MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of financial results is dated August 7, 2014 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 six months ended June 30, 2014 and 2013 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011 (the "Financial Statements"); and
- our MD&A for the year ended December 31, 2013 (the "Annual MD&A").

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. BOE and Mcfe measures 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 unless otherwise stated. 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 end of the MD&A under "Forward-Looking Information and Statements" for further information.

BASIS OF PRESENTATION

The Interim Financial Statements and notes have been prepared in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified.

In accordance with U.S. GAAP, oil and gas sales are presented net of royalties in our Interim Financial Statements. Under IFRS, industry standard is to present oil and gas sales before deduction of royalties and as such this MD&A presents production, oil and gas sales, and BOE measures on this basis to remain comparable with our peers.

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 U.S. GAAP and therefore may not be comparable with the calculation of similar measures by other entities:

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

"Funds Flow" is used to analyze operating performance, leverage and liquidity. Funds flow is calculated as net cash provided by operating activities but before asset retirement obligation expenditures and changes in non-cash operating working capital.

	Three months ended June 30,		Six months ended June 30,	
Reconciliation of Cash Flow from Operating Activities to Funds Flow	**2014**	**2013**	**2014**	**2013**
Cash flow from operating activities	$ 228,506	$ 195,424	$ 368,916	$ 356,658
Asset retirement obligation expenditures	4,240	2,957	8,532	6,335
Changes in non-cash operating working capital	(19,535)	6,325	56,275	14,312
Funds flow	$ 213,211	$ 204,706	$ 433,723	$ 377,305

"Debt to Funds Flow Ratio" is used to analyze leverage and liquidity. The debt to funds flow ratio is calculated as total debt net of cash, divided by a trailing 12 months of funds flow.

"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 Dividend Program ("SDP") proceeds, plus capital spending (including office capital) divided by funds flow.

OVERVIEW

Our strong operational performance continued during the second quarter with production of 103,987 BOE/day, up 15% from the same period a year ago and up 5% from the prior quarter. Based on our year to date performance, we have increased our annual production guidance to 100,000-104,000 BOE/day from 96,000-100,000 BOE/day and are on track to deliver approximately 5% crude oil and liquids growth, with production of 44,000 bbls/day. Our capital program remained on track with spending of $204.4 million during the quarter and we are maintaining our capital spending guidance for 2014 of $800 million. With the strength of our balance sheet and the anticipated proceeds from our non-core divestments, we are evaluating opportunities to modestly increase spending in our core areas and plan to review spending levels in the third quarter.

Funds flow in the second quarter totaled $213.2 million compared to $204.7 million in the same period in 2013 and $220.5 million in the first quarter of 2014. The decrease in funds flow compared to the first quarter of 2014 was primarily a result of lower natural gas prices and a wider Marcellus differential to NYMEX, offset by higher crude oil prices. Operating costs and cash general and administrative costs came in better than expected at $10.09/BOE and $1.97/BOE, respectively, and as a result we are lowering our 2014 guidance for operating costs and cash general and administrative to $10.10/BOE (from $10.25/BOE) and $2.30/BOE (from $2.45/BOE). Our share price rose by approximately $4.80 or 22% during the second quarter, which led to an increase in our cash share-based compensation expense. Accordingly, we are increasing our cash share-based compensation guidance to $0.60/BOE from $0.45/BOE.

We continue to maintain our financial flexibility and strong balance sheet. Our trailing 12 month debt to funds flow ratio was 1.3x and we had $706.7 million of undrawn credit capacity at quarter end. In June, we signed agreements and priced a US$200.0 million private placement of senior unsecured notes with a ten year average life and an interest rate of 3.79%. The debt issue is expected to close in early September and proceeds will be used to repay outstanding debt.

RESULTS OF OPERATIONS

Production

Production increased by 5% to 103,987 BOE/day in the second quarter of 2014 from 98,821 BOE/day in the first quarter. Crude oil volumes grew by 6% due to our ongoing development program in Fort Berthold, while natural gas volumes rose by 5% as a result of the strong performance of our Marcellus assets.

Compared to the second quarter of 2013, production increased 15% or 13,950 BOE/day. Natural gas volumes grew by approximately 25% due to our ongoing development activity in the Marcellus, along with the December 2013 acquisition of additional working interests in our existing Marcellus properties. Over the same period, our crude oil volumes increased by approximately 5% due to growth in our Fort Berthold production volumes and despite divestments of approximately 2,100 BOE/day of non-core Canadian crude oil production in the second half of 2013.

Our production mix was unchanged from the previous quarter, with natural gas accounting for 58% of production and crude oil and liquids making up 42% of production.

Average daily production volumes for the three and six months ended June 30, 2014 and 2013 are outlined below:

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2014**	**2013**	**% Change**	**2014**	**2013**	**% Change**
Crude oil (bbls/day)	39,863	38,066	5%	38,817	38,193	2%
Natural gas liquids (bbls/day)	3,636	3,497	4%	3,450	3,546	(3)%
Natural gas (Mcf/day)	362,929	290,841	25%	354,906	281,275	26%
Total daily sales (BOE/day)	103,987	90,037	15%	101,418	88,618	14%

As a result of strong operational performance, we are increasing our annual average production guidance to 100,000-104,000 BOE/day from 96,000-100,000 BOE/day, with crude oil and natural gas liquids expected to contribute approximately 44,000 bbls/day. This revised production guidance assumes anticipated divestments of non-core gas weighted properties in Canada with production of approximately 2,500 to 3,500 BOE/day in the fourth quarter.

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 the six month period ended June 30, 2014 and 2013 and quarterly average prices from the second quarter of 2014 to the second quarter of 2013.

	Six months ended June 30,						
Pricing (average for the period)	**2014**	**2013**	**Q2 2014**	**Q1 2014**	**Q4 2013**	**Q3 2013**	**Q2 2013**
Benchmarks							
WTI crude oil (US$/bbl)	$ 100.84	$ 94.30	$ 102.99	$ 98.68	$ 97.46	$ 105.82	$ 94.22
AECO natural gas – monthly index (CDN$/Mcf)	4.72	3.34	4.68	4.76	3.16	2.82	3.59
AECO natural gas – daily index (CDN$/Mcf)	5.20	3.37	4.69	5.71	3.53	2.43	3.53
NYMEX natural gas – last day (US$/Mcf)	4.80	3.71	4.67	4.94	3.60	3.58	4.09
US/CDN exchange rate	1.10	1.02	1.09	1.10	1.05	1.04	1.02
Enerplus selling price[(1)]							
Crude oil (CDN$/ bbl)	$ 93.25	$ 80.74	$ 94.90	$ 91.48	$ 77.77	$ 96.30	$ 82.95
Natural gas liquids (CDN$/ bbl)	57.66	52.16	49.98	66.30	54.26	49.88	45.64
Natural gas (CDN$/ Mcf)	4.46	3.41	4.02	4.93	3.26	2.96	3.70
Average differentials (US$/bbl or US$/Mcf)							
MSW Edmonton – WTI	$ (7.19)	$ (5.31)	$ (6.13)	$ (8.25)	$ (14.93)	$ (4.72)	$ (3.67)
WCS Hardisty – WTI	(21.59)	(25.56)	(20.04)	(23.13)	(32.20)	(17.48)	(19.16)
Brent Futures (ICE) – WTI	7.97	13.69	6.75	9.19	11.86	3.83	9.14
AECO monthly – NYMEX	(0.50)	(0.43)	(0.38)	(0.63)	(0.60)	(0.86)	(0.58)
Enerplus realized differentials[(1)]							
Canada crude oil – WTI	$ (19.19)	$ (22.03)	$ (17.80)	$ (20.70)	$ (30.73)	$ (15.18)	$ (16.97)
Canada natural gas – NYMEX	(0.51)	(0.62)	(0.71)	(0.31)	(0.63)	(1.06)	(0.78)
Bakken crude oil – WTI	$ (12.87)	$ (7.89)	$ (14.55)	(11.85)	(17.47)	(11.41)	(9.61)
Marcellus natural gas – NYMEX	(1.20)	(0.11)	(1.50)	(0.88)	(0.50)	(0.52)	(0.12)

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

Crude Oil and Natural Gas Liquids

WTI prices increased by 4% during the second quarter of 2014 due to elevated tensions in the Middle East and decreased U.S. storage levels as refiners ran at high utilization rates. In particular, balances at Cushing, the WTI pricing hub, decreased significantly during the quarter due to increased take away. The market rallied strongly in June on fears of a potential supply disruption in Iraq, driving spot WTI prices to reach an intra-day high of US$107.73/bbl.

Crude oil differentials in Canada improved in the second quarter, with WCS averaging US$20.04/bbl below WTI and light sweet differentials averaging US$6.13/bbl below WTI. The improvement in differentials was largely due to scheduled maintenance by oil sands producers that restricted production during the period. We expect that incremental downstream pipeline capacity coming into service in the second half of 2014 will help support Canadian differential prices for the remainder of the year. Our realized differential for Canadian crude oil improved during the second quarter averaging US$17.80/bbl below WTI compared to US$20.70/bbl in the first quarter.

Our average realized Bakken differential widened during the quarter, to US$14.55/bbl below WTI from US$11.85/bbl in the first quarter, as our volumes being shipped by rail grew during the quarter and rail netbacks fell.

Natural Gas

U.S. natural gas prices weakened throughout the second quarter as injections into storage facilities were much higher compared to the same period in 2013 due to cooler than normal weather conditions across much of the key U.S. demand centres. In Canada, AECO differentials to NYMEX narrowed to US$0.38/Mcf below NYMEX during the second quarter compared to US$0.63/Mcf in the first quarter.

We continue to maintain a balanced mix of AECO basis, month and day index price exposures in our Canadian gas portfolio, with our index exposure split almost evenly between month and day AECO indices. During the first quarter, our realized differentials were positively impacted by the volatility of the AECO daily index, while the second quarter saw no material differences between AECO month and day index.

Natural gas prices in the Marcellus weakened considerably in the second quarter as cooler temperatures resulted in lower than expected demand for gas-fired power generation. When combined with an estimated net supply increase of over 1.5 Bcf/day in the Northeast U.S. relative to last year, regional spot price differentials to NYMEX in the Marcellus widened from an average of approximately US$0.88/Mcf below NYMEX in April to as much as US$2.30/Mcf below NYMEX in June. Approximately 56% of our Marcellus production during the quarter was exposed to these regional spot prices contributing to our realized Marcellus price differential of US$1.50/Mcf below NYMEX for the quarter. We now expect an annual realized Marcellus price differential of US$1.35/Mcf below NYMEX for 2014.

Foreign Exchange

The majority of our oil and gas sales are based on U.S. dollar denominated indices, and a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. Following a rapid depreciation of the Canadian dollar in the first quarter of 2014, the dollar regained some ground in the second quarter supported by higher oil prices and rising inflation. After reaching a low of 1.1251 near the close of the first quarter, the Canadian dollar rose to 1.0676 at June 30, 2014. As the dollar weakened in the first quarter, we entered into costless collars on our oil and gas sales to protect a portion of our anticipated revenues at favorable exchange rates.

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. We have increased our crude oil hedges significantly since last quarter. As of July 23, 2014 we have swapped an average of 21,000 bbls/day from July 1, 2014 to December 31, 2014 at an average price of US$95.42/bbl, which represents approximately 68% of our forecasted net crude oil production after royalties. For the first half of 2015, we have swapped 15,500 bbls/day at an average price of US$93.58/bbl, which represents approximately 50% of our forecasted net crude oil production after royalties. Additionally, we have 8,000 bbls/d swapped for the second half of 2015 at an average price of US$93.86/bbl, which represents approximately 26% of our forecasted net crude oil production after royalties.

We have entered into WCS differential swap positions for 2014 to manage our exposure to widening heavy crude oil differentials. These differential swaps have been fixed at an average price of WTI less a fixed spread of US$21.00/bbl on 3,000 bbls/day from July through September of 2014 and 4,000 bbls/day from October through December of 2014. We have also entered into 3,000 bbl/day of Brent-WTI differential swap positions for the remainder of 2014 to shift some of our WTI price exposure to Brent based pricing, selling WTI at an average of 92.63% of Brent pricing.

As of July 23, 2014 we have downside protection on approximately 50% of our forecasted natural gas production after royalties for the remainder of 2014 consisting of NYMEX swaps at US$4.14/Mcf on 28% of production, NYMEX collars at US$4.30 – $5.08/Mcf on 11% of production and AECO swaps at an average price of $4.25/Mcf on 11% of production. Overall for 2015, we have downside protection on approximately 23% of our forecasted annual natural gas production after royalties comprised of NYMEX swaps at an average price of US$4.26/Mcf on 20% of production and NYMEX collars in the first quarter at US$4.53 -$5.53/Mcf on 3% of forecasted annual production.

We have foreign exchange costless collars in place to hedge a floor exchange rate on a portion of our U.S. dollar denominated oil and gas sales and to participate in some upside potential in the event the Canadian dollar continues to weaken. As of July 23, 2014 we have US$12.0 million per month hedged for the remainder of 2014 at an average USD/CDN floor of 1.1046, ceiling of 1.1558 and conditional ceiling of 1.1198. Under these contracts, if the monthly foreign exchange rate settles above the ceiling rate the conditional ceiling is used to determine the settlement amount. For 2015, we have US$12.0 million per month hedged at an average USD/CDN floor of 1.1083, ceiling of 1.1900 and conditional ceiling of 1.1254. During the second quarter, we recorded cash gains of $0.4 million and non-cash mark-to-market gains of $6.7 million on the contracts.

The following is a summary of our financial contracts in place at July 23, 2014 expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)[1]				AECO Natural Gas (CDN$/Mcf)[1]	NYMEX Natural Gas (US$/Mcf)[1]			
	Jul 1, 2014 – Sep 30, 2014	Oct 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Dec 31, 2015	Jul 1, 2014 – Dec 31, 2014	Jul 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Mar 31, 2015	Apr 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Dec 31, 2015
Purchased Puts	–	–	–	–	–	$ 4.30	$ 4.53	–	–
%	–	–	–	–	–	11%	11%	–	–
Sold Puts	–	–	–	–	–	$ 3.23	–	–	–
%	–	–	–	–	–	9%	–	–	–
Swaps	$ 95.54	$ 95.29	$ 93.58	$ 93.86	$ 4.25	$ 4.14	$ 4.31	$ 4.31	$ 4.21
%	71%	65%	50%	26%	11%	28%	24%	24%	17%
Sold Calls	–	–	–	–	–	$ 5.04	$ 5.53	–	–
%	–	–	–	–	–	20%	11%	–	–
Purchased Calls	–	–	–	–	–	$ 4.17	–	–	–
%	–	–	–	–	–	9%	–	–	–

(1) Based on weighted average price (before premiums), assumed average annual production of 100,000 – 104,000 BOE/day for 2014 and 2015, less royalties and production taxes of 23% in aggregate.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Risk Management Gains/(Losses) ($ millions)	Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
Cash gains/(losses):				
Crude oil	$ (21.2)	$ 11.0	$ (32.0)	$ 21.9
Natural gas	(3.3)	(1.9)	(7.9)	(1.2)
Total cash gains/(losses)	$ (24.5)	$ 9.1	$ (39.9)	$ 20.7
Non-cash gains/(losses):				
Change in fair value – crude oil	$ (24.8)	$ 8.7	$ (34.2)	$ (20.9)
Change in fair value – natural gas	5.3	12.8	(2.6)	3.8
Total non-cash gains/(losses)	$ (19.5)	$ 21.5	$ (36.8)	$ (17.1)
Total gains/(losses)	$ (44.0)	$ 30.6	$ (76.7)	$ 3.6

(Per BOE)	Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
Total cash gains/(losses)	$ (2.60)	$ 1.11	$ (2.17)	$ 1.29
Total non-cash gains/(losses)	(2.06)	2.63	(2.01)	(1.07)
Total gains/(losses)	$ (4.66)	$ 3.74	$ (4.18)	$ 0.22

During the second quarter of 2014, we realized cash losses of $21.2 million on our crude oil contracts and $3.3 million on our natural gas contracts. In comparison, during the second quarter of 2013, we realized cash gains of $11.0 million on our crude oil contracts and cash losses of $1.9 million on our natural gas contracts. The cash losses realized in 2014 were a result of crude oil and natural gas prices rising above our fixed price swap positions. The crude oil cash gains in 2013 were due to contracts that provided floor protection above market prices.

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as 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 second quarter of 2014 the fair value of our crude oil and natural gas contracts represented net loss positions of $49.0 million and $2.3 million, respectively. For the three and six months ended June 30, 2014 the change in the fair value of our crude oil contracts represented losses of $24.8 million and $34.2 million, respectively, while the change in fair value of our natural gas contracts represented a gain of $5.3 million and a loss of $2.6 million, respectively.

Revenues

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Oil and natural gas sales	$ 504.5	$ 404.8	$ 999.5	$ 778.2
Royalties	(89.6)	(63.5)	(176.9)	(123.5)
Oil and natural gas sales, net of royalties	$ 414.9	$ 341.3	$ 822.6	$ 654.7

Oil and natural gas sales were $504.5 million in the second quarter of 2014, an increase of 25% or $99.7 million compared to the same period in 2013. For the six months ended June 30, 2014 oil and natural gas sales were $999.5 million, an increase of 28% or $221.3 million compared to the same period a year ago. The increase in revenues was related to higher production and improved realized prices.

Royalties and Production Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Royalties	$ 89.6	$ 63.5	$ 176.9	$ 123.5
Production taxes	20.0	17.9	39.8	32.5
Royalties and production taxes	$ 109.6	$ 81.4	$ 216.7	$ 156.0
As a % of oil and natural gas sales, net of transportation	22%	20%	22%	20%

	Three months ended June 30,		Six months ended June 30,	
(Per BOE)	2014	2013	2014	2013
Royalties	$ 9.47	$ 7.75	$ 9.64	$ 7.70
Production taxes	2.11	2.18	2.17	2.03
Royalties and production taxes	$ 11.58	$ 9.93	$ 11.81	$ 9.73
As a % of oil and natural gas sales, net of transportation	22%	20%	22%	20%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. During the three and six months ended June 30, 2014 royalties and production taxes increased to $109.6 million and $216.7 million, respectively, from $81.4 million and $156.0 million for the same period a year ago. This upward trend is primarily due to higher realized prices and increased production from higher royalty rate U.S. properties. Royalties and production taxes averaged 22% of oil and gas sales (net of transportation) in 2014 compared to 20% in 2013.

We expect an average royalty and production tax rate of 23% in 2014.

Operating Expenses

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2014	2013	2014	2013
Operating Expenses	$ 95.5	$ 85.4	$ 184.6	$ 166.7
Per BOE	$ 10.09	$ 10.42	$ 10.06	$ 10.39

Our operating expenses for the three and six months ended June 30, 2014 were $95.5 million or $10.09/BOE and $184.6 million or $10.06/BOE respectively. In comparison, we had operating costs of $85.4 million or $10.42/BOE and $166.7 million or $10.39/BOE for the same periods in 2013. The current year operating costs have decreased on a per BOE basis mainly due to the higher production from our lower cost Marcellus and Fort Berthold properties.

Based on our increased production guidance and continued focus on cost control, we are reducing our annual guidance for operating costs to $10.10/BOE from $10.25/BOE.

Transportation Costs

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2014	2013	2014	2013
Transportation costs	$ 13.1	$ 6.2	$ 26.2	$ 13.4
Per BOE	$ 1.39	$ 0.76	$ 1.43	$ 0.84

Transportation costs for the three and six months ended June 30, 2014 were $13.1 million and $26.2 million, respectively, compared to $6.2 million and $13.4 million for the same periods in 2013. The increase from the prior year was related to higher U.S. production as well as costs associated with securing U.S. pipeline capacity.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three and six months ended June 30, 2014 and 2013. 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. Certain prior period amounts have been reclassified to conform with current period presentation.

	Three months ended June 30, 2014		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	44,681 BOE/day	355,836 Mcfe/day	103,987 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[(2)]	$ 86.94	$ 4.26	$ 51.93
Royalties and production taxes	(21.06)	(0.74)	(11.58)
Cash operating costs	(13.17)	(1.30)	(10.12)
Netback before hedging	$ 52.71	$ 2.22	$ 30.23
Cash gains/(losses)	(5.23)	(0.10)	(2.60)
Netback after hedging	$ 47.48	$ 2.12	$ 27.63
Netback before hedging ($ millions)	$ 214.4	$ 71.7	$ 286.1
Netback after hedging ($ millions)	$ 193.1	$ 68.4	$ 261.5

Netbacks by Property Type	Three months ended June 30, 2013 Crude Oil	Natural Gas	Total
Average Daily Production	42,753 BOE/day	283,704 Mcfe/day	90,037 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 75.70	$ 4.03	$ 48.65
Royalties and production taxes	(17.13)	(0.57)	(9.93)
Cash operating costs	(13.19)	(1.36)	(10.55)
Netback before hedging	$ 45.38	$ 2.10	$ 28.17
Cash gains/(losses)	2.82	(0.07)	1.11
Netback after hedging	$ 48.20	$ 2.03	$ 29.28
Netback before hedging ($ millions)	$ 176.6	$ 54.2	$ 230.8
Netback after hedging ($ millions)	$ 187.5	$ 52.4	$ 239.9

Netbacks by Property Type	Six months ended June 30, 2014 Crude Oil	Natural Gas	Total
Average Daily Production	43,519 BOE/day	347,394 Mcfe/day	101,418 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 86.29	$ 4.67	$ 53.03
Royalties and production taxes	(21.19)	(0.79)	(11.81)
Cash operating costs	(13.28)	(1.28)	(10.07)
Netback before hedging	$ 51.82	$ 2.60	$ 31.15
Cash gains/(losses)	(4.05)	(0.13)	(2.17)
Netback after hedging	$ 47.77	$ 2.47	$ 28.98
Netback before hedging ($ millions)	$ 408.2	$ 163.6	$ 571.8
Netback after hedging ($ millions)	$ 376.2	$ 155.7	$ 531.9

Netbacks by Property Type	Six months ended June 30, 2013 Crude Oil	Natural Gas	Total
Average Daily Production	42,684 BOE/day	275,604 Mcfe/day	88,618 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 74.25	$ 3.83	$ 47.68
Royalties and production taxes	(16.70)	(0.54)	(9.73)
Cash operating costs	(13.01)	(1.36)	(10.48)
Netback before hedging	$ 44.54	$ 1.93	$ 27.47
Cash gains/(losses)	2.83	(0.02)	1.29
Netback after hedging	$ 47.37	$ 1.91	$ 28.76
Netback before hedging ($ millions)	$ 344.1	$ 96.5	$ 440.6
Netback after hedging ($ millions)	$ 366.0	$ 95.3	$ 461.3

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

Our crude oil properties accounted for 71% of our corporate netback before hedging for the year to date compared to 78% for the same period in 2013. Crude oil netbacks per BOE increased for the three and six months ended June 30, 2014 compared to the same periods in 2013 primarily due to higher realized crude oil prices partially offset by higher royalties as a result of increased U.S. production. Natural gas netbacks per Mcfe decreased slightly during the second quarter compared to the same period last year due to weakened gas prices and widening differentials. Strong gas prices in the first quarter led to an increase in the natural gas netback for the six months ended June 30, 2014 compared to the same period in 2013.

General and Administrative Expenses ("G&A")

Total G&A expenses include cash G&A expenses as well as share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans") and our stock option plan. SBC charges are dependent on our share price and can fluctuate from period to period.

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Cash:				
G&A expense[1]	$ 18.7	$ 18.8	$ 39.2	$ 43.5
SBC	10.7	3.7	17.5	9.2
Non-Cash:				
SBC	3.5	3.0	6.5	5.5
SBC – equity swap loss/(gain)	(4.7)	(0.8)	(5.9)	(2.3)
Total G&A expenses	$ 28.2	$ 24.7	$ 57.3	$ 55.9

	Three months ended June 30,		Six months ended June 30,	
(Per BOE)	2014	2013	2014	2013
Cash:				
G&A expense[1]	$ 1.97	$ 2.29	$ 2.14	$ 2.71
SBC	1.12	0.45	0.95	0.57
Non-Cash:				
SBC	0.37	0.36	0.35	0.34
SBC – equity swap loss/(gain)	(0.49)	(0.09)	(0.32)	(0.14)
Total G&A expenses	$ 2.97	$ 3.01	$ 3.12	$ 3.48

(1) Excluding SBC.

Cash G&A expenses during the second quarter were in line with our expectations at $18.7 million or $1.97/BOE compared to $18.8 million or $2.29/BOE in the second quarter of 2013. For the six months ended June 30, 2014 cash G&A expenses were $39.2 million or $2.14/BOE compared to $43.5 million or $2.71/BOE for the same period in 2013. The decrease during 2014 was mainly due to one-time charges recorded in the prior year associated with the departure of personnel. Higher production volumes in 2014 have also helped to decrease our reported G&A on a per BOE basis.

Cash SBC expense increased during 2014 due to the increase in our share price, which had risen by 39% during the six months ended June 30, 2014. For the second quarter of 2014, cash SBC expense was $10.7 million or $1.12/BOE compared to $3.7 million or $0.45/BOE during the second quarter of 2013. For the six months ended June 30, 2014 cash SBC expense was $17.5 million or $0.95/BOE compared to $9.2 million or $0.57/BOE for the same period in the prior year.

We have hedged a portion of the outstanding cash settled units under our LTI plans at an average price of $14.78/share. As a result of the increase in our share price we recorded non-cash mark-to-market gains of $4.7 million and $5.9 million for the three and six months ended June 30, 2014, respectively.

We are reducing our 2014 guidance for cash G&A expense to $2.30/BOE from $2.45/BOE based on our revised production guidance and continued focus on cost control. We are also increasing our 2014 guidance for cash SBC to $0.60/BOE from $0.45/BOE based on our share price at June 30, 2014.

Interest Expense

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Interest on senior notes and bank facility	$ 16.0	$ 14.3	$ 30.6	$ 28.5
Non-cash interest expense	0.5	0.5	1.1	0.7
Total interest expense	$ 16.5	$ 14.8	$ 31.7	$ 29.2

For the three and six months ended June 30, 2014 we recorded total interest expense of $16.5 million and $31.7 million, respectively, compared to $14.8 million and $29.2 million in the same periods in 2013. Despite a decreasing debt balance, interest on our senior notes increased slightly year over year due to the impact of a weaker Canadian dollar on our U.S. dollar denominated interest payments.

Non-cash amounts recorded in interest expense include unrealized gains and losses resulting from the change in fair value of the interest component of our cross currency interest rate swap ("CCIRS") and amortization of deferred financing charges.

At June 30, 2014, after including our underlying derivatives, approximately 72% of our debt was based on fixed interest rates and 28% on floating interest rates.

Foreign Exchange

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Realized loss/(gain)	$ 16.6	$ 14.9	$ 16.7	$ 17.6
Unrealized loss/(gain)	(23.8)	(12.7)	(22.5)	(11.1)
Total foreign exchange loss/(gain)	$ (7.2)	$ 2.2	$ (5.8)	$ 6.5

We recorded a net foreign exchange gain of $7.2 million during the second quarter and a gain of $5.8 million year to date, compared to net losses of $2.2 million and $6.5 million during the same periods in 2013.

On June 19, 2014 we made the final US$35.0 million principal repayment on our US$175.0 million senior notes and corresponding CCIRS settlement, which resulted in a $15.8 million realized foreign exchange loss. The remaining realized losses during the quarter related to day-to-day transactions denominated in foreign currencies.

Unrealized foreign exchange gains in the quarter related to the translation of our U.S. dollar debt and working capital and the reversal of cumulative mark-to-market losses on the final settlement of our CCIRS.

Capital Investment and Dispositions

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Capital spending	$ 204.4	$ 139.7	$ 422.2	$ 312.6
Office capital	1.2	0.8	1.6	2.2
Sub-total	$ 205.6	$ 140.5	$ 423.8	$ 314.8
Property and land acquisitions	$ 3.2	$ 51.7	$ 13.2	$ 55.7
Property dispositions	0.5	(71.3)	(116.7)	(72.6)
Sub-total	$ 3.7	$ (19.6)	$ (103.5)	$ (16.9)
Total net capital investment	$ 209.3	$ 120.9	$ 320.3	$ 297.9

Capital spending for the second quarter totaled $204.4 million compared to $139.7 million during the same period in 2013. We continue to focus our spending on our core development areas. Crude oil spending for the quarter included $98.6 million at Fort Berthold and $28.1 million on our Canadian waterflood properties. Natural gas spending included $45.1 million in the Marcellus and $31.0 million on our Deep Basin assets.

We completed minor property and land acquisitions totaling $3.2 million during the quarter. In the second quarter of 2013 we spent $51.7 million, which included $34.0 million for the acquisition of an incremental 50% working interest in our Pouce Coupe light oil waterflood property as well as $16.7 million on land acquisitions around our existing acreage in the U.S.

Property dispositions of $71.3 million in the second quarter of 2013 included the sale of our Taylorton and Turner Valley non-core oil asset for proceeds of $57.2 million along with other minor dispositions totaling $14.1 million.

We are maintaining our capital spending guidance at $800 million. However, given the strength of our balance sheet and anticipated divestment proceeds, we are evaluating opportunities in our core areas and may modestly increase spending in the second half of the year.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2014	2013	2014	2013
DDA&A expense	$ 148.7	$ 160.5	$ 280.8	$ 306.7
Per BOE	$ 15.71	$ 19.59	$ 15.30	$ 19.12

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three and six months ended June 30, 2014 DDA&A decreased to $148.7 million and $280.8 million, respectively, compared to $160.5 million and $306.7 million during the same periods in 2013. The decrease was primarily due to significant reserve additions for the year ended December 31, 2013 that lowered our depletion rate in 2014.

Asset Retirement Obligation

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are estimated by Enerplus based on our net ownership interest, anticipated costs to abandon and reclaim and the timing of the costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation to be $288.6 million at June 30, 2014 compared to $291.8 million at December 31, 2013.

Income Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Current tax expense	$ 3.8	$ 1.4	$ 11.5	$ 2.7
Deferred tax expense	12.7	20.3	37.2	22.2
Total tax expense	$ 16.5	$ 21.7	$ 48.7	$ 24.9

We recorded total tax expense of $16.5 million and $48.7 million for the three and six months ended June 30, 2014, respectively, compared to $21.7 million and $24.9 million for the same periods in 2013. For the three months ended June 30, 2014 the decrease in total tax expense relates primarily to the decrease in net income for tax purposes. For the six months ended June 30, 2014 higher revenues caused net income for tax purposes to increase resulting in an increase in tax expense.

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. Based on current commodity prices and assuming no acquisition and divestment activity, we expect to pay U.S. cash taxes of between 3% to 5% of our U.S. funds flow for 2014 and 2015. We expect to continue to pay U.S. AMT through 2018 with the rate gradually increasing to approximately 15% over that time. We currently do not expect to pay material cash taxes in Canada until after 2018.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

The following table provides a geographical split of key operating and financial results for the three and six months ended June 30, 2014 and 2013.

	Three months ended June 30, 2014			Three months ended June 30, 2013		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	17,184	22,679	39,863	18,364	19,702	38,066
Natural gas liquids (bbls/day)	2,476	1,160	3,636	2,975	522	3,497
Natural gas (Mcf/day)	156,401	206,528	362,929	186,569	104,272	290,841
Total average daily production (BOE/day)	45,727	58,260	103,987	52,434	37,603	90,037
Pricing[2]						
Crude oil (per bbl)	$ 92.90	$ 96.41	$ 94.90	$ 79.06	$ 86.58	$ 82.95
Natural gas liquids (per bbl)	57.01	35.00	49.98	49.05	26.21	45.64
Natural gas (per Mcf)	4.32	3.80	4.02	3.39	4.26	3.70
Capital Expenditures						
Capital spending	$ 60.4	$ 144.0	$ 204.4	$ 44.4	$ 95.3	$ 139.7
Acquisitions	–	3.2	3.2	35.0	16.7	51.7
Dispositions	–	0.5	0.5	(63.9)	(7.4)	(71.3)
Netback Before Hedging						
Oil and natural gas sales	$ 226.0	$ 278.5	$ 504.5	$ 208.9	$ 195.9	$ 404.8
Royalties	(35.1)	(54.5)	(89.6)	(25.5)	(38.0)	(63.5)
Operating expense	(62.2)	(33.5)	(95.7)	(64.9)	(21.5)	(86.4)
Production taxes	(1.9)	(18.1)	(20.0)	(5.0)	(12.9)	(17.9)
Transportation expense	(5.9)	(7.2)	(13.1)	(5.4)	(0.8)	(6.2)
Netback before hedging	$ 120.9	$ 165.2	$ 286.1	$ 108.1	$ 122.7	$ 230.8
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 44.0	$ –	$ 44.0	$ 30.6	–	$ 30.6
General and administrative expense	22.6	5.6	28.2	21.1	3.6	24.7
Current income tax expense/(recovery)	(0.2)	4.0	3.8	0.1	1.3	1.4

(1) Company interest volumes.

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

(CDN$ millions, except per unit amounts)	Six months ended June 30, 2014 Canada	U.S.	Total	Six months ended June 30, 2013 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	16,882	21,935	38,817	18,764	19,429	38,193
Natural gas liquids (bbls/day)	2,508	942	3,450	3,045	501	3,546
Natural gas (Mcf/day)	154,027	200,879	354,906	182,214	99,061	281,275
Total average daily production (BOE/day)	45,061	56,357	101,418	52,178	36,440	88,618
Pricing[2]						
Crude oil (per bbl)	$ 89.55	$ 96.09	$ 93.25	$ 73.44	$ 87.80	$ 80.74
Natural gas liquids (per bbl)	63.16	43.01	57.66	55.81	30.02	52.16
Natural gas (per Mcf)	4.70	4.28	4.46	3.15	3.90	3.41
Capital Expenditures						
Capital spending	$ 188.0	$ 234.2	$ 422.2	$ 127.4	$ 185.2	$ 312.6
Acquisitions	–	13.2	13.2	37.6	18.1	55.7
Dispositions	(67.7)	(49.0)	(116.7)	(65.2)	(7.4)	(72.6)
Netback Before Hedging						
Oil and natural gas sales	$ 446.0	$ 553.5	$ 999.5	$ 397.1	$ 381.1	$ 778.2
Royalties	(69.1)	(107.8)	(176.9)	(50.4)	(73.1)	(123.5)
Operating expense	(124.4)	(60.4)	(184.8)	(131.4)	(36.8)	(168.2)
Production taxes	(3.9)	(35.9)	(39.8)	(6.4)	(26.1)	(32.5)
Transportation expense	(11.7)	(14.5)	(26.2)	(11.8)	(1.6)	(13.4)
Netback before hedging	$ 236.9	$ 334.9	$ 571.8	$ 197.1	$ 243.5	$ 440.6
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 76.7	$ –	$ 76.7	$ 3.6	$ –	$ 3.6
General and administrative expense	45.9	11.4	57.3	49.0	6.9	55.9
Current income tax expense/(recovery)	(0.4)	11.9	11.5	0.1	2.6	2.7

(1) Company interest volumes.
(2) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.

QUARTERLY FINANCIAL INFORMATION

(CDN$ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Diluted
2014				
Second Quarter	$ 414.9	$ 40.0	$ 0.20	$ 0.19
First Quarter	407.7	40.0	0.20	0.19
Total	$ 822.6	$ 80.0	$ 0.39	$ 0.39
2013				
Fourth Quarter	$ 332.4	$ 29.6	$ 0.15	$ 0.15
Third Quarter	365.4	(3.7)	(0.02)	(0.02)
Second Quarter	341.3	38.5	0.19	0.19
First Quarter	313.4	(16.4)	(0.08)	(0.08)
Total	$ 1,352.5	$ 48.0	$ 0.24	$ 0.24
2012				
Fourth Quarter	$ 310.2	$ 34.6	$ 0.18	$ 0.18
Third Quarter	279.3	(88.6)	(0.45)	(0.45)
Second Quarter	274.3	(41.9)	(0.21)	(0.21)
First Quarter	289.5	(174.8)	(0.92)	(0.92)
Total	$ 1,153.3	$ (270.7)	$ (1.38)	$ (1.38)

Oil and gas sales increased in the second quarter of 2014 due to higher production volumes which were partially offset by lower realized natural gas prices compared to the first quarter. Oil and gas sales grew during 2013 with increasing production volumes. Net income grew in 2014 compared to 2013 from increased production and realized prices. Net income in 2012 was lower due to asset impairments recorded during the year.

LIQUIDITY AND CAPITAL RESOURCES

We continued to maintain a strong balance sheet and ample liquidity through the second quarter. At June 30, 2014 we had a conservative trailing 12 month debt to cash flow ratio of 1.3x and approximately $706.7 million of undrawn credit capacity. On June 19, 2014 we made the final principal payment on our US$175.0 million senior notes and the related CCIRS settlement. During the quarter, we entered into agreements to issue US$200.0 million of senior unsecured notes on a private placement basis. The notes, which are expected to close on September 3, 2014, have a twelve year amortizing term with a ten year average life and a fixed interest rate of 3.79%. We plan to use the proceeds to repay our short-term, floating interest rate bank debt.

Our adjusted payout ratio, calculated as dividends (net of SDP proceeds) plus capital and office spending, divided by funds flow, increased to 120% and 119% for the three and six months ended June 30, 2014, respectively, compared to 89% and 106% for the same periods in 2013. Although funds flow increased by 4% and 15% for the three and six months ended June 2014 compared to the same periods in 2013, we saw a proportionately larger increase in our capital spending program and a decrease in our SDP participation over the same period.

Total debt net of cash at June 30, 2014 was $1,067.6 million, including current portion, compared to $1,022.3 million at December 31, 2013. Total debt was comprised of $293.3 million of bank indebtedness and $776.3 million of senior notes, less $2.0 million in cash. Our working capital deficiency, excluding cash and current deferred financial and tax assets and credits, increased slightly during the quarter to $251.2 million from $226.1 million. Although receivables increased due to higher production levels, this was offset by a higher current portion of long-term debt related to senior note maturities in June of 2015. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our key leverage ratios are detailed below:

Financial Leverage and Coverage	June 30, 2014	December 31, 2013
Long-term debt to funds flow (trailing 12-month)(1)	1.3 x	1.4 x
Funds flow to interest expense (trailing 12-month)(2)	13.8 x	13.3 x
Long-term debt to long-term debt plus equity(1)	35%	35%

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

At June 30, 2014 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

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per share amounts)	2014	2013	2014	2013
Cash dividends	$ 50.5	$ 42.6	$ 92.7	$ 86.3
Stock dividend plan	4.7	11.4	17.4	21.5
Total dividends to shareholders	$ 55.2	$ 54.0	$ 110.1	$ 107.8
Per weighted average share (Basic)	$ 0.27	$ 0.27	$ 0.54	$ 0.54

During the three and six months ended June 30, 2014 we recorded dividends to our shareholders of $55.2 million ($0.27/share) and $110.1 million ($0.54/share), respectively, compared to $54.0 million ($0.27/share) and $107.8 million ($0.54/share) for the same periods in 2013. For the first six months of 2014, dividend payments including SDP amounted to 25% of our funds flow of $433.7 million. We will 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 to our dividend at this time.

Participation in the SDP is optional allowing our shareholders to continue to receive cash dividends unless they elect to receive stock dividends. As a result of our improved sustainability and strong balance sheet, in April of this year we eliminated the 5% discount with the intention of reducing shareholder dilution. Subsequently, our participation rate in the SDP decreased significantly to approximately 9% where we had previously been averaging 23%. Participation in the SDP for July was approximately $1.7 million compared to approximately $4.2 million per month in the first quarter.

Shareholders' Capital

	Six months ended June 30,	
	2014	2013
Share capital ($ millions)	$ 3,102.2	$ 3,019.2
Common shares outstanding (thousands)	204,768	200,268
Weighted average shares outstanding – basic (thousands)	203,671	199,430
Weighted average shares outstanding – diluted (thousands)	207,563	199,586

During the second quarter of 2014, a total of 929,000 shares (2013 – 805,000) and $17.8 million of additional equity (2013 – $11.4 million) was issued pursuant to the SDP and the stock option plan. For the six months ended June 30, 2014, a total of 2,010,000 shares (2013 – 1,584,000) and $36.7 million of additional equity (2013 – $21.5 million) was issued pursuant to the SDP and the stock option plan.

At June 30, 2014 we had 204,768,000 shares outstanding (2013 – 200,268,000) and at August 7, 2014 we had 205,229,771 shares outstanding.

U.S. Filing Status

Pursuant to U.S. securities regulations, we are required to reassess our U.S. securities filing status annually at June 30. As at June 30, 2014 we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

2014 GUIDANCE

A summary of our 2014 guidance is below.

Summary of 2014 Expectations	Target
Average annual production	100,000 – 104,000 BOE/day (from 96,000 – 100,000 BOE/day)
Production mix (volumes)	44,000 bbls/day crude oil and liquids 56,000-60,000 BOE/day natural gas
Capital spending	$800 million
Average royalty rate (% of gross sales, net of transportation)	23% (from 23.5%)
Operating costs	$10.10/BOE (from $10.25/BOE)
Cash G&A expenses	$2.30 (from $2.45/BOE)
Cash share-based compensation expenses	$0.60/BOE (from $0.45/BOE)
U.S. Cash taxes (% of U.S. funds flow)	3%-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 June 30, 2014, 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 April 1, 2014 and ending June 30, 2014 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 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 and future production taxes; anticipated cash and non-cash G&A, share-based compensation and financing expenses; operating costs; capital spending levels in 2014 and its impact on our production level; potential future asset impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; 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 and regular U.S. 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 issuances and expected use of proceeds therefrom; and future dispositions and acquisitions, including production volumes associated therewith.*

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 realized prices of Enerplus' products; 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 this 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.