, 2011 and 2010; and
- the unaudited interim Consolidated Financial Statements of Enerplus as at and for the three and nine months ended September 30, 2012 and 2011, the "Interim Financial Statements".

All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Interim Financial Statements. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. All production volumes are presented on a company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities and may not be comparable to information produced by other entities.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information.

NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by IFRS and therefore may not be comparable with the calculation of similar measures by other entities:

"Payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing cash dividends to shareholders by funds flow.

"Adjusted payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate our adjusted payout ratio as cash dividends to shareholders plus capital spending (including office capital) divided by funds flow.

"Netback" is used to evaluate operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and gas sales revenue (net of transportation), less royalties and operating costs.

OVERVIEW

Our production averaged 81,573 BOE/day in the third quarter representing an increase of 11% over the previous year. Our crude oil and natural gas liquids production also increased approximately 24% over the previous year mainly due to our capital program at our Fort Berthold crude oil property. However our natural gas production is lower than we expected due to tie-in delays on our non-operated Marcellus properties and as a result we are reducing our annual average production guidance to 82,000 BOE/day from 83,500 BOE/day and adjusting our exit rate production guidance to a range of 85,000 BOE/day to 88,000 BOE/day. Given current low natural gas prices these tie-in delays are not expected to materially impact our cash flow in 2012.

Capital spending was in-line with expectations totaling $167.0 million for the third quarter and $692.7 million year-to-date. We continue to manage towards annual capital spending of $850 million. During the quarter we also spent $4.6 million on our Marcellus carry commitment which is now fully satisfied.

Funds flow for the quarter increased by 9% to $135.0 million from $123.3 million in the same quarter of 2011 driven by increased oil revenues along with a decrease in current taxes. G&A and equity based compensation expenses were $3.15/BOE for the quarter and are on track with annual guidance of $3.30/BOE. Operating costs increased to $12.59/BOE for the quarter mainly due to seasonal and non-recurring costs along with mark-to-market losses on our electricity contracts. Although our absolute operating costs are on target with our expectations for the year, we are increasing our annual guidance to $10.70/BOE from $10.40/BOE due to our revised production guidance.

We recorded a net loss of $63.5 million for the quarter as we experienced a non-cash mark-to-market loss of $48.7 million on our commodity hedging contracts due to the improvement in crude oil prices during the quarter. We also recorded non-cash impairments of $113.8 million on our Exploration and Evaluation ("E&E") assets resulting from acreage we intend to let expire.

We have improved our balance sheet and liquidity during the quarter with the sale of our equity interest in Laricina Energy for after tax proceeds of approximately $141.0 million. In addition, subsequent to the quarter we announced an agreement to sell all of our non-core assets in Manitoba for gross proceeds of approximately $220 million and we extended our $1.0 billion credit facility by a year to October 31, 2015 with the same commercial terms and pricing.

RESULTS OF OPERATIONS

Production

Production in the third quarter of 2012 was 81,573 BOE/day, slightly down from our second quarter production of 82,108 BOE/day. Our crude oil production is in-line with expectations however our natural gas production was lower than anticipated as tie-in activity on our non-operated interests in the Marcellus has been slower than expected. Although the growth in production volumes has been delayed, the cash flow impact for 2012 is modest given the current low natural gas price environment. We continue to expect a slower pace of on-streams for the remainder of 2012 and anticipate exit production to be 10 MMcf/day to 20 MMcf/day lower than originally planned.

Compared to the third quarter of 2011, production increased 11% or 8,328 BOE/day with the majority coming from our crude oil property in Fort Berthold. Our natural gas volumes were relatively flat year over year as increased volumes from our Marcellus assets offset expected production declines on our conventional natural gas assets in Canada.

Our weighting of crude oil and liquids production was 49% in the third quarter, up from 45% in the third quarter of 2011. We continue to expect a crude oil and liquids weighting of approximately 50% as we exit 2012.

Average daily production volumes for the three and nine months ended September 30, 2012 and 2011 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2012**	**2011**	**% Change**	**2012**	**2011**	**% Change**
Crude oil (bbls/day)	36,810	29,337	25%	35,807	29,665	21%
Natural gas liquids (bbls/day)	3,538	3,295	7%	3,644	3,323	10%
Natural gas (Mcf/day)	247,347	243,675	2%	249,046	250,244	–%
Total daily sales (BOE/day)	81,573	73,245	11%	80,959	74,695	8%

We are reducing our annual average production guidance to 82,000 BOE/day from 83,500 BOE/day and adjusting our exit rate guidance to a range of 85,000 BOE/day to 88,000 BOE/day given the tie-in delays we are experiencing in the Marcellus. It is important to note this reduction is due to lower natural gas production estimates and we are not changing our forecasts with respect to crude oil and natural gas liquids production. Our 2012 guidance has not been adjusted for the Manitoba disposition as it is expected to close near the end of 2012. Our guidance does not contemplate any further acquisition or disposition of producing assets.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, funds flow and financial condition. The following table compares our average selling prices for the three and nine months ended September 30, 2012 and 2011. It also compares the benchmark price indices for the same periods.

	Three months ended September 30,			Nine months ended September 30,		
Average Selling Price[1]	**2012**	**2011**	**% Change**	**2012**	**2011**	**% Change**
Crude oil (per bbl)	$ 76.41	$ 77.57	(1)%	$ 78.72	$ 82.01	(4)%
Natural gas liquids (per bbl)	47.81	64.98	(26)%	54.88	63.89	(14)%
Natural gas (per Mcf)	2.20	3.73	(41)%	2.18	3.83	(43)%
Per BOE	43.30	46.44	(7)%	44.10	48.35	(9)%

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

	Three months ended September 30,			Nine months ended September 30,		
Average Benchmark Pricing	**2012**	**2011**	**% Change**	**2012**	**2011**	**% Change**
WTI crude oil (US$/bbl)	$ 92.22	$ 89.76	3%	$ 96.21	$ 95.48	1%
WTI crude oil CDN$ equivalent (CDN$/bbl)	92.22	87.97	5%	96.21	93.57	3%
AECO natural gas – monthly index (CDN$/Mcf)	2.19	3.72	(41)%	2.18	3.74	(42)%
AECO natural gas – daily index (CDN$/Mcf)	2.29	3.66	(37)%	2.11	3.77	(44)%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	2.81	4.19	(33)%	2.62	4.23	(38)%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	2.81	4.11	(32)%	2.62	4.15	(37)%
USD/CDN exchange rate	1.00	0.98	2%	1.00	0.98	2%

	Nine months ended September 30,								
Average Differentials (US$/bbl or US$/Mcf)	**2012**	**2011**	**Q3 2012**	**Q2 2012**	**Q1 2012**	**Q4 2011**	**Q3 2011**	**Q2 2011**	**Q1 2011**
MSW Edmonton – WTI	$ (9.27)	$ 1.29	$ (7.21)	$ (10.12)	$ (10.49)	$ 1.43	$ 4.21	$ 4.35	$ (4.69)
WCS Hardisty – WTI	(22.00)	(19.37)	(21.72)	(22.87)	(21.42)	(10.48)	(17.62)	(17.64)	(22.86)
Brent Futures (ICE) – WTI	16.00	16.01	17.22	15.38	15.40	14.88	22.35	14.61	11.06
AECO monthly – NYMEX	(0.41)	(0.38)	(0.60)	(0.40)	(0.23)	(0.16)	(0.39)	(0.45)	(0.28)

CRUDE OIL AND NATURAL GAS LIQUIDS

West Texas Intermediate ("WTI") crude oil prices recovered during the third quarter of 2012 after pulling back during the second quarter due to macroeconomic uncertainty. Refinery demand picked up considerably due to seasonal demand factors and lower available capacity. The pricing of WTI remained discounted relative to Brent. Canadian and U.S. Bakken light sweet differentials remain fairly wide, however they are starting to narrow as the industry adds more rail capacity to the region.

The average price received for our crude oil (net of transportation) in the third quarter of 2012 decreased slightly to $76.41/bbl from $77.57/bbl in the third quarter of 2011. For the nine months ended September 30, 2012 our realized crude oil price (net of transportation costs) decreased 4% to $78.72/bbl from $82.01/bbl during the same period in 2011. Differentials for both light sweet and heavy crude oil production, both in Canada and the U.S., have been significantly wider in 2012 compared to 2011, due to a combination of increased supply and numerous pipeline and refinery issues. The wider differentials have led to lower realized prices relative to benchmark WTI pricing in both the three and nine month periods in 2012.

Our realized price for natural gas liquids decreased by 26% to $47.81/bbl from $64.98/bbl in the third quarter compared to the same quarter of 2011. Year-to-date our natural gas liquids realized $54.88/bbl, a decrease of 14% compared to $63.89/bbl in the previous year. The decreases reflect an excess supply of propane and butane in the market in 2012 which represents approximately 65% of our natural gas liquids production.

NATURAL GAS

Natural gas prices remained weak during the third quarter of 2012 although we did see some price recovery near the end of the quarter as we head into fall and winter. The year-over-year storage surplus has been drastically reduced throughout the summer due to increased demand for power generation along with warmer than normal summer temperatures. Storage will likely finish the injection season at record levels but is no longer at risk of encountering widespread congestion issues. U.S. gas drilling rig counts are down over 50% from 2011 due to challenging dry gas economics which is helping to level off U.S. natural gas production after many years of growth. Our outlook is for a more balanced market in 2013 after being oversupplied during 2012.

For the three months ended September 30, 2012 we sold our natural gas for an average price of $2.20/Mcf (net of transportation costs) which represented a 41% decline from the prices received during the same period of 2011. This decrease was in line with the decrease in the monthly AECO index but was larger than the change in both the AECO daily and NYMEX indices. Our lower realized prices include losses associated with physical fixed price positions that we took at the beginning of the summer gas season.

For the nine months ended September 30, 2012 our average realized natural gas price was $2.18/Mcf (net of transportation costs), a 43% decrease from $3.83/Mcf during the same period in 2011. This decrease was in line with the changes in the AECO indices.

Price Risk Management

We have a price risk management program that considers our overall financial position, the economics of our capital program and potential acquisitions. Consideration is also given to the cost of our risk management program as we seek to limit our exposure to price downturns. See Note 14 for further information regarding our current price risk management positions.

We have continued to add crude oil and natural gas hedge positions for 2013. As of October 25, 2012 we have swapped 17,000 bbls/day at US$100.84/bbl, which represents approximately 58% of our forecasted net oil production after royalties for 2013. On our natural gas production we have floor protection on 32,200 Mcf/day at $3.31/Mcf before premiums, representing approximately 17% of our forecasted natural gas production after royalties for 2013. In addition, we have fixed price physical natural gas contracts that are listed in Note 14.

The following is a summary of our financial contracts in place at October 25, 2012 expressed as a percentage of our anticipated net production volumes:

	Crude Oil (US$/bbl)[(1)(2)]		Natural Gas[(1)] (CDN$/Mcf)
	October 1, 2012 – December 31, 2012	January 1, 2013 – December 31, 2013	January 1, 2013 – December 31, 2013
Purchased Puts (floor prices)	$ 103.00	–	$ 3.17
%	3%	–	12%
Sold Puts (limiting downside protection)	$ 65.00	$ 63.33	–
%	7%	15%	–
Swaps (fixed price)	$ 95.83	$ 100.84	$ 3.65
%	60%	58%	5%
Sold Calls (capped price)	$ 133.00	$ 130.00	–
%	3%	12%	–
Purchased Calls (repurchasing upside)	$ 103.00	$ 104.09	–
%	3%	12%	–
Brent – WTI Spread	$ 13.71	–	–
%	10%	–	–

(1) Based on weighted average price (before premiums), estimated average annual production of 82,000 BOE/day for 2012 and 2013, less royalties of 21%.

(2) The majority of our crude oil positions are priced in relation to WTI.

ACCOUNTING FOR PRICE RISK MANAGEMENT

During the third quarter of 2012 we recorded cash gains of $7.9 million on our crude oil contracts. In comparison, during the third quarter of 2011 we realized cash losses of $4.5 million on crude oil contracts. The cash gains in 2012 were due to contracts which provided floor protection above market prices. The cash losses in 2011 were a result of crude oil prices rising above our fixed price swap positions.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. During the third quarter of 2012 forecast crude oil prices increased which resulted in the fair value of our oil contracts decreasing to $53.7 million at September 30, 2012. The change in the fair value of our commodity contracts for the three and nine months ended September 30, 2012 represented an unrealized loss of $48.7 million and an unrealized gain of $71.9 million, respectively. See Note 14 for details.

The following table summarizes the effects of our risk management gains and losses:

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	**Three months ended September 30, 2012**				**Three months ended September 30, 2011**			
Cash gains/(losses):								
Crude Oil	$	7.9	$	2.34/bbl	$	(4.5)	$	(1.67)/bbl
Natural Gas		–	$	– /Mcf		–	$	– /Mcf
Total cash gains/(losses)	$	7.9	$	1.06/BOE	$	(4.5)	$	(0.67)/BOE
Non-cash gains/(losses) on financial contracts:								
Change in fair value – crude oil	$	(47.3)	$	(13.98)/bbl	$	121.6	$	45.05/bbl
Change in fair value – natural gas		(1.4)	$	(0.06)/Mcf		–	$	– /Mcf
Total non-cash gains/(losses)	$	(48.7)	$	(6.49)/BOE	$	121.6	$	18.05/BOE
Total gains/(losses)	$	(40.8)	$	(5.43)/BOE	$	117.1	$	17.38/BOE

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	**Nine months ended September 30, 2012**				**Nine months ended September 30, 2011**			
Cash gains/(losses):								
Crude Oil	$	2.3	$	0.23/bbl	$	(35.5)	$	(4.38)/bbl
Natural Gas		–	$	– /Mcf		13.3	$	0.19/Mcf
Total cash gains/(losses)	$	2.3	$	0.11/BOE	$	(22.2)	$	(1.09)/BOE
Non-cash gains/(losses) on financial contracts:								
Change in fair value – crude oil	$	73.3	$	7.47/bbl	$	127.6	$	15.76/bbl
Change in fair value – natural gas		(1.4)	$	(0.02)/Mcf		(12.6)	$	(0.18)/Mcf
Total non-cash gains/(losses)	$	71.9	$	3.24/BOE	$	115.0	$	5.64/BOE
Total gains/(losses)	$	74.2	$	3.35/BOE	$	92.8	$	4.55/BOE

Revenues

Crude oil and natural gas revenues for the third quarter of 2012 were $324.9 million ($331.7 million, net of $6.8 million of transportation costs), an increase of $12.0 million compared to $312.9 million ($317.7 million, net of $4.8 million of transportation costs) for the third quarter of 2011. Crude oil and natural gas revenues for the nine months ended September 30, 2012 were $978.3 million ($998.1 million, net of $19.8 million of transportation costs), a decrease of $7.5 million compared to $985.8 million ($1,001.2 million, net of $15.4 million of transportation costs) for the same period in 2011. Our crude oil revenues have increased due to higher production levels partially offset by lower realized prices. Natural gas and natural gas liquids revenues have decreased primarily as a result of lower realized prices.

Analysis of Sales Revenue[1] ($ millions)	**Crude oil**	**NGLs**	**Natural Gas**	**Total**
Three months ended September 30, 2011	$ 209.2	$ 19.7	$ 84.0	$ 312.9
Price variance	(3.9)	(5.6)	(34.7)	(44.2)
Volume variance	53.4	1.5	1.3	56.2
Three months ended September 30, 2012	$ 258.7	$ 15.6	$ 50.6	$ 324.9

($ millions)	**Crude oil**	**NGLs**	**Natural Gas**	**Total**
Nine months ended September 30, 2011	$ 664.1	$ 57.9	$ 263.8	$ 985.8
Price variance	(32.3)	(8.9)	(112.3)	(153.5)
Volume variance	140.5	5.8	(0.3)	146.0
Nine months ended September 30, 2012	$ 772.3	$ 54.8	$ 151.2	$ 978.3

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

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three and nine months ended September 30, 2012 royalties were $64.6 million and $193.8 million respectively, compared to $56.1 million and $176.9 million for the same periods of 2011. As a percentage of oil and gas sales, net of transportation costs, royalties were 20% for the three and nine months ended September 30, 2012 compared to 18% in the same periods in 2011. The royalty rate increase is primarily due to an increased proportion of U.S. production where royalty rates are generally higher than those on our Canadian production. We continue to expect an average royalty rate of approximately 21% in 2012.

Operating Expenses

Our operating expenses were $94.5 million for the third quarter of 2012, an increase of $14.0 million from the second quarter of 2012. The third quarter included approximately $10.8 million of charges that we consider to be seasonal or non-routine in nature. These include a newly enacted annual State impact fee on our Pennsylvania wells, one-time charges for upgrading U.S. Bakken facilities for emissions control, costs for a pipeline repair at our Giltedge property, non-operated equalization charges related to prior years, annual property tax payments and non-cash mark-to-market losses on our electricity contracts. As a result we expect operating costs to moderate from these levels during the fourth quarter.

Operating expenses were $94.5 million or $12.59/BOE for the third quarter of 2012 and $247.1 million or $11.14/BOE for the nine months ended September 30, 2012. In comparison, we had operating costs of $73.6 million ($10.92/BOE) and $198.2 million ($9.72/BOE) for the same periods during 2011. We have had higher well servicing and repairs and maintenance costs in the first nine months of 2012 compared to the same period in 2011 when weather delayed similar work until the fourth quarter of 2011. Our 2012 operating costs also include non-cash mark-to-market losses on our electricity contracts of $3.2 million compared to gains of $3.1 million in 2011 which contributed to the year over year change.

Although our aggregate operating costs are still on target for the year, we are increasing our per BOE annual guidance to $10.70/BOE from $10.40/BOE due to our revised production guidance.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three and nine months ended September 30, 2012 and 2011. The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section.

	Three months ended September 30, 2012		
	Crude Oil	Natural Gas	Total
Average daily production	40,561 BOE/day	246,069 Mcfe/day	81,573 BOE/day
Netback[(1)]	(per BOE)	(per Mcfe)	(per BOE)
Revenue[(2)]	$ 70.22	$ 2.78	$ 43.30
Royalties	(15.72)	(0.26)	(8.61)
Cash operating costs	(13.78)	(1.81)	(12.32)
Netback before hedging	$ 40.72	$ 0.71	$ 22.37
Cash hedging gains/(losses)	2.12	–	1.06
Netback after hedging	$ 42.84	$ 0.71	$ 23.43
Netback before hedging ($ millions)	$ 152.0	$ 15.8	$ 167.8
Netback after hedging ($ millions)	$ 159.9	$ 15.8	$ 175.7

	Three months ended September 30, 2011		
	Crude Oil	Natural Gas	Total
Average daily production	32,711 BOE/day	243,202 Mcfe/day	73,245 BOE/day
Netback[(1)]	(per BOE)	(per Mcfe)	(per BOE)
Revenue[(2)]	$ 71.38	$ 4.39	$ 46.44
Royalties	(15.32)	(0.45)	(8.33)
Cash operating costs	(12.06)	(1.66)	(10.90)
Netback before hedging	$ 44.00	$ 2.28	$ 27.21
Cash hedging gains/(losses)	(1.49)	–	(0.66)
Netback after hedging	$ 42.51	$ 2.28	$ 26.55
Netback before hedging ($ millions)	$ 132.4	$ 51.0	$ 183.4
Netback after hedging ($ millions)	$ 127.9	$ 51.0	$ 178.9

(1) See "Non-GAAP Measures" in this MD&A.
(2) Net of oil and gas transportation costs.

	Nine months ended September 30, 2012		
	Crude Oil	Natural Gas	Total
Average daily production	39,026 BOE/day	251,600 Mcfe/day	80,959 BOE/day
Netback[(1)]	(per BOE)	(per Mcfe)	(per BOE)
Revenue[(2)]	$ 72.31	$ 2.98	$ 44.10
Royalties	(15.84)	(0.35)	(8.74)
Cash operating costs	(12.28)	(1.63)	(11.00)
Netback before hedging	$ 44.19	$ 1.00	$ 24.36
Cash hedging gains/(losses)	0.22	–	0.11
Netback after hedging	$ 44.41	$ 1.00	$ 24.47
Netback before hedging ($ millions)	$ 472.5	$ 68.1	$ 540.6
Netback after hedging ($ millions)	$ 474.8	$ 68.1	$ 542.9

	Nine months ended September 30, 2011		
	Crude Oil	Natural Gas	Total
Average daily production	32,745 BOE/day	251,702 Mcfe/day	74,695 BOE/day
Netback[1]	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 75.77	$ 4.49	$ 48.34
Royalties	(15.61)	(0.54)	(8.67)
Cash operating costs	(11.16)	(1.47)	(9.87)
Netback before hedging	$ 49.00	$ 2.48	$ 29.80
Cash hedging gains/(losses)	(3.97)	0.19	(1.09)
Netback after hedging	$ 45.03	$ 2.67	$ 28.71
Netback before hedging ($ millions)	$ 437.6	$ 170.0	$ 607.6
Netback after hedging ($ millions)	$ 402.1	$ 183.3	$ 585.4

(1) See "Non-GAAP Measures" in this MD&A.
(2) Net of oil and gas transportation costs.

Our crude oil properties accounted for 87% of our corporate netback before hedging for the first nine months of 2012 compared to 72% for the same period in 2011. Crude oil netbacks per BOE for the three and nine months ended September 30, 2012 are similar to 2011 as cash hedging gains were sufficient to offset lower realized crude oil prices and higher operating costs. Natural gas netbacks per Mcfe have decreased for the same periods due to lower realized natural gas prices and lower hedging gains.

General and Administrative ("G&A") and Equity Based Compensation Expenses

G&A expenses during the third quarter of 2012 were $18.6 million or $2.48/BOE compared to $15.3 million or $2.27/BOE in the third quarter of 2011. G&A expenses for the nine months ended September 30, 2012 were $59.9 million or $2.70/BOE compared to $49.6 million or $2.43/BOE for the same period during 2011. G&A expenses have increased during 2012 primarily due to expanding our U.S. operations as well as higher professional and legal fees in 2012.

Equity based compensation expense includes charges related to our long-term incentive plans ("LTI plans") and our stock option plan (see Note 13 for further details). The costs of our LTI plans can fluctuate from period to period as they are dependent on our share price. Our LTI costs were higher in the third quarter of 2012 as our share price increased 25% during the quarter compared to a 15% decrease in our share price during the third quarter of 2011.

We also recorded unrealized gains of $2.7 million and $3.1 million for the three and nine months ended September 30, 2012, respectively, related to the equity swap on our LTI plans that we entered into during the second quarter of 2012.

The following table summarizes our G&A and equity based compensation expenses:

	Three months ended September 30,		Nine months ended September 30,	
G&A and Equity Based Compensation Expenses ($ millions)	**2012**	**2011**	**2012**	**2011**
G&A	$ 18.6	$ 15.3	$ 59.9	$ 49.6
Equity based compensation:				
LTI plans expense/(recovery) – cash	5.2	1.2	5.4	10.8
LTI plans equity swap loss/(gain) – non-cash	(2.7)	–	(3.1)	–
Stock option plan – non-cash	2.6	2.8	7.7	9.6
	5.1	4.0	10.0	20.4
Total G&A and Equity Based Compensation Expenses	$ 23.7	$ 19.3	$ 69.9	70.0

(Per BOE)	Three months ended September 30, 2012	2011	Nine months ended September 30, 2012	2011
G&A	$ 2.48	$ 2.27	$ 2.70	$ 2.43
Equity based compensation:				
LTI plans expense/(recovery) – cash	0.69	0.18	0.24	0.53
LTI plans equity swap loss/(gain) – non-cash	(0.37)	–	(0.14)	–
Stock option plan – non-cash	0.35	0.42	0.35	0.47
	0.67	0.60	0.45	1.00
Total G&A and Equity Based Compensation Expenses	$ 3.15	$ 2.87	$ 3.15	$ 3.43

We are maintaining our annual guidance for G&A and equity based compensation expenses at $3.30/BOE.

Finance Expense

Interest on our senior notes and bank credit facility for the three and nine months ended September 30, 2012 totaled $14.9 million and $39.1 million respectively, compared to $10.7 million and $35.3 million for the same periods in 2011. Our interest expense has increased in 2012 as a result of higher debt levels.

Non-cash amounts recorded in finance expense include accretion of decommissioning liabilities, amortization of financing fees and premiums, and unrealized gains and losses resulting from the change in fair value of our interest rate swaps and the interest component on our cross currency interest rate swap ("CCIRS"). See Note 10 for further details.

The following table summarizes the cash and non-cash finance expense:

Finance Expense ($ millions)	Three months ended September 30, 2012	2011	Nine months ended September 30, 2012	2011
Interest on senior notes and bank credit facility	$ 14.9	$ 10.7	$ 39.1	$ 35.3
Non-cash finance expense	4.0	0.1	13.0	7.3
Total Finance Expense	$ 18.9	$ 10.8	$ 52.1	$ 42.6

At September 30, 2012, after including our underlying derivatives, approximately 68% of our debt was based on fixed interest rates while 32% had floating interest rates. In comparison, at September 30, 2011 approximately 55% of our debt was based on fixed interest rates and 45% was floating.

Foreign Exchange

For the three and nine months ended September 30, 2012 we recorded foreign exchange gains of $13.6 million and $18.9 million respectively, compared to foreign exchange losses of $6.2 million and $3.3 million in the same periods in 2011. The majority of our 2012 year-to-date foreign exchange relates to our second quarter CCIRS settlement on our US$175 million senior notes. Upon settlement of the swap we realized a loss of $18.0 million. In addition, we reversed the unrealized loss we had previously recognized which effectively resulted in an unrealized gain of $18.0 million. Unrealized gains or losses also result from the period end revaluation of our U.S. dollar denominated debt. At September 30, 2012 the U.S. dollar weakened relative to both the beginning of the year and the quarter which also contributed to our unrealized gains. See Note 11 for details.

Foreign Exchange ($ millions)	Three months ended September 30, 2012	2011	Nine months ended September 30, 2012	2011
Realized loss/(gain)	$ 4.1	$ (3.9)	$ 10.0	$ 16.4
Unrealized loss/(gain)	(17.7)	10.1	(28.9)	(13.1)
Total Foreign Exchange loss/(gain)	$ (13.6)	$ 6.2	$ (18.9)	$ 3.3

Capital Investment

Capital spending for the third quarter of 2012 totaled $167.0 million compared to $201.3 million for the same period in 2011. During the quarter we continued to focus on our core assets spending $93.1 million on our Fort Berthold crude oil property, $30.3 million on our Marcellus assets and $25.3 million on our crude oil waterflood properties in Canada.

Property and land acquisitions for the three and nine months ended September 30, 2012 totaled $7.3 million and $63.9 million, respectively, compared to $67.3 million and $209.9 million for the same periods in 2011. During the third quarter we spent $2.7 million primarily on additional lands in Fort Berthold along with $4.6 million on our Marcellus carry obligation ($37.0 million year-to-date) which fully satisfied our carry commitment. During the third quarter of 2011 property and land acquisitions included undeveloped land acquisitions in Canada of $31.5 million, $5.6 million on additional undeveloped lands in the Marcellus area and US$30.3 million on our Marcellus carry obligation.

Our total capital investment activity for the three and nine months ended September 30, 2012 and 2011 are outlined below:

Capital Investment ($ millions)	**Three months ended September 30,** 2012	2011	**Nine months ended September 30,** 2012	2011
Capital Spending	$ 167.0	$ 201.3	$ 692.7	$ 520.9
Office Capital	2.7	3.3	8.8	8.3
Sub-total	169.7	204.6	701.5	529.2
Property and Land Acquisitions	7.3	67.3	63.9	209.9
Property Dispositions	(3.1)	(7.3)	(55.6)	(638.1)
Sub-total	4.2	60.0	8.3	(428.2)
Total Net Capital Investment	$ 173.9	$ 264.6	$ 709.8	$ 101.0

We continue to manage towards our annual capital spending guidance of $850 million.

Depletion, Depreciation and Amortization ("DD&A")

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved plus probable reserves. For the three months ended September 30, 2012 DD&A increased to $132.8 million or $17.69/BOE compared to $108.9 million or $16.16/BOE during the same period in 2011. For the nine months ended September 30, 2012 DD&A increased to $379.5 million or $17.11/BOE from $312.5 million or $15.32/BOE during the same period in 2011. The rise in DD&A for the three and nine months ended September 30, 2012 is primarily due to higher production and well costs with respect to our U.S. operations resulting in higher depletion per BOE.

Impairments

We perform impairment tests on our Developed and Producing ("D&P") assets when indicators of impairment are present. Impairment tests are completed on our Cash Generating Units ("CGUs") to determine if their asset carrying values, including goodwill, are impaired. Our impairment test compares the CGU recoverable amount, which is estimated using proved plus probable reserves discounted at 10%, to the CGU carrying value. Calculated impairments are initially allocated to any goodwill carried by the CGU with the remainder recorded against its carrying value. In the third quarter of 2012 we did not record any additional D&P impairments beyond the $86.9 million recorded in the first quarter of 2012 in our Canadian natural gas CGUs which resulted from lower forecast natural gas prices.

Exploration and Evaluation ("E&E") assets are also tested for impairment when there are indicators that suggest their carrying values may exceed their recoverable amount. In the third quarter of 2012 we recorded E&E impairments totaling $113.8 million of which $65.9 million related to Marcellus leases in West Virginia and Maryland representing approximately 40,000 net acres that are set to expire over the next 12 months. We consider these leases to be less prospective than our other Marcellus acreage and we do not plan to further develop or extend the lands given our current outlook for natural gas prices and other opportunities in our portfolio. We also recorded impairments of $47.9 million on our Canadian E&E assets that primarily relate to Saskatchewan Bakken and Deep Gas assets.

Other Assets

Other assets consist of our portfolio of equity investments in other oil and gas companies. During the quarter we sold our shares in Laricina Energy Ltd., which represented the majority of our portfolio, for proceeds of approximately $141.0 million (net of transaction costs) resulting in an economic gain of $86.5 million. For accounting purposes we recognized $38.7 million of this gain upon transition to IFRS when our equity investments were written up to fair value and the remaining $47.8 million of the gain was recorded in net income during this quarter.

Decommissioning Liabilities

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total decommissioning liabilities included on our balance sheet are estimated by management based on our net ownership interest, estimated costs to abandon and reclaim and the estimated timing of the costs to be incurred in future periods.

We have estimated the net present value of our decommissioning liability to be $579.0 million at September 30, 2012 compared to $563.8 million at December 31, 2011. The majority of this increase relates to the risk-free rate used to calculate the present value of the future cash outflows, which decreased to 2.32% at September 30, 2012 from 2.49% at December 31, 2011. See Note 9 for further information.

Taxes

CURRENT INCOME TAXES

We recorded a current tax recovery of $2.2 million for the three months ended September 30, 2012 compared to $32.3 million expense for the same period in 2011. The majority of our tax expense recorded in the third quarter 2011 related to an adjustment to Alternative Minimum Tax ("AMT") as well as AMT on current period income. Our current tax recovery recorded in the third quarter of 2012 resulted from the E&E impairment charge in the U.S. Our current tax is comprised mainly of AMT payable with respect to our U.S. subsidiary. We expect to recover AMT in future years as an offset to regular U.S. income taxes otherwise payable.

We are now expecting to pay U.S. AMT between 2 - 3% of our U.S. cash flow in 2012 and 2013. We do not expect to pay material cash taxes in Canada until after 2015 as we have sufficient tax pools to offset our anticipated taxable income prior to that time. These estimates may vary depending on numerous factors, including but not limited to fluctuating commodity prices, production levels, capital spending and acquisition or disposition activity.

DEFERRED INCOME TAXES

We recorded a deferred income tax recovery of $37.2 million for the three months ended September 30, 2012 compared to a $15.5 million expense for the same period in 2011. The decrease in deferred income tax expense primarily relates to the decrease in income from 2011 as well as other non-taxable gains included in income.

Net Income/(Loss)

The third quarter of 2012 resulted in a net loss of $63.5 million or $0.32 per share compared to net income of $111.3 million or $0.62 per share in the third quarter of 2011. In the third quarter of 2012 we had $40.8 million of mark-to-market losses on our commodity derivative instruments compared to a gain of $117.1 million during the same period of 2011. As well we recorded impairments of $113.8 million from the writedown of E&E properties during the third quarter of 2012.

For the nine months ended September 30, 2012 net income was $3.0 million or nil per share compared to $408.9 million or $2.28 per share for the same period in 2011. The decrease in net income compared to the prior year resulted primarily from the $271.9 million gain recorded in 2011 on our Marcellus property disposition as well as $200.7 million of impairments recorded during 2012 that related to the decrease in natural gas prices and the writedown of E&E properties.

Selected Canadian and U.S. Results

The following table provides a geographical analysis of key operating and financial results for the three and nine months ended September 30, 2012 and 2011.

	Three months ended September 30, 2012			Three months ended September 30, 2011		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	20,249	16,561	36,810	18,646	10,691	29,337
Natural gas liquids (bbls/day)	3,056	482	3,538	3,065	230	3,295
Natural gas (Mcf/day)	193,819	53,528	247,347	215,826	27,849	243,675
Total average daily production (BOE/day)	55,608	25,965	81,573	57,682	15,563	73,245
Pricing(1)						
Crude oil (per bbl)	$ 74.42	$ 78.83	$ 76.41	$ 77.63	$ 77.45	$ 77.57
Natural gas liquids (per bbl)	50.56	30.40	47.81	65.77	54.36	64.98
Natural gas (per Mcf)	1.94	3.14	2.20	3.65	4.32	3.73
Capital Expenditures						
Capital spending	$ 48.4	$ 118.6	$ 167.0	$ 64.8	$ 136.5	$ 201.3
Acquisitions	–	7.3	7.3	31.5	35.8	67.3
Dispositions	(3.0)	(0.1)	(3.1)	2.2	(9.5)	(7.3)
Revenues						
Oil and gas sales(1)	$ 189.3	$ 135.6	$ 324.9	$ 224.5	$ 88.4	$ 312.9
Royalties(2)	(28.0)	(36.6)	(64.6)	(32.7)	(23.4)	(56.1)
Commodity derivative instruments	(40.8)	–	(40.8)	117.1	–	117.1
Expenses						
Operating	$ 79.8	$ 14.7	$ 94.5	$ 63.6	$ 10.0	$ 73.6
G&A and Equity Based Compensation	19.8	3.9	23.7	16.5	2.8	19.3
Depletion, depreciation and amortization	78.6	54.2	132.8	84.2	24.7	108.9
Impairment	47.9	65.9	113.8	–	–	–
Current income taxes	0.2	(2.4)	(2.2)	–	32.3	32.3

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) U.S. royalties include state production tax.

(CDN$ millions, except per unit amounts)	Nine months ended September 30, 2012			Nine months ended September 30, 2011		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	20,625	15,182	35,807	18,923	10,742	29,665
Natural gas liquids (bbls/day)	3,266	378	3,644	3,169	154	3,323
Natural gas (Mcf/day)	201,625	47,421	249,046	219,446	30,798	250,244
Total average daily production (BOE/day)	57,495	23,464	80,959	58,666	16,029	74,695
Pricing(1)						
Crude oil (per bbl)	$ 76.28	$ 82.02	$ 78.72	$ 80.56	$ 84.56	$ 82.01
Natural gas liquids (per bbl)	57.07	36.03	54.88	64.53	50.73	63.89
Natural gas (per Mcf)	1.99	2.98	2.18	3.67	4.93	3.83
Capital Expenditures						
Capital spending	$ 205.2	$ 487.5	$ 692.7	$ 196.5	$ 324.4	$ 520.9
Acquisitions	13.8	50.1	63.9	91.0	118.9	209.9
Dispositions	(33.7)	(21.9)	(55.6)	(60.7)	(577.4)	(638.1)
Revenues						
Oil and gas sales(1)	$ 594.3	$ 384.0	$ 978.3	$ 694.2	$ 291.6	$ 985.8
Royalties(2)	(92.4)	(101.4)	(193.8)	(104.0)	(72.9)	(176.9)
Commodity derivative instruments	74.3	–	74.3	92.8	–	92.8
Expenses						
Operating	$ 208.2	$ 38.9	$ 247.1	$ 173.1	$ 25.1	$ 198.2
G&A and Equity Based Compensation	58.9	11.0	69.9	61.8	8.2	70.0
Depletion, depreciation and amortization	239.1	140.4	379.5	246.1	66.4	312.5
Impairment	134.8	65.9	200.7	32.4	–	32.4
Current income taxes	0.1	2.2	2.3	–	76.3	76.3

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) U.S. royalties include state production tax.

Quarterly Financial Information

Oil and gas sales have been relatively flat in 2012 as higher production volumes offset the impact of lower realized commodity prices. During 2011 and 2010 the impact of higher crude oil prices was generally offset by the decline in natural gas prices as well as a reduction in production levels due to our disposition activity, resulting in flat oil and gas sales during those periods.

Net income was also affected by fluctuating risk management costs, impairments related to the decrease in natural gas prices, gains on asset dispositions along with changes in tax provisions.

Quarterly Financial Information ($ millions, except per share amounts)		**Oil and Gas Sales**[1]		**Net Income/(Loss)**		**Net Income/(Loss) Per Share Basic**		**Net Income/(Loss) Per Share Diluted**
2012								
Third Quarter	$	324.9	$	(63.5)	$	(0.32)	$	(0.32)
Second Quarter		314.4		100.3		0.51		0.51
First quarter		339.0		(33.8)		(0.18)		(0.18)
Total	$	978.3	$	3.0	$	0.02	$	0.02
2011								
Fourth Quarter	$	357.3	$	(299.4)	$	(1.66)	$	(1.65)
Third Quarter		312.9		111.3		0.62		0.62
Second Quarter		354.2		268.0		1.50		1.49
First Quarter		318.7		29.5		0.17		0.16
Total	$	1,343.1	$	109.4	$	0.61	$	0.61
2010								
Fourth Quarter	$	313.2	$	64.5	$	0.37	$	0.36
Third Quarter		305.5		(136.3)		(0.77)		(0.77)
Second Quarter		318.2		76.5		0.44		0.38
First Quarter		363.3		(184.0)		(1.05)		(1.08)
Total	$	1,300.2	$	(179.3)	$	(1.02)	$	(1.02)

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

LIQUIDITY AND CAPITAL RESOURCES

We continue to manage our balance sheet in the context of the current natural gas price environment and our 2012 capital program. In the first six months of 2012 we completed an equity offering raising net proceeds of $331 million and also closed an approximate $405 million private placement of senior unsecured notes with maturities extending out 12 years. In the third quarter we sold our shares in Laricina Energy for net proceeds of $141 million and realized an economic gain of approximately $86.5 million.

We have also implemented a number of other initiatives to help manage our balance sheet. In the second quarter we replaced our Dividend Reinvestment Program ("DRIP"), which was only available to Canadian shareholders, with a Stock Dividend Program that is available to all shareholders. We are pleased with the current participation rate of approximately 18% and expect this rate to increase over time due to the favorable tax attributes of this program. We also announced a reduction in our monthly dividend from CDN$0.18 per share to CDN$0.09 per share, effective for our July 20, 2012 payment. Given the current commodity price environment this reduction will allow for continued investment in our asset base in a more sustainable manner.

We continue to pursue other measures to support our capital spending activities including the sale or joint venture of our undeveloped land or the sale of non-core producing properties. We have retained advisors with respect to our Duvernay and Montney interests and are actively marketing these assets. Subsequent to the third quarter we entered into an agreement to sell all of our non-core assets in Manitoba for gross proceeds of approximately $220 million.

Total debt at September 30, 2012, including the current portion, was $1,118.6 million compared to $907.1 million at December 31, 2011, representing a $211.5 million increase. Total debt at September 30, 2012 was comprised of $307.3 million of bank indebtedness and $811.3 million of senior notes. Our capital spending, acquisitions and cash dividends have exceeded our cash flow and proceeds realized on our equity issue and equity portfolio sale which has increased our debt balance. We have $692.7 million of available credit on our bank credit facility at September 30, 2012 and a trailing twelve month debt to funds flow ratio of 1.9x.

Our working capital deficiency, excluding cash and current deferred financial assets and credits, was $191.0 million at September 30, 2012, improving by $171.6 million from $362.6 million at December 31, 2011. The change in our working capital deficit resulted from decreased accounts payable balances due to lower capital spending compared to the fourth quarter of 2011 as well as lower dividends payable following the reduction of our monthly dividend. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our payout ratio, which is calculated as cash dividends divided by funds flow, was 33% for the third quarter of 2012 compared to 79% for the third quarter of 2011. Our adjusted payout ratio, which is calculated as cash dividends plus capital spending and office capital divided by funds flow, was 159% for the third quarter of 2012 compared to 245% for the third quarter of 2011. We continue to expect our payout and adjusted payout ratios to moderate going forward given the reduction in our monthly dividend, our new Stock Dividend Program and forecasted growth in funds flow.

Our key leverage ratios are detailed below:

Financial Leverage and Coverage	September 30, 2012	December 31, 2011
Long-term debt to funds flow (12 month trailing)(1)	1.9 x	1.6 x
Funds flow to interest expense (12 month trailing)(2)	11.8 x	12.2 x
Long-term debt to long-term debt plus equity(1)	26%	22%

(1) Long-term debt is measured net of cash and includes the current portion of the senior notes.
(2) Interest expense is calculated as finance expense excluding non-cash items.

Subsequent to September 30, 2012 we extended our unsecured, covenant-based, $1.0 billion bank credit facility by a year to October 31, 2015. Drawn and undrawn fees under the facility did not change with the extension and range between 160 and 325 basis points over bankers' acceptance rates. We are currently paying 180 basis points over bankers' acceptance rates, which are trading around 1.3%, for a combined rate of 3.1%.

At September 30, 2012 we were in compliance with our debt covenants. Our bank credit facility and senior note purchase agreements have been filed as material documents on the Company's SEDAR profile at www.sedar.com.

Dividends

During the three and nine months ended September 30, 2012 we reported a total of $53.4 million ($0.27/share) and $248.0 million ($1.26/share) in dividends to our shareholders, of which $8.5 million and $14.0 million respectively, was non-cash and related to our Stock Dividend Program. On June 12, 2012, we announced a reduction in our monthly dividend from CDN$0.18 per share to CDN$0.09 per share, effective for our July 20, 2012 dividend payment. We continue to assess our dividend levels with respect to anticipated funds flow, debt levels, capital spending plans and capital market conditions.

Participation in the Stock Dividend Program is optional allowing our shareholders to continue to receive cash dividends unless they elect to receive stock dividends. Currently we have a participation rate of approximately 18% or $3.0 million per month. As with the DRIP, the Stock Dividend Program will serve as a source of capital by allowing us to retain cash that would otherwise be paid out as dividends.

Shareholders' Capital

During the third quarter of 2012, a total of 604,000 shares (2011 – 595,000) were issued pursuant to the Stock Dividend Program, resulting in $8.5 million (2011 – $15.4 million) of additional equity for the company. For the nine months ended September 30, 2012, a total of 2,068,000 shares (2011 – 1,934,000) and $34.3 million of additional equity (2011 – $49.7 million) was issued pursuant to the Stock Dividend Program, our former DRIP and the stock option plan. On February 8, 2012 we completed a bought deal equity financing of 14,708,500 common shares at a price of $23.45 per share for gross proceeds of $344.9 million ($330.6 million net of issuance costs). For further details see Note 13.

We had 197,936,000 shares outstanding at September 30, 2012 compared to 180,582,000 shares outstanding at September 30, 2011. We had 181,159,000 shares outstanding at December 31, 2011. The weighted average basic number of shares outstanding for the nine months ended September 30, 2012 was 194,753,000 (2011 – 179,566,000). At October 31, 2012 we had 198,147,000 shares outstanding.

2012 GUIDANCE

A summary of our updated 2012 guidance is below. This guidance does not include any potential acquisitions or divestments.

Summary of 2012 Expectations	Target	Comments
Average annual production	82,000 BOE/day	Decreased from 83,500 BOE/day
Exit rate production	85,000 – 88,000 BOE/day	Changed from 88,000 BOE/day
Capital spending	$850 million	No change
Marcellus carry commitment spending	Nil	Carry commitment fully satisfied at September 30, 2012.
Exit production mix (volumes)	50% natural gas, 50% crude oil and liquids	No change
Average royalty rate (% of gross sales, net of transportation)	21%	No change
Operating costs	$10.70/BOE	Increased from $10.40/BOE due to revised production guidance
G&A and equity based compensation expenses	$3.30/BOE	No change
Average interest and financing costs	6%	No change

INTERNAL CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the period beginning on July 1, 2012 and ending on September 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

FORWARD-LOOKING INFORMATION AND STATEMENTS

*This MD&A contains certain forward-looking information and forward-looking statements within the meaning of applicable securities laws ("**forward-looking information**"). 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 MD&A contains forward-looking information pertaining to the following: expected 2012 and 2013 average and 2012 exit production volumes and the anticipated production mix; the results from our Fort Berthold drilling program and the timing of related production; future oil and natural gas prices and our commodity risk management programs; future royalty rates on our production; anticipated cash and non-cash G&A and financing expenses; operating costs; capital spending levels in 2012 and its impact on our production levels; the amount of our future abandonment and reclamation costs and decommissioning liabilities; our 2012 U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and debt-to-funds-flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; the amount and timing of future cash dividends that we may pay to our shareholders; the amount and timing of future debt and equity issuances and expected use of proceeds therefrom; and the amount and timing of, and use of proceeds from, future asset dispositions, including the sale of our non-core producing assets in Manitoba.*

The forward-looking information contained in this MD&A reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our 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 our reserve and resource volumes; commodity price and cost assumptions; the continued availability of adequate debt and/or equity financing and funds flow to fund our capital and operating requirements and dividend payments as needed; the availability of third party services; and the extent of our liabilities. We believe 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 MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: changes in commodity prices; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties, increased debt levels or debt service requirements; inaccurate estimation of our oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; a failure to complete planned asset dispositions on the terms anticipated or at all; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in our MD&A for the year ended December 31, 2011 and under "Risk Factors" in our Annual Information Form for the year ended December 31, 2011 dated March 9, 2012, which are available on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com and which form part of our Form 40-F filed with the SEC on March 9, 2012 available on EDGAR at www.sec.gov.

The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.