Management's Discussion and Analysis

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

The following discussion and analysis of financial results is dated November 7, 2013 and is to be read in conjunction with:

- the unaudited interim consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three and nine months ended September 30, 2013 and 2012 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at and for the years ended December 31, 2012 and 2011 (the "Financial Statements"); and
- the MD&A of Enerplus for the year ended December 31, 2012 (the "Annual MD&A").

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 ("NGL") 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 ("NI 51-101") 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 discussion at 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 International Financial Reporting Standards ("IFRS") and therefore may not be comparable with the calculation of similar measures by other entities:

"Adjusted payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate our adjusted payout ratio as dividends to shareholders, net of our stock dividends and the Company's former Dividend Reinvestment Plan ("DRIP") proceeds, 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

During the third quarter we continued to deliver strong production levels averaging 87,729 BOE/day. As we expected, production decreased 3% from the second quarter of 2013 due to planned turnaround activity, reduced capital spending earlier in the year, and the impact of non-core asset dispositions. With strong performance from our core Canadian properties and higher than anticipated production from our Fort Berthold and Marcellus properties, we have increased our annual average production guidance to 87,500 BOE/day from 85,000 BOE/day. Our development capital program remains on track with spending of $145.8 million during the quarter, primarily focused on our Fort Berthold and Canadian crude oil properties. Operating expenses of $10.60/BOE and general and administrative expenses ("G&A") of $2.48/BOE were in line with expectations during the quarter.

Third quarter funds flow totaled $196.2 million, an increase of 45% from the same period in 2012. As expected, lower production during the quarter resulted in funds flow decreasing by 4% compared to the second quarter of 2013. Net income for the quarter totaled $34.0 million, up from a $63.5 million net loss in the same period of 2012 due to higher production volumes and improved realized pricing as well as no impairment charges recorded against our assets.

We have continued to focus our asset portfolio and improve our financial flexibility through our acquisition and disposition activity. In the third quarter, we realized proceeds of $124.5 million on our disposition activities. Subsequent to the quarter we signed agreements for additional dispositions including non-core Canadian oil assets for proceeds of approximately $105 million before closing adjustments, along with our undeveloped Montney acreage for proceeds of approximately $130 million. We also entered into an agreement to acquire additional working interests in our existing non-operated Marcellus leases in northeast Pennsylvania for approximately US$153 million before closing adjustments. The Marcellus acquisition is expected to close at the end of November 2013 and will increase our 2013 exit rate guidance to 95,000 BOE/day from 88,000 BOE/day. Our 2013 annual average production and capital spending forecast is not expected to change materially as a result of the acquisition.

Our adjusted payout ratio continued to improve at 97% for the third quarter and 103% year-to-date, due to strong production and funds flow growth as well as improving capital efficiencies. At September 30, 2013, we had a conservative trailing twelve month debt to funds flow ratio of 1.2x and approximately $815.0 million of available capacity on our bank credit facility.

RESULTS OF OPERATIONS

Production

Production decreased to 87,729 BOE/day in the third quarter of 2013 from 90,037 BOE/day in the second quarter, which was expected given planned turnaround activity, reduced capital spending earlier in 2013, and the disposition of approximately 1,300 BOE/day (net of acquisitions) throughout the first nine months of the year. Compared to the same periods in 2012, production increased 8% during the quarter and 9% year-to-date mainly due to increased production from our Fort Berthold and Marcellus assets.

Our weighting of crude oil and liquids production was 48% during the third quarter. We continue to expect our crude oil and liquids weighting to average 48% for 2013.

Average daily production volumes for the three and nine months ended September 30, 2013 and 2012 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2013**	**2012**	**% Change**	**2013**	**2012**	**% Change**
Crude oil (bbls/day)	38,883	36,810	6%	38,426	35,807	7%
Natural gas liquids (bbls/day)	2,985	3,538	(16)%	3,357	3,644	(8)%
Natural gas (Mcf/day)	275,164	247,347	11%	279,212	249,046	12%
Total daily sales (BOE/day)	87,729	81,573	8%	88,318	80,959	9%

Based on our strong production performance we have increased our annual average production guidance to 87,500 BOE/day from 85,000 BOE/day, despite the sale of 2,200 BOE/day. We have also increased our exit rate guidance to 95,000 BOE/day from 88,000 BOE/day to reflect the acquisition of additional working interests in the Marcellus that are expected to close at the end of November.

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 quarterly average prices from the third quarter of 2012 to the third quarter of 2013.

	Nine months ended September 30						
Pricing (average for the period)	2013	2012	Q3 2013	Q2 2013	Q1 2013	Q4 2012	Q3 2012
Benchmarks							
WTI crude oil (US$/bbl)	$ 98.14	$ 96.21	$ 105.82	$ 94.22	$ 94.37	$ 88.18	$ 92.22
AECO – monthly index (CDN$/Mcf)	3.16	2.18	2.82	3.59	3.08	3.06	2.19
AECO – daily index (CDN$/Mcf)	3.05	2.11	2.43	3.53	3.20	3.22	2.29
NYMEX – monthly NX3 (US$/Mcf)	3.68	2.62	3.60	4.09	3.35	3.36	2.81
US/CDN exchange rate	1.02	1.00	1.04	1.02	1.01	0.99	1.00
Enerplus selling price[(1)]							
Crude oil (per bbl)	$ 86.05	$ 78.72	$ 96.30	$ 82.95	$ 78.52	$ 76.75	$ 76.41
Natural gas liquids (per bbl)	51.48	54.88	49.88	45.64	58.58	47.31	47.81
Natural gas (per Mcf)	3.26	2.18	2.96	3.70	3.10	3.01	2.20
Average differentials (US$/bbl or US$/Mcf)							
MSW Edmonton – WTI	$ (5.11)	$ (9.27)	$ (4.72)	$ (3.67)	$ (6.95)	$ (3.32)	$ (7.21)
WCS Hardisty – WTI	(22.86)	(22.00)	(17.48)	(19.16)	(31.96)	(18.11)	(21.72)
Brent Futures (ICE) – WTI	10.40	16.00	3.83	9.14	18.24	21.81	17.22
AECO monthly – NYMEX	(0.62)	(0.41)	(1.00)	(0.58)	(0.28)	(0.31)	(0.60)
Enerplus realized differentials[(1)]							
U.S. crude oil – WTI	$ (8.84)	$ (14.29)	$ (11.41)	$ (9.61)	$ (6.10)	$ (5.18)	$ (12.90)
Canada crude oil – WTI	(19.96)	(20.08)	(15.18)	(16.97)	(26.97)	(15.54)	(17.41)
U.S. natural gas – NYMEX	0.02	0.36	(0.18)	0.08	0.12	0.34	0.34
Canada natural gas – NYMEX	(0.77)	(0.64)	(1.08)	(0.78)	(0.49)	(0.57)	(0.86)

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

Crude Oil and Natural Gas Liquids

WTI crude oil prices averaged US$105.82 during the third quarter. Geopolitical tensions in the Middle East combined with a significant draw in light sweet oil inventories in the U.S. as refineries returned from planned and unplanned shutdowns, pushed WTI prices to a high of over US$110/bbl before falling back to approximately US$102/bbl at the end of September. This resulted in dramatically increased backwardation along the forward curve.

Differentials for Canadian crude oil remained relatively tight for July and August as maintenance in the oil sands and delays in new heavy oil production provided significant price support. However, heavy differentials widened as increased Canadian heavy oil production was met with a seasonal decline in refinery demand and lower runs, resulting in a much weaker demand for heavy oil in the market late in the quarter. Differentials in the U.S. widened slightly in the third quarter to US$11.41/bbl below WTI as production in the region continued to increase at a rapid pace and as Gulf Coast refiners continued to deal with a rising influx of light sweet crude oil.

Natural gas liquids ("NGL") prices increased compared to the previous quarter, in line with the strength in WTI prices. However year over year, our realized NGL pricing has decreased as a result of higher fractionation and transportation costs due to capacity constraints in the local Alberta market. We expect realized NGL prices to remain weak through the balance of the year and into 2014 until new fractionation capacity is built in the province.

The average price received for our crude oil production (net of transportation costs) in the third quarter of 2013 increased 16% to $96.30/bbl compared to the second quarter and was up 26% from the same period in 2012. The improvement in our pricing is due to increasing WTI prices along with a higher proportion of our production being light crude oil from our Fort Berthold properties. Our realized differentials relative to WTI remained relatively flat, as the impact of widening U.S. differentials was offset by narrowing Canadian differentials.

Natural Gas

Natural gas prices weakened during the third quarter as below normal temperatures across key regions in North America failed to generate cooling demand during the summer. In addition, increasing U.S. gas production and the displacement of gas-fired power generation due to low coal prices put further downward pressure on the natural gas market.

In Canada, prices at AECO fell relative to NYMEX as the market adjusted to a new tolling mechanism mandated by the National Energy Board on the TransCanada mainline. TransCanada is now allowed to use its discretion in setting short-term firm service and interruptible rates on this pipeline. These rates were set at two to three times the cost of long-term firm service, resulting in a significant widening of the basis differential between AECO and Henry Hub. In addition, various short-term pipeline outages due to the floods in June, along with high western Canadian storage levels, led to further weakness in Canadian gas prices in September.

In the U.S., spot prices on Tennessee Gas Pipeline ("TGP") and Transco in the northeast weakened significantly through the quarter with increasing Marcellus production and capacity constraints due to maintenance on these pipelines. We have long-term sales contracts in place that are based on both monthly and daily regional index prices that provide some protection from the much weaker TGP and Transco spot markets. Because of these agreements, our average Marcellus price was approximately US$0.52/Mcf below NYMEX prices during the quarter, compared to benchmark daily spot discounts on the Tennessee Gas Pipeline 300 line and Transco Leidy line ranging between US$1.16/Mcf and US$2.11/Mcf below NYMEX. We expect that wider differentials will continue in the region until pipeline expansions are built to manage excess gas from the producing areas. Accessing new and incremental markets will be necessary to consume the growing gas production in the Marcellus region.

For the three months ended September 30, 2013 we sold our natural gas for an average price of $2.96/Mcf (net of transportation costs) which represented a 20% decrease from an average price of $3.70/Mcf received during the second quarter of 2013 and a 35% increase compared to the same period in 2012. Of our total gas production during the current quarter, 63% was from Canada with an average price of $2.62/Mcf and 37% was from the U.S. at $3.55/Mcf, net of transportation. In the third quarter of 2012 our Canadian production was 78% of our total gas production. Our realized prices were in-line with the widening of the AECO and NYMEX differentials during this period along with the widening differential experienced in the Marcellus region.

Price Risk Management

We have a price risk management program that is designed to mitigate a portion of the variability in commodity prices. The program considers our overall financial position along with the economics of our capital program and potential acquisitions. Our crude oil production accounted for approximately 81% of our corporate netback for the nine months ended September 30, 2013 and therefore we believe it is prudent to have a significant level of downside price protection. As of October 22, 2013 we have swapped 22,500 bbls/day for the remainder of 2013 at an average price of US$100.36/bbl, representing approximately 74% of our forecasted net crude oil production after royalties. For the first half of 2014, we have swapped 20,000 bbls/day, representing approximately 66% of our forecasted net crude oil production after royalties, at an average price of US$93.70/bbl. For the second half of 2014 we have swapped 15,000 bbls/day, representing approximately 49% of our forecasted net crude oil production after royalties, at an average price of US$92.73/bbl. In addition we have swapped 500 bbl/day at US$90.00/bbl for 2015, representing approximately 2% of our net crude oil production after royalties.

In order to diversify away some of our crude oil price exposure from North America, we have also added Brent – WTI fixed and ratio spread basis positions. We have entered into fixed basis spread positions for the remainder of 2013 where we pay the WTI calendar month average price and receive the Brent calendar month average price less a fixed spread of US$7.09/bbl on 5,000 bbls/day. For 2014 we have entered into ratio spread basis positions where we pay the WTI calendar month average price and receive 93.1% of the Brent calendar month average price on 3,000 bbls/day.

For the remainder of 2013 and 2014, we have also entered into Western Canadian Select ("WCS") and Edmonton Light Sweet ("MSW") differential swap positions. WCS differentials have been fixed at WTI less US$21.56/bbl for the remainder of 2013 on 2,000 bbls/day and WTI less US$23.25/bbl for 2014 on 1,000 bbls/day. MSW differentials have been fixed at WTI less US$5.90/bbl for the remainder of 2013 on 500 bbls/day.

As of October 22, 2013 we had downside protection representing approximately 31% of our forecasted natural gas production after royalties for the remainder of 2013. This protection is comprised of 51,100 Mcf/day at AECO $3.41/Mcf before premiums and 15,000 Mcf/day swapped at NYMEX US$3.85/Mcf. For 2014 we have swapped 50,000 Mcf/day at NYMEX US$4.17/Mcf and another 4,700 Mcf/day at AECO $3.96/Mcf, representing approximately 25% of our forecasted net natural gas production after royalties.

The following is a summary of our financial contracts in place at October 22, 2013 expressed as a percentage of our anticipated net production volumes after royalties:

	WTI Crude Oil(1) (US$/bbl)			AECO Natural Gas(1) (CDN$/Mcf)		NYMEX Natural Gas(1) (US$/Mcf)	
	Oct 1, 2013 – Dec 31, 2013	Jan 1, 2014 – Jun 30, 2014	Jul 1, 2014 – Dec 31, 2014	Oct 1, 2013 – Dec 31, 2013	Jan 1, 2014 – Dec 31, 2014	Oct 1, 2013 – Dec 31, 2013	Jan 1, 2014 – Dec 31, 2014
Purchased Puts	–	–	–	$ 3.17	–	–	–
%	–	–	–	11%	–	–	–
Sold Puts	$ 63.09	–	–	–	–	–	–
%	18%	–	–	–	–	–	–
Swaps (fixed price)	$ 100.36	$ 93.70	$ 92.73	$ 3.61	$ 3.96	$ 3.85	$ 4.17
%	74%	66%	49%	13%	2%	7%	23%
Sold Calls	$ 130.00	–	–	–	–	–	–
%	11%	–	–	–	–	–	–
Purchased Calls	$ 104.09	–	–	–	–	–	–
%	11%	–	–	–	–	–	–

(1) Based on weighted average price (before premiums), assumed average annual production of 87,500 BOE/day for 2013 and 2014, less royalties of 21%.

For 2015 we have swapped 500 bbls/day of crude oil at US$90.00/bbl, representing approximately 2% of our forecasted net production after royalties. See Note 15 for further information on our commodity hedging.

Accounting for Price Risk Management

During the third quarter of 2013 we realized cash losses of $12.9 million on our crude oil contracts and cash gains of $2.3 million on our natural gas contracts. In comparison, during the third quarter of 2012 we realized cash gains of $7.9 million on our crude oil contracts. The crude oil losses realized in the current quarter are due to market prices rising above our fixed price positions. The natural gas gain realized during the current quarter and the crude oil gain recognized in the same period in 2012 were due to contracts that provided floor protection above market prices.

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. At the end of the third quarter of 2013 the fair value of our crude oil contracts represented a loss position of $15.8 million, while our natural gas contracts represented a gain position of $7.6 million. For the three and nine months ended September 30, 2013 the fair value of our crude oil contracts decreased $45.6 million and $66.5 million respectively, while the fair value of our natural gas contracts increased $0.5 million and $4.3 million respectively.

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	Three months ended September 30, 2013		2012	
Cash gains/(losses):				
Crude Oil	$ (12.9)	$ (3.59)/bbl	$ 7.9	$ 2.34/bbl
Natural Gas	2.3	$ 0.09/Mcf	–	$ – /Mcf
Total cash gains/(losses)	$ (10.6)	$ (1.30)/BOE	$ 7.9	$ 1.06/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – crude oil	$ (45.6)	$ (12.75)/bbl	$ (47.3)	$ (13.98)/bbl
Change in fair value – natural gas	0.5	$ 0.02/Mcf	(1.4)	$ 0.06)/Mcf
Total non-cash gains/(losses)	$ (45.1)	$ (5.60)/BOE	$ (48.7)	$ (6.49)/BOE
Total gains/(losses)	**$ (55.7)**	**$ (6.90)/BOE**	**$ (40.8)**	**$ (5.43)/BOE**

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	Nine months ended September 30, 2013				2012			
Cash gains/(losses):								
Crude Oil	$	9.0	$	0.86/bbl	$	2.3	$	0.23/bbl
Natural Gas		1.1	$	0.01/Mcf		–	$	– /Mcf
Total cash gains/(losses)	$	10.1	$	0.42/BOE	$	2.3	$	0.11/BOE
Non-cash gains/(losses) on financial contracts:								
Change in fair value – crude oil	$	(66.5)	$	(6.34)/bbl	$	73.3	$	7.47/bbl
Change in fair value – natural gas		4.3	$	0.06/Mcf		(1.4)	$	(0.02)/Mcf
Total non-cash gains/(losses)	$	(62.2)	$	(2.58)/BOE	$	71.9	$	3.24/BOE
Total gains/(losses)	**$**	**(52.1)**	**$**	**(2.16)/BOE**	**$**	**74.2**	**$**	**3.35/BOE**

Revenues

Crude oil and natural gas revenues were $432.7 million ($441.5 million, net of $8.8 million of transportation costs) in the third quarter of 2013, representing an increase of $107.8 million or 33% from $324.9 million ($331.7 million, net of $6.8 million of transportation costs) during the same period in 2012. Crude oil and natural gas revenues for the nine months ended September 30, 2013 were $1,197.5 million ($1,219.8 million, net of $22.3 million of transportation costs), an increase of $219.2 million or 22% from $978.3 million ($998.1 million, net of $19.8 million in transportation costs) for the same period in 2012. Crude oil and natural gas revenues increased due to higher realized prices and higher production levels during both periods.

Analysis of Sales Revenue[(1)] ($ millions)		Crude Oil		NGLs		Natural Gas		Total
Three months ended September 30, 2012	$	258.7	$	15.6	$	50.6	$	324.9
Price variance		71.2		0.4		18.5		90.1
Volume variance		14.6		(2.3)		5.4		17.7
Three months ended September 30, 2013	**$**	**344.5**	**$**	**13.7**	**$**	**74.5**	**$**	**432.7**

($ millions)		Crude Oil		NGLs		Natural Gas		Total
Nine months ended September 30, 2012	$	772.3	$	54.8	$	151.2	$	978.3
Price variance		76.9		(3.1)		79.6		153.4
Volume variance		53.5		(4.5)		16.8		65.8
Nine months ended September 30, 2013	**$**	**902.7**	**$**	**47.2**	**$**	**247.6**	**$**	**1,197.5**

(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, 2013 royalties were $96.1 million and $252.1 million respectively, compared to $64.6 million and $193.8 million for the same periods of 2012. As a percentage of oil and gas sales, net of transportation costs, royalties were 22% and 21% for the three and nine months ended September 30, 2013 respectively, compared to 20% for the same periods in 2012. The increase in our royalty rate is due to higher crude oil and natural gas prices compared to the prior year as well as an increased proportion of U.S. production where royalty rates are higher than those on our Canadian production. We continue to expect an average royalty rate of approximately 21% in 2013.

Operating Expenses

Operating expenses were in line with expectations at $85.5 million or $10.60/BOE during the third quarter of 2013 and $252.3 million or $10.46/BOE for the nine months ended September 30, 2013. In comparison, operating expenses for the three and nine months ended September 30, 2012 were $94.5 million or $12.59/BOE and $247.1 million or $11.14/BOE respectively.

Operating costs in the third quarter of 2013 were lower than the same period in 2012 due to increased production from our U.S. properties with lower operating costs, the disposition of higher operating cost non-core properties, and non-routine expenses incurred in the same period in 2012. For the first nine months of 2013 our spending is marginally higher than the prior year with increased well servicing and repairs and maintenance work, along with increased fluid handling and gas facility charges as a result of our increased production.

We are maintaining our annual guidance of $10.70/BOE for operating costs during 2013.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three and nine months ended September 30, 2013 and 2012. 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 of this MD&A.

	Three months ended September 30, 2013					
Netbacks by Property Type		**Crude Oil**		**Natural Gas**		**Total**
Average Daily Production		43,443 BOE/day		265,714 Mcfe/day		87,729 BOE/day
Netback[1] $ per BOE or Mcfe		(per BOE)		(per Mcfe)		(per BOE)
Revenue[2]	$	87.58	$	3.38	$	53.61
Royalties		(20.66)		(0.55)		(11.91)
Cash operating costs		(12.08)		(1.52)		(10.58)
Netback before hedging	$	54.84	$	1.31	$	31.12
Cash gains/(losses)		(3.22)		0.10		(1.30)
Netback after hedging	$	51.62	$	1.41	$	29.82
Netback before hedging ($ millions)	$	219.2	$	32.0	$	251.2
Netback after hedging ($ millions)	**$**	**206.3**	**$**	**34.3**	**$**	**240.6**

	Three months ended September 30, 2012					
Netbacks by Property Type		**Crude Oil**		**Natural Gas**		**Total**
Average Daily Production		40,561 BOE/day		246,069 Mcfe/day		81,573 BOE/day
Netback[1] $ per BOE or Mcfe		(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 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**

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

Netbacks by Property Type	Nine months ended September 30, 2013					
	Crude Oil		Natural Gas		Total	
Average daily production		42,471 BOE/day		275,084 Mcfe/day		88,318 BOE/day
Netback[1] $ per BOE or Mcfe		(per BOE)		(per Mcfe)		(per BOE)
Revenue[2]	$	78.97	$	3.75	$	49.67
Royalties		(18.62)		(0.48)		(10.46)
Cash operating costs		(12.24)		(1.49)		(10.52)
Netback before hedging	$	48.11	$	1.78	$	28.69
Cash gains/(losses)		0.78		0.01		0.42
Netback after hedging	$	48.89	$	1.79	$	29.11
Netback before hedging ($ millions)	$	557.8	$	134.0	$	691.8
Netback after hedging ($ millions)	**$**	**566.8**	**$**	**135.1**	**$**	**701.9**

Netbacks by Property Type	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 or Mcfe		(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 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**

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

Our crude oil properties accounted for 81% of our corporate netback before hedging for the first nine months of 2013 compared to 87% for the same period in 2012. Crude oil netbacks per BOE and natural gas netbacks per Mcfe, both after hedging, have increased for the three and nine months ended September 30, 2013 primarily due to higher realized crude oil and natural gas prices.

General and Administrative ("G&A") Expenses

G&A expenses for the three and nine months ended September 30, 2013 were $20.0 million or $2.48/BOE and $63.5 million or $2.63/BOE respectively, compared to $18.6 million or $2.48/BOE and $59.9 million or $2.70/BOE for the same periods during 2012. The increased spending during 2013 was primarily related to compensation costs and one-time charges recorded in the first quarter.

Cash G&A Expenses	Three months ended September 30,				Nine months ended September 30,			
	2013		2012		2013		2012	
G&A expenses ($ millions)	$	20.0	$	18.6	$	63.5	$	59.9
G&A expenses (per BOE)	$	2.48	$	2.48	$	2.63	$	2.70

We continue to expect cash G&A expenses to be approximately $2.70/BOE during 2013.

Equity Based Compensation Expenses

Equity based compensation expenses totaled $5.1 million for the third quarter of 2013 and $17.5 million for the nine months ended September 30, 2013, compared to $5.1 million and $10.0 million for the same periods during 2012. These expenses include charges related to our long-term incentive plans ("LTI plans") and our stock option plan (see Note 14 for further details). The costs of our LTI plans are dependent on our share price and can fluctuate from period to period. The increased costs in 2013 are the result of the increase in our share price during the year.

We also recorded non-cash gains on our LTI equity swaps of $1.5 million for the third quarter and $3.8 million for the nine months ended September 30, 2013, compared to $2.7 million and $3.1 million of non-cash gains during the same periods in 2012. Utilizing the swaps, we have effectively fixed the future settlement cost on our LTI plans at a weighted average price of $13.21 per share on 1,130,000 shares, representing approximately 69% of the notional shares outstanding under these plans.

	Three months ended September 30,		Nine months ended September 30,	
Equity Based Compensation Expenses ($ millions)	2013	2012	2013	2012
Cash:				
LTI plans expense	$ 4.9	$ 5.2	$ 14.1	$ 5.4
Non-Cash:				
LTI plans – equity swap gain	(1.5)	(2.7)	(3.8)	(3.1)
Stock option plan	1.7	2.6	7.2	7.7
Total equity based compensation expenses	**$ 5.1**	**$ 5.1**	**$ 17.5**	**$ 10.0**

	Three months ended September 30,		Nine months ended September 30,	
Equity Based Compensation Expenses (Per BOE)	2013	2012	2013	2012
Cash:				
LTI plans expense	$ 0.60	$ 0.69	$ 0.58	$ 0.24
Non-Cash:				
LTI plans – equity swap gain	(0.18)	(0.37)	(0.16)	(0.14)
Stock option plan	0.21	0.35	0.30	0.35
Total equity based compensation expenses	**$ 0.63**	**$ 0.67**	**$ 0.72**	**$ 0.45**

We continue to expect cash equity based compensation charges of approximately $0.60/BOE during 2013.

Finance Expense

Interest on our senior notes and bank credit facility for the three and nine months ended September 30, 2013 totaled $14.7 million and $43.1 million respectively, compared to $14.9 million and $39.1 million for the same periods in 2012. The year-to-date increase is due to an increased weighting of senior notes with higher interest rates compared to 2012. The quarter over quarter decrease was due to lower average debt levels in the third quarter of 2013.

Non-cash amounts recorded in finance expense include accretion of decommissioning liabilities, amortization of debt transaction costs 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 11 for further details.

	Three months ended September 30,		Nine months ended September 30,	
Finance Expense ($ millions)	2013	2012	2013	2012
Interest on senior notes and bank facility	$ 14.7	$ 14.9	$ 43.1	$ 39.1
Non-cash finance expense	3.8	4.0	12.3	13.0
Total finance expense	**$ 18.5**	**$ 18.9**	**$ 55.4**	**$ 52.1**

At September 30, 2013 approximately 76% of our debt was based on fixed interest rates at a weighted average rate of approximately 5.8% and the remaining 24% was based on floating interest rates at a weighted average rate of approximately 2.8%.

Foreign Exchange

For the three and nine months ended September 30, 2013 we recorded a foreign exchange gain of $2.5 million and a foreign exchange loss of $4.0 million respectively, compared to gains of $13.6 million and $18.9 million in the same periods in 2012.

Realized foreign exchange gains were minimal during the quarter and the year-to-date realized loss of $17.7 million is primarily due to the second quarter CCIRS settlement on our US$175 million senior notes. Upon settlement of the swap, we realized a loss of $18.0 million and recognized a corresponding mark-to-market unrealized gain.

We recorded net unrealized foreign exchange gains during the third quarter of $2.6 million, mainly due to mark-to-market gains on our CCIRS and foreign exchange swaps which were partially offset by unrealized losses on the period end translation of our U.S. dollar debt. See Note 12 for further details.

	Three months ended September 30,		Nine months ended September 30,	
Foreign Exchange ($ millions)	**2013**	**2012**	**2013**	**2012**
Realized loss/(gain)	$ 0.1	$ 4.1	$ 17.7	$ 10.0
Unrealized loss/(gain)	(2.6)	(17.7)	(13.7)	(28.9)
Total foreign exchange loss/(gain)	**$ (2.5)**	**$ (13.6)**	**$ 4.0**	**$ (18.9)**

Capital Investment

Capital spending for the third quarter totaled $145.8 million, up slightly from the second quarter of 2013 and lower than $167.0 million spent during the same period in 2012. Our capital program remains on track with guidance of $685 million as we continue to expect higher spending in the fourth quarter. Third quarter spending continued to focus primarily on our crude oil properties with $66.5 million directed towards our Fort Berthold crude oil property and $35.2 million spent on our Canadian oil properties. Spending on our natural gas assets included $23.3 million in the Marcellus and $16.5 million on our deep basin properties in Canada.

Property and land acquisitions for the third quarter totaled $15.8 million, which included $6.4 million for additional land interests in the Canadian deep basin, $7.5 million in Fort Berthold and $1.9 million in the Marcellus. During the third quarter of 2012 we spent $7.3 million on acquisitions, consisting of $2.7 million on additional lands in Fort Berthold and $4.6 million on our Marcellus carry obligation which fully satisfied our carry commitment.

Subsequent to September 30, 2013 we entered into an agreement to purchase additional non-operated working interests in the Marcellus which included approximately 7,000 BOE/day of current production and 17,000 net acres in northeast Pennsylvania for approximately US$153 million.

Dispositions

Property dispositions during the third quarter totaled $124.5 million. These divestments consisted of non-core Canadian properties primarily in Saskatchewan and Alberta with production of approximately 1,100 BOE/day for proceeds of $89.3 million. We also sold facilities in Fort Berthold for proceeds of $35.2 million. With respect to these dispositions we recognized gains of $30.5 million.

Subsequent to September 30, 2013 we entered into agreements to sell non-core Canadian oil properties with production of 900 BOE/day for proceeds of approximately $105 million as well as our undeveloped Montney acreage for proceeds of approximately $130 million.

Our total capital investment activity for the three and nine months ended September 30, 2013 is outlined below:

	Three months ended September 30,		Nine months ended September 30,	
Capital Investment ($ millions)	**2013**	**2012**	**2013**	**2012**
Capital spending	$ 145.8	$ 167.0	$ 458.4	$ 692.7
Office capital	1.2	2.7	3.4	8.8
Sub-total	147.0	169.7	461.8	701.5
Property and land acquisitions	15.8	7.3	71.5	63.9
Property dispositions	(124.5)	(3.1)	(197.1)	(55.6)
Sub-total	(108.7)	4.2	(125.6)	8.3
Total net capital investment	**$ 38.3**	**$ 173.9**	**$ 336.2**	**$ 709.8**

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

DD&A of property, plant and equipment is recognized using the unit-of-production method based on proved plus probable reserves. For the three and nine months ended September 30, 2013 DD&A increased to $138.8 million and $398.2 million respectively, compared to $132.8 million and $379.5 million during the same periods in 2012, primarily due to higher production.

Other Assets

Other assets consist of our portfolio of equity investments in other oil and gas companies. These investments are carried at their estimated fair value with changes in fair value recorded in other comprehensive income. The change in fair value of these investments for the three and nine months ended September 30, 2013 resulted in unrealized gains of $0.9 million and $4.8 million respectively, compared to unrealized losses of $17.4 million and $68.5 million for the same periods in 2012. The unrealized losses in the prior year related primarily to our investment in Laricina Energy Ltd. which we disposed of in the third quarter of 2012.

During the three and nine months ended September 30, 2013 we sold certain marketable securities for proceeds of $0.6 million and $2.5 million, respectively, recognizing gains of $0.2 million and $0.4 million. See Note 8 for further information.

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 $516.8 million at September 30, 2013 compared to $599.7 million at December 31, 2012. For the nine months ended September 30, 2013 there was a $82.9 million decrease in decommissioning liability resulting primarily from the change in the risk-free rate used to calculate the present value of the liability, which increased to 3.07% from 2.36% at December 31, 2012. See Note 10 for further information.

Taxes

Current Income Taxes

We recorded a current tax expense of $7.9 million for the nine months ended September 30, 2013 compared to a $2.3 million expense for the same period in 2012 as a result of higher U.S net income in 2013. Our current tax is comprised mainly of Alternative Minimum Tax ("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 continue to expect to pay U.S. cash taxes of approximately 3% of U.S. cash flow in 2013 and between 3-5% of U.S. cash flow in 2014 and 2015. We currently do not expect to pay material cash taxes in Canada until after 2016. These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisition and disposition activity.

Deferred Income Taxes

We recorded a deferred tax expense of $39.3 million for the nine months ended September 30, 2013 compared to a recovery of $5.2 million for the same period in 2012. The increase in deferred income tax expense is due to higher net income in 2013.

Net Income

Net income for the third quarter of 2013 was $34.0 million or $0.17 per share compared to a net loss of $63.5 million or $0.32 per share for the third quarter of 2012. Net income for the nine months ended September 30, 2013 totaled $81.4 million or $0.41 per share compared to $3.0 million or $0.02 per share for the same period in 2012.

Oil and gas sales increased in 2013 due to higher production volumes and improvements in realized pricing. The combination of an increase in sales and no asset impairments during the current year led to higher earnings compared to the same periods in 2012, which were partially offset by higher mark-to-market losses on our commodity derivatives and lower asset disposition gains.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

The following tables provide a geographical analysis of key operating and financial results for the three and nine months ended September 30, 2013 and 2012.

	Three months ended September 30, 2013			Three months ended September 30, 2012		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	17,246	21,637	38,883	20,249	16,561	36,810
Natural gas liquids (bbls/day)	2,265	720	2,985	3,056	482	3,538
Natural gas (Mcf/day)	174,169	100,995	275,164	193,819	53,528	247,347
Total average daily production (BOE/day)	48,539	39,190	87,729	55,608	25,965	81,573
Pricing(1)						
Crude oil (per bbl)	$ 94.12	$ 98.04	$ 96.30	$ 74.42	$ 78.83	$ 76.41
Natural gas liquids (per bbl)	58.64	22.31	49.88	50.56	30.40	47.81
Natural gas (per Mcf)	2.62	3.55	2.96	1.94	3.14	2.20
Capital Expenditures						
Capital spending	$ 57.0	$ 88.8	$ 145.8	$ 48.4	$ 118.6	$ 167.0
Property and land acquisitions	6.4	9.4	15.8	–	7.3	7.3
Property dispositions	(89.3)	(35.2)	(124.5)	(3.0)	(0.1)	(3.1)
Revenues						
Oil and gas sales(1)	$ 204.1	$ 228.6	$ 432.7	$ 189.3	$ 135.6	$ 324.9
Royalties(2)	(33.0)	(63.1)	(96.1)	(28.0)	(36.6)	(64.6)
Commodity derivative instruments gain/(loss)	(55.7)	–	(55.7)	(40.8)	–	(40.8)
Expenses						
Operating	$ 62.4	$ 23.2	$ 85.6	$ 79.8	$ 14.7	$ 94.5
General and administrative	16.0	4.0	20.0	14.9	3.7	18.6
Equity based compensation	4.7	0.4	5.1	4.9	0.2	5.1
Depletion, depreciation and amortization	59.6	79.2	138.8	78.6	54.2	132.8
Impairment	–	–	–	47.9	65.9	113.8
Current income tax expense	(0.3)	5.5	5.2	0.2	(2.4)	(2.2)

(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, 2013 Canada	U.S.	Total	Nine months ended September 30, 2012 Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	18,253	20,173	38,426	20,625	15,182	35,807
Natural gas liquids (bbls/day)	2,782	575	3,357	3,266	378	3,644
Natural gas (Mcf/day)	179,503	99,709	279,212	201,625	47,421	249,046
Total average daily production (BOE/day)	50,952	37,366	88,318	57,495	23,464	80,959
Pricing(1)						
Crude oil (per bbl)	$ 80.02	$ 91.50	$ 86.05	$ 76.28	$ 82.02	$ 78.72
Natural gas liquids (per bbl)	56.59	26.77	51.48	57.07	36.03	54.88
Natural gas (per Mcf)	2.97	3.78	3.26	1.99	2.98	2.18
Capital Expenditures						
Capital spending	$ 184.4	$ 274.0	$ 458.4	$ 205.2	$ 487.5	$ 692.7
Property and land acquisitions	44.0	27.5	71.5	13.8	50.1	63.9
Property dispositions	(154.5)	(42.6)	(197.1)	(33.7)	(21.9)	(55.6)
Revenues						
Oil and gas sales(1)	$ 589.4	$ 608.1	$ 1,197.5	$ 594.3	$ 384.0	$ 978.3
Royalties(2)	(89.8)	(162.3)	(252.1)	(92.4)	(101.4)	(193.8)
Commodity derivative instruments gain/(loss)	(52.1)	–	(52.1)	74.3	–	74.3
Expenses						
Operating	$ 192.3	$ 60.0	$ 252.3	$ 208.2	$ 38.9	$ 247.1
General and administrative	53.1	10.4	63.5	48.8	11.1	59.9
Equity based compensation	16.3	1.2	17.5	10.1	(0.1)	10.0
Depletion, depreciation and amortization	186.2	212.0	398.2	239.1	140.4	379.5
Impairment	–	–	–	134.8	65.9	200.7
Current income tax expense/(recovery)	(0.3)	8.2	7.9	0.1	2.2	2.3

(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 increased in 2013 mainly due to growing crude oil production and increasing crude oil prices. During 2012 oil and gas sales were relatively flat as increasing production volumes were offset by lower realized commodity prices. During 2011 we saw higher crude oil prices and declining natural gas prices combined with lower production levels, which resulted in fluctuating oil and gas sales throughout the year.

Quarterly Financial Information (CDN$ 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
2013				
Third Quarter	$ 432.7	$ 34.0	$ 0.17	$ 0.17
Second Quarter	398.6	52.6	0.26	0.26
First Quarter	366.2	(5.2)	(0.03)	(0.03)
Total	**$ 1,197.5**	**$ 81.4**	**$ 0.41**	**$ 0.41**
2012				
Fourth Quarter	$ 360.7	$ (158.7)	$ (0.80)	$ (0.80)
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	**$ 1,339.0**	**$ (155.7)**	**$ (0.80)**	**$ (0.80)**
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**

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

LIQUIDITY AND CAPITAL RESOURCES

During the quarter we continued to improve our liquidity and strengthen our balance sheet. Our trailing 12 month debt to funds flow ratio decreased to 1.2x from 1.6x at the end of the second quarter of 2013, and we had approximately $815 million of undrawn credit capacity as at September 30, 2013.

Our adjusted payout ratio, which is calculated as dividends (net of our stock dividends and DRIP proceeds, as applicable) plus capital spending and office capital divided by funds flow, was 97% for the third quarter of 2013 and 103% for the first nine months of 2013, compared to 159% and 206% for the same periods in 2012. This improvement is a result of lower capital spending, higher funds flow as well as the reduction of our monthly dividend from $0.18 to $0.09 at the end of the second quarter of 2012.

Total debt (net of cash) at September 30, 2013 was $964.6 million compared to $1,064.4 million at December 31, 2012. This debt was comprised of $185.3 million of bank indebtedness and $797.6 million of senior notes, less $18.3 million in cash.

Our working capital deficiency at September 30, 2013, excluding deferred financial assets and credits, was $185.8 million compared to $167.2 million at December 31, 2012. We expect to finance our working capital deficiency through funds flow and our bank credit facility.

Our key leverage ratios are detailed below:

Financial Leverage and Coverage	September 30, 2013	December 31, 2012
Long-term debt to funds flow (12 month trailing)(1)	1.2 x	1.7 x
Funds flow to interest expense (12 month trailing)(2)	13.5 x	12.1 x
Long-term debt to long-term debt plus equity(1)	24%	26%

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

Subsequent to September 30, 2013, we extended our $1.0 billion bank credit facility by one year to October 31, 2016. Drawn and undrawn fees decreased 10 basis points across the grid and range between 150 and 315 basis points over Bankers' Acceptance rates. We are currently paying 170 basis points over Bankers' Acceptance rates, which are trading around 1.1%, for a combined rate of approximately 2.8%.

At September 30, 2013 we were in compliance with all covenants under our bank credit facility and senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com.

Dividends

During the three and nine months ended September 30, 2013 we reported dividends of $54.4 million ($0.27/share) and $162.2 million ($0.81/share) respectively, of which $12.0 million and $33.5 million respectively, was non-cash and related to our Stock Dividend Program ("SDP"). We continue to assess our dividend levels with respect to anticipated funds flow, debt levels, capital spending plans and capital market conditions and do not anticipate any changes at this time.

Our SDP allows shareholders to elect to receive their dividends in the form of shares instead of cash. Currently approximately 24% of our shareholders participate in the SDP, representing $4.3 million of dividends per month. As with our previous DRIP, the SDP 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 2013, a total of 1,605,000 shares were issued for $26.9 million pursuant to the SDP and stock option plan. A total of 604,000 shares were issued for $8.5 million under our former DRIP and stock option plan for the same period in 2012. For the nine months ended September 30, 2013, a total of 3,189,000 shares were issued for $48.4 million pursuant to the SDP and stock option plan, compared to 2,068,000 shares issued for $34.3 million during the same period in 2012 under the SDP, former DRIP and stock option plan. See Note 14 for further information.

We had 201,874,000 shares outstanding at September 30, 2013 compared to 197,936,000 shares outstanding at September 30, 2012 and 198,684,000 shares outstanding at December 31, 2012. The weighted average basic number of shares outstanding for the nine months ended September 30, 2013 was 200,002,000 (2012 – 194,753,000). At November 7, 2013 we had 202,142,000 shares outstanding.

CHANGE IN BASIS OF PREPARATION OF FINANCIAL STATEMENTS AND U.S. FILING STATUS

Based on preparing our consolidated financial statements under IFRS, we fail to qualify as a "foreign private issuer" under U.S. securities regulations as of January 1, 2014. This is a result of a test performed the last business day of the second quarter of 2013 whereby over 50% of the book value of our assets were located in the U.S. and over 50% of our common shares were held by U.S. residents. Therefore, in order to retain a U.S. filing status but as a "domestic" filer, we would be required to adopt U.S. Generally Accepted Accounting Principles ("US GAAP") for our 2013 year end reporting, which includes comparative periods for 2012 and 2011. These US GAAP financial statements would satisfy our Canadian filing obligations and IFRS statements would no longer be prepared.

We have prepared our comparative US GAAP statements, and under US GAAP less than 50% of the book value of our assets were located in the U.S. on the last business day of the second quarter of 2013. Ordinarily, an existing domestic filer could change to a foreign private issuer in that event. As a result, we are consulting with U.S. securities regulators on our ability to maintain our foreign private issuer status.

CHANGE IN APPOINTMENT OF INDEPENDENT RESERVES ENGINEER

During the third quarter we appointed Netherland, Sewell & Associates, Inc. to evaluate our reserves and contingent resources associated with our Marcellus interests for the year ended December 31, 2013.

2013 GUIDANCE

A summary of our 2013 guidance is below.

Summary of 2013 Expectations	Target
Average annual production	87,500 BOE/day (increase from 85,000 BOE/day)
Exit rate production	95,000 BOE/day (including the Marcellus acquisition)
Capital spending	$685 million
Production mix (volumes)	48% crude oil and liquids
Average royalty rate (% of gross sales, net of transportation)	21%
Operating costs	$10.70/BOE
G&A expenses – cash	$2.70/BOE
Equity based compensation expenses – cash	$0.60/BOE
Cash taxes (% of U.S. funds flow)	~3%
Average interest and financing costs	5%

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at September 30, 2013, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on July 1, 2013 and ending September 30, 2013 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 2013 and 2014 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged; the results from our drilling program and the timing of related production; future oil and natural gas prices and differentials and our commodity risk management programs; expectations regarding our realized oil and natural gas prices; future royalty rates on our production; anticipated cash and non-cash G&A, equity based compensation and financing expenses; operating costs; capital spending levels in 2013 and its impact on our production level and land holdings; our ability to reallocate funds within our 2013 capital program; potential future asset impairments and reversals; the amount of our future abandonment and reclamation costs and decommissioning liabilities; future environmental expenses; our future 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, and use of proceeds from, future asset dispositions; the potential change of our status from "foreign private issuer" to U.S. domestic issuer as of January 1, 2014 and expected changes in our reporting related thereto; and our ability to improve our trading multiple and create significant value for our shareholders.*

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, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our funds flow and availability under our bank credit facility to fund our working capital deficiency; 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 the Annual MD&A and in our other public filings).

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.