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

The following discussion and analysis of financial results is dated May 8, 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 months ended March 31, 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 and all note references relate to the notes included in the Interim Financial Statements.

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 March 31,	
Reconciliation of Cash Flow from Operating Activities to Funds Flow	**2014**	**2013**
Cash flow from operating activities	$ 140,410	$ 161,234
Asset retirement obligation expenditures	4,292	3,378
Changes in non-cash operating working capital	75,810	7,987
Funds flow	$ 220,512	$ 172,599

"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

Production was strong during the first quarter at 98,821 BOE/day, driven by continued outperformance from our Marcellus natural gas assets. Oil production was essentially flat compared to the fourth quarter of 2013 as weather related delays and third party outages impacted our field operations in both Canada and the U.S. Our natural gas weighting increased to 58% for the quarter given the increase in our natural gas production. Capital spending totaled $217.8 million, slightly less than planned due to weather interruptions that delayed some of our completion activities during the quarter.

First quarter funds flow increased by 28% to $220.5 million from $172.6 million in the same period in 2013. The key drivers for the increase were higher production levels, improved natural gas prices, narrower heavy crude oil differentials and a weaker Canadian dollar, which helps our realized prices. Operating costs and G&A expenses were on target for the quarter. We reported net income of $40.0 million for the quarter, an increase from a net loss of $16.4 million in the first quarter of 2013.

The sustainability of our business continues to strengthen and our balance sheet remains strong. Our adjusted payout ratio decreased to 118% in the first quarter of 2014 from 126% in the same period in 2013. During the quarter we recognized $117.2 million through previously announced non-core property dispositions. At March 31, 2014 we had a conservative trailing twelve month debt to funds flow ratio of 1.3x and approximately $810 million of available capacity on our bank credit facility. Effective April 2014, we elected to eliminate the 5% discount for shares issued under our Stock Dividend Program. This change reflects the improved sustainability of the business and is expected to reduce shareholder dilution.

Our production guidance is unchanged at 96,000 – 100,000 BOE/day however we expect to track towards the high end of the range given Marcellus outperformance. As a result, our natural gas weighting is expected to increase to 56% of total production.

With the weakening of the Canadian dollar against the U.S. dollar and a modest increase in non-operated capital activity, we are increasing our capital spending guidance to $800 million from $760 million. Additionally, based on our current share price performance, we have increased our forecast for cash share-based compensation from $0.25/BOE to $0.45/BOE for 2014. We are maintaining all other guidance targets for 2014.

RESULTS OF OPERATIONS

Production

Production increased by 5% to 98,821 BOE/day compared to the fourth quarter of 2013 and 13% compared to 87,183 BOE/day in the first quarter of 2013. This increase was driven by a 28% increase in natural gas volumes year over year as a result of strong Marcellus well performance along with the purchase of additional working interests in our Marcellus properties at the end of 2013. Crude oil production remained relatively flat from the first quarter of 2013 as higher volumes from our Fort Berthold properties were offset by non-core property dispositions that occurred throughout 2013 as well as weather related production interruptions in 2014.

Given the growth in our natural gas production, our natural gas weighting increased to 58% in the first quarter of 2014 from 56% in the fourth quarter of 2013.

Average daily production volumes for the three months ended March 31, 2014 and 2013 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2014**	**2013**	**% Change**
Crude oil (bbls/day)	37,760	38,321	(1)%
Natural gas liquids (bbls/day)	3,262	3,595	(9)%
Natural gas (Mcf/day)	346,794	271,602	28%
Total daily sales (BOE/day)	98,821	87,183	13%

Our production guidance is unchanged at 96,000 – 100,000 BOE/day however we expect to track towards the high end of the range given Marcellus outperformance. As a result, our natural gas weighting is expected to increase to 56% of total production. This guidance does not contemplate additional acquisitions or dispositions.

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 first quarter of 2013 to the first quarter of 2014:

Pricing (average for the period)	Q1 2014	Q4 2013	Q3 2013	Q2 2013	Q1 2013
Benchmarks					
WTI crude oil (US$/bbl)	$ 98.68	$ 97.46	$ 105.82	$ 94.22	$ 94.37
AECO natural gas – monthly index (CDN$/Mcf)	4.76	3.16	2.82	3.59	3.08
AECO natural gas – daily index (CDN$/Mcf)	5.71	3.53	2.43	3.53	3.20
NYMEX natural gas – last day (US$/Mcf)	4.94	3.60	3.58	4.09	3.34
US/CDN exchange rate	1.10	1.05	1.04	1.02	1.01
Enerplus selling price[1]					
Crude oil (CDN$/ bbl)	$ 91.48	$ 77.77	$ 96.30	$ 82.95	$ 78.52
Natural gas liquids (CDN$/ bbl)	66.30	54.26	49.88	45.64	58.58
Natural gas (CDN$/ Mcf)	4.93	3.26	2.96	3.70	3.10
Average differentials (US$/bbl or US$/Mcf)					
MSW Edmonton – WTI	$ (8.25)	$ (14.93)	$ (4.72)	$ (3.67)	$ (6.95)
WCS Hardisty – WTI	(23.13)	(32.20)	(17.48)	(19.16)	(31.96)
Brent Futures (ICE) – WTI	9.19	11.86	3.83	9.14	18.24
AECO monthly – NYMEX	(0.63)	(0.60)	(0.86)	(0.58)	(0.28)
Enerplus realized differentials[1] (US$/bbl or US$/Mcf)					
Canada crude oil – WTI	$ (20.70)	$ (30.73)	$ (15.18)	$ (16.97)	$ (26.97)
Canada natural gas – NYMEX	(0.31)	(0.63)	(1.06)	(0.78)	(0.48)
Bakken crude oil – WTI	(11.85)	(17.47)	(11.41)	(9.61)	(6.10)
Marcellus natural gas – NYMEX	(0.88)	(0.50)	(0.52)	(0.12)	(0.14)

(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$98.68/bbl during the quarter, an increase of approximately 5% versus the same quarter last year. After a weak start to the year, WTI prices rallied throughout most of the quarter to close at US$101.58/bbl by the end of March. The strengthening in oil prices was largely due to an increase in the movement of crude oil away from Cushing to the U.S. Gulf Coast as new pipeline capacity was brought into service. Crude oil inventory levels at Cushing fell to their lowest levels since 2011 which contributed to a narrowing of the differential between Brent and WTI to average US$9.19/bbl during the period. WTI prices were also helped by severe cold weather in the U.S. which caused temporary production interruptions and added support for distillate and heating fuel prices.

Heavy crude oil differentials in Canada improved significantly during the quarter, with WCS averaging US$23.13/bbl below WTI, compared to US$32.20/bbl below WTI in the fourth quarter of 2013. Light crude oil differentials also improved to average US$8.25/bbl below WTI during the quarter, compared to US$14.93/bbl in the fourth quarter of 2013. This improvement in Canadian differentials was due to extreme cold temperatures impacting field operations. We also saw improved takeaway capacity out of the region with additional rail egress coming into service and lower apportionment on key pipelines, which provided support for Canadian crude differentials during the quarter.

In the U.S., our average realized crude oil differential was US$11.85/bbl below WTI for the quarter. Similar to Canadian production, the weather related impact on production in the Bakken helped strengthen market differentials significantly. We continue to utilize a combination of pipeline and rail transportation to deliver our Bakken production to market.

Natural Gas

Natural gas prices at both AECO and NYMEX were significantly higher than the previous quarter and the first quarter of 2013, due to the severity of the winter weather causing the largest storage withdrawals in 20 years across North America. AECO monthly index prices increased by over 50% versus the previous quarter to average $4.76/Mcf, while NYMEX gas prices increased by 37% to average US$4.94/Mcf. U.S. storage stood at 826 Bcf at the end of the quarter, approximately 1,000 Bcf below the 5 year average for this time of the year. Natural gas prices remain strong with the market expecting that storage levels could be lower than normal at the end of the summer injection season.

We continue to maintain a balanced mix of AECO basis, month and daily index price exposures in our Canadian gas portfolio. During the quarter, approximately one-third of our Canadian gas was sold on a fixed basis, with approximately half receiving daily index prices and the balance receiving AECO monthly index prices.

Natural gas prices in some areas of the Marcellus also benefitted from the cold weather as peak demand in key centres in the U.S. Northeast caused regional prices on some pipelines to trade over US$100/Mcf on certain days. However, daily spot prices on the Transco Leidy and Tennessee Gas Pipeline 300 Leg averaged US$3.29/Mcf and US$3.04/Mcf, respectively (approximately US$1.65/Mcf and US$1.90/Mcf below NYMEX prices) due to oversupply. During the quarter approximately 45% of our Marcellus production was sold under long-term sales contracts that provided some protection from these discounts, resulting in an overall realized discount to NYMEX of $0.88/Mcf for our Marcellus production.

Overall, we sold our natural gas for an average price of $4.93/Mcf (net of transportation costs) during the quarter, which represented a 59% increase from the first quarter of 2013 and a 51% increase from the fourth quarter of 2013. The increase in our realized price was in line with the changes in both AECO and NYMEX prices over these periods.

Foreign Exchange

The majority of our oil and gas sales are based on U.S. dollar denominated indices and therefore a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. During the first quarter of 2014 there was a rapid depreciation of the Canadian dollar against the U.S. dollar as the U.S. economy continued to show signs of recovery while economic data out of Canada was below expectations. The Canadian dollar opened the year at a USD/CDN exchange rate of 1.0633 and weakened throughout the quarter to close at 1.1053. With this weakening, we began entering into foreign exchange costless collars on our oil and gas sales to protect a floor exchange rate while retaining some upside should the Canadian dollar weaken further.

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. As of April 24, 2014, we have swapped an average of 19,320 bbls/day of crude oil from April 1, 2014 to December 31, 2014 at an average price of US$94.24/bbl, which represents approximately 64% of our forecasted crude oil production after royalties. For the first half of 2015, we have swapped 5,500 bbls/day of crude oil at an average price of US$91.99/bbl, which represents approximately 18% of our forecasted crude oil production after royalties. Additionally, we have 500 bbls/day of crude oil swapped for the second half of 2015 at an average price of US$90.00/bbl.

We have entered into WCS differential swap positions for 2014 to manage our exposure to the risk of widening heavy crude oil differentials. These differential swaps have been fixed at an average price of WTI less a fixed spread of US$21.88/bbl on 2,000 bbls/day for April 2014, and at WTI less a fixed spread of US$21.00/bbl on 3,000 bbls/day from May through September of 2014 and 4,000 bbls/day from October through December of 2014. We have also entered into 2,000 bbl/day of Brent-WTI differential swap positions for the remainder of 2014, selling WTI at an average of 92.2% of Brent pricing.

As of April 24, 2014, we have downside protection on approximately 47% of our forecasted natural gas production after royalties for the remainder of 2014. This is comprised of 75,000 Mcf/day swapped at a NYMEX price of US$4.14/Mcf. In relation to these swaps, we have also purchased a call spread where we participate in price upside between US$4.17/Mcf and US$5.00/Mcf on 25,000 Mcf/day. Additionally, we have costless collars in place for the second half of 2014 for 30,000 Mcf/day, with an average floor of $4.30/Mcf and an average ceiling of $5.08/Mcf. At AECO we have 23,730 Mcf/day hedged at an average price of $4.23/Mcf, weighted towards the second half of 2014. For 2015, we have swapped 45,000 Mcf/day at a NYMEX price of US$4.21/Mcf. We also have NYMEX costless collars in place for 15,000 Mcf/day, with an average floor of $4.50/Mcf and an average ceiling of $5.54/Mcf for the first quarter of 2015. For 2015, we have downside protection of approximately 19% of our forecasted natural gas production after royalties.

We have also entered into foreign exchange costless collars to hedge a floor exchange rate on our U.S. dollar based oil and gas sales and to provide some upside potential in the event the Canadian dollar continues to weaken. As of April 24, 2014 we have $108 million 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. For 2015 we have $144 million hedged at average USD/CDN floor of 1.1083, ceiling of 1.1900 and conditional ceiling of 1.1254. Under these contracts, should the monthly foreign exchange rate settle above the ceiling rate then the conditional ceiling is used to determine the actual settlement amount.

The following is a summary of our financial contracts in place at April 24th, 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)			
	Apr 1, 2014 – Jun 30, 2014	Jul 1, 2014 – Sep 30, 2014	Oct 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Dec 31, 2015	Apr 1, 2014 – Jun 30, 2014	Jul 1, 2014 – Dec 31, 2014	Apr 1, 2014 – Jun 30, 2014	Jul 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Mar 31, 2015	Apr 1, 2015 – Dec 31, 2015
Purchased Puts									$ 4.30	$ 4.50	
%									12%	6%	
Sold Puts								$ 3.23	$ 3.23		
%								10%	10%		
Swaps	$ 93.98	$ 94.70	$ 94.07	$ 91.99	$ 90.00	$ 4.12	$ 4.25	$ 4.14	$ 4.14	$ 4.21	$ 4.21
%	77%	63%	53%	18%	2%	6%	11%	30%	30%	18%	18%
Sold Calls								$ 5.00	$ 5.04	$ 5.54	
%								10%	22%	6%	
Purchased Calls								$ 4.17	$ 4.17		
%								10%	10%		

(1) Based on weighted average price (before premiums), assumed average annual production of 96,000 – 100,000 BOE/day for 2014 and 2015, less royalties and production taxes of 23.5% in aggregate.

The following is a summary of our physical AECO-NYMEX basis contracts in place at April 24, 2014:

Instrument Type	MMcf/day	US$/Mcf
Apr 1, 2014 – Oct 31, 2014		
AECO-NYMEX Basis	60.0	(0.61)
Nov 1, 2014 – Oct 31, 2015		
AECO-NYMEX Basis	50.0	(0.66)
Nov 1, 2015 – Oct 31, 2016		
AECO-NYMEX Basis	60.0	(0.67)
Nov 1, 2016 – Oct 31, 2017		
AECO-NYMEX Basis	70.0	(0.64)
Nov 1, 2017 – Oct 31, 2018		
AECO-NYMEX Basis	70.0	(0.64)

ACCOUNTING FOR PRICE RISK MANAGEMENT

Risk Management Gains/(Losses) ($ millions)	Three months ended March 31, 2014	2013
Cash gains/(losses):		
Crude oil	$ (10.7)	$ 10.9
Natural gas	(4.6)	0.7
Total cash gains/(losses)	$ (15.3)	$ 11.6
Non-cash gains/(losses) on financial contracts:		
Change in fair value – crude oil	$ (9.4)	$ (29.6)
Change in fair value – natural gas	(7.9)	(9.0)
Total non-cash gains/(losses)	$ (17.3)	$ (38.6)
Total gains/(losses)	$ (32.6)	$ (27.0)

(Per BOE)	Three months ended March 31, 2014	2013
Total cash gains/(losses)	$ (1.72)	$ 1.47
Total non-cash gains/(losses)	(1.94)	(4.92)
Total gains/(losses)	$ (3.66)	$ (3.45)

During the first quarter of 2014, we realized cash losses of $10.7 million on our crude oil contracts and $4.6 million on our natural gas contracts. In comparison, during the first quarter of 2013, we realized cash gains of $10.9 million on our crude oil contracts and $0.7 million on our natural gas contracts. The cash losses in 2014 were a result of crude oil and natural gas prices rising above our fixed price swap positions. The 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 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 first quarter of 2014 the fair value of our crude oil and natural gas contracts represented net loss positions of $24.2 million and $7.5 million, respectively. The change in the fair value of our crude oil and natural gas contracts during the first quarter of 2014 represented losses of $9.4 million and $7.9 million respectively. See Note 14 for further information.

Revenues

($ millions)	Three months ended March 31, 2014	2013
Oil and natural gas sales	$ 495.0	$ 373.5
Royalties	(87.3)	(60.1)
Oil and natural gas sales, net of royalties	$ 407.7	$ 313.4

Crude oil and natural gas revenues were $495.0 million in the first quarter of 2014, representing an increase of 33% or $121.5 million compared to $373.5 million during the same period in 2013. Crude oil revenues increased due to higher realized prices, and natural gas revenues increased due to both higher production levels and realized prices.

Royalties and Production Taxes

	Three months ended March 31, 2014 ($ millions)	2014 (per BOE)	2013 ($ millions)	2013 (per BOE)
Royalties	$ 87.3	$ 9.82	$ 60.1	$ 7.66
Production taxes	19.9	2.23	14.6	1.86
Royalties and production taxes	$ 107.2	$ 12.05	$ 74.7	$ 9.52
Royalties and production taxes (% of oil and natural gas sales, net of transportation)	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 first quarter royalties and production taxes increased to $107.2 million from $74.7 million in the same quarter of 2013, primarily due to higher realized prices and increased production in the U.S. where rates are higher. Royalties and production taxes averaged 22% of oil and gas sales (net of transportation) in 2014 compared to 20% in 2013.

We continue to expect an average royalty and production tax rate of 23.5% in 2014.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended March 31, 2014	2013
Operating Expenses	$ 89.1	$ 81.3
Per BOE	$ 10.02	$ 10.37

Our operating expenses were in line with expectations totalling $89.1 million or $10.02/BOE during the first quarter compared to $81.3 million or $10.37/BOE in the first quarter of 2013. Operating costs improved on a per BOE basis due to increased production from our lower cost properties.

We are maintaining our annual guidance of $10.25/BOE for operating costs during 2014.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended March 31, 2014	2013
Transportation costs	$ 13.1	$ 7.2
Per BOE	$ 1.47	$ 0.92

Transportation costs for the first quarter were $13.1 million compared to $7.2 million in the same period in 2013. The increase in the first quarter of 2014 was related to higher U.S. production as well as costs associated with securing U.S. pipeline capacity.

Netbacks

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 March 31, 2014		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	42,283 BOE/day	339,228 Mcfe/day	98,821 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 85.93	$ 5.07	$ 54.19
Royalties and production taxes	(21.29)	(0.86)	(12.05)
Cash operating costs	(12.15)	(1.40)	(10.01)
Netback before hedging	$ 52.49	$ 2.81	$ 32.13
Cash gains/(losses)	(2.80)	(0.15)	(1.72)
Netback after hedging	$ 49.69	$ 2.66	$ 30.41
Netback before hedging ($ millions)	$ 199.7	$ 86.0	$ 285.7
Netback after hedging ($ millions)	$ 189.1	$ 81.3	$ 270.4

	Three months ended March 31, 2013		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	41,858 BOE/day	271,948 Mcfe/day	87,183 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 72.88	$ 3.75	$ 46.67
Royalties and production taxes	(16.69)	(0.48)	(9.52)
Cash operating costs	(11.67)	(1.55)	(10.42)
Netback before hedging	$ 44.52	$ 1.72	$ 26.73
Cash gains/(losses)	2.89	0.03	1.47
Netback after hedging	$ 47.41	$ 1.75	$ 28.20
Netback before hedging ($ millions)	$ 167.6	$ 42.1	$ 209.7
Netback after hedging ($ millions)	$ 178.5	$ 42.8	$ 221.3

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

Our crude oil properties accounted for 70% of our corporate netback before hedging for the first quarter of 2014 compared to 80% for the same period in 2013. The increased contribution from our natural gas properties is due to the improvement in natural gas prices. Crude oil netbacks also improved in 2014 with strengthening oil prices.

General and Administrative (G&A) Expenses

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 March 31,							
	2014				2013			
		($ millions)		(per BOE)		($ millions)		(per BOE)
Cash:								
G&A expense[1]	$	20.5	$	2.31	$	24.7	$	3.15
SBC		6.9		0.77		5.5		0.70
Non-Cash:								
SBC – equity swap loss/(gain)		(1.2)		(0.14)		(1.5)		(0.19)
SBC		2.9		0.33		2.5		0.32
Total G&A expenses	$	29.1	$	3.27	$	31.2	$	3.98

(1) Excluding share-based compensation.

Cash G&A expenses during the first quarter of 2014 were $20.5 million or $2.31/BOE compared to $24.7 million or $3.15/BOE in the first quarter of 2013. The $4.2 million decrease in cash G&A in the first quarter of 2014 was mainly due to one-time charges recorded in the prior year associated with the departure of personnel. Cash SBC during the first quarter of 2014 was $6.9 million compared to $5.5 million in the first quarter of 2013 primarily due to the increase in our share price. See Note 13 for further details.

We continue to expect cash G&A expenses to be approximately $2.45/BOE for 2014. With the increase in our share price and revised performance based multiplier estimates we are expecting cash SBC of $0.45/BOE in 2014, up from our previous guidance of $0.25/BOE. This guidance also assumes that new LTI grants will be non-cash and treasury-settled, which is pending shareholder approval.

Interest Expense

	Three months ended March 31,			
($ millions)		2014		2013
Interest on senior notes and bank facility	$	14.7	$	14.2
Non-cash interest expense		0.5		0.2
Total interest expense	$	15.2	$	14.4

We recorded total interest expense of $15.2 million during the first quarter of 2014 compared to $14.4 million for the same period in 2013 despite similar debt levels. Interest on our senior notes and bank credit facility increased slightly in 2014 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. See Note 10 for further details.

At March 31, 2014, after including our underlying derivatives, approximately 76% of our debt was based on fixed interest rates and 24% on floating interest rates.

Foreign Exchange

	Three months ended March 31,			
($ millions)		2014		2013
Realized loss/(gain)	$	0.1	$	2.7
Unrealized loss/(gain)		1.4		1.7
Total foreign exchange loss/(gain)	$	1.5	$	4.4

We recorded a net foreign exchange loss of $1.5 million during the first quarter of 2014 compared to $4.4 million for the same period in 2013. Realized losses result from day to day transactions denominated in foreign currencies. Unrealized foreign exchange losses on the translation of our U.S. dollar debt were partially offset by unrealized gains on our foreign exchange derivatives and U.S. dollar denominated working capital. See Note 11 for further details.

Capital Investment and Dispositions

	Three months ended March 31,	
($ millions)	2014	2013
Capital spending	$ 217.8	$ 172.9
Office capital	0.4	1.4
Sub-total	$ 218.2	$ 174.3
Property and land acquisitions	$ 10.0	$ 4.0
Property dispositions	(117.2)	(1.3)
Sub-total	$ (107.2)	$ 2.7
Total net capital investment	$ 111.0	$ 177.0

Capital spending for the first quarter of 2014 totaled $217.8 million compared to $172.9 million during the same period in 2013. Spending during the quarter focused on our core development areas, with $59.6 million spent at Fort Berthold and $60.2 million on our Canadian waterflood properties. Spending on our natural gas assets included $54.7 million at our Wilrich and Duvernay deep basin properties in Canada and $30.6 million on our Marcellus assets.

With the weakening of the Canadian dollar in 2014 we are seeing pressure on our reported capital spending for our U.S. operations where we plan to spend approximately 60% of our capital budget in 2014. We are increasing our capital spending guidance to $800 million from our original guidance of $760 million to account for the impact of a weaker Canadian dollar along with a slight increase in non-operated activity.

Property and land acquisitions for the first quarter of 2014 totaled $10.0 million which included the purchase of additional undeveloped land in North Dakota and Pennsylvania. In comparison, during the first quarter of 2013 we spent $4.0 million to purchase additional undeveloped land interests.

Property dispositions during the first quarter of 2014 totaled $117.2 million. The largest transactions were the balance of the proceeds on the sale of our Montney acreage of $68.6 million ($65.7 million was recognized in 2013 with respect to the first closing), and the sale of our overriding gas royalty interest in the Jonah property in Wyoming for proceeds of $44.8 million. During the first quarter of 2013 we completed minor non-core property dispositions for approximately $1.3 million.

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

	Three months ended March 31,	
($ millions, except per BOE amounts)	2014	2013
DDA&A expense	$ 132.2	$ 146.2
Per BOE	$ 14.86	$ 18.64

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2014 DDA&A was $132.2 million compared to $146.2 million for the same period in 2013. The decrease was primarily due to significant reserve additions for the year ended December 31, 2013 which lowered our depletion rate in 2014.

Marketable Securities

During the first quarter of 2014 we sold the remainder of our publicly listed investments for proceeds of $13.3 million recognizing a loss of $2.8 million.

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 $291.3 million at March 31, 2014 compared to $291.8 million at December 31, 2013. See Note 8 for further information.

Income Taxes

	Three months ended March 31,	
Income Tax ($ millions)	**2014**	**2013**
Current tax expense	$ 7.7	$ 1.3
Deferred tax expense	24.5	1.9
Total tax expense	$ 32.2	$ 3.2

We recorded a total tax expense of $32.2 million for the three months ended March 31, 2014 compared to a $3.2 million expense for the same period in 2013. The increase in the total tax expense is due to higher income in 2014.

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 divestiture activity we expect 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 QUARTERLY CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended March 31, 2014			Three months ended March 31, 2013		
(CDN$ millions, except per unit amounts)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	16,577	21,183	37,760	19,169	19,152	38,321
Natural gas liquids (bbls/day)	2,540	722	3,262	3,116	479	3,595
Natural gas (Mcf/day)	151,627	195,167	346,794	177,809	93,793	271,602
Total average daily production (BOE/day)	44,388	54,433	98,821	51,919	35,264	87,183
Pricing[2]						
Crude oil (per bbl)	$ 86.04	$ 95.74	$ 91.48	$ 68.00	$ 89.06	$ 78.52
Natural gas liquids (per bbl)	69.23	56.02	66.30	62.33	34.22	58.58
Natural gas (per Mcf)	5.11	4.79	4.93	2.89	3.50	3.10
Capital Expenditures						
Capital spending	$ 127.7	$ 90.1	$ 217.8	$ 83.0	$ 89.9	$ 172.9
Acquisitions	–	10.0	10.0	2.6	1.4	4.0
Dispositions	(67.7)	(49.5)	(117.2)	(1.3)	–	(1.3)
Netback Before Hedging						
Oil and natural gas sales, net of royalties	$ 186.0	$ 221.7	$ 407.7	$ 163.3	$ 150.1	$ 313.4
Operating expense	(62.1)	(26.9)	(89.0)	(66.7)	(15.2)	(81.9)
Production taxes	(2.0)	(17.9)	(19.9)	(1.4)	(13.2)	(14.6)
Transportation expense	(5.9)	(7.2)	(13.1)	(6.4)	(0.8)	(7.2)
Netback before hedging	$ 116.0	$ 169.7	$ 285.7	$ 88.8	$ 120.9	$ 209.7
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 32.6	$ –	$ 32.6	$ 27.0	$ –	$ 27.0
General and administrative expense[3]	15.5	5.0	20.5	21.4	3.3	24.7
Current income tax expense/(recovery)	(0.2)	7.9	7.7	–	1.3	1.3

(1) Company interest volumes.
(2) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.
(3) Excludes share-based compensation amounts.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2014				
First Quarter	$ 407.7	$ 40.0	$ 0.20	$ 0.19
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 2013	$ 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 2012	$ 1,153.3	$ (270.7)	$ (1.38)	$ (1.38)

Oil and gas sales increased in the first quarter of 2014 due to growth in natural gas production volumes as well as a strengthening in realized commodity prices compared to the fourth quarter of 2013. Oil and gas sales grew during 2013 with increasing production volumes. Net income generally improved during 2013 compared to 2012 due to increased production and realized prices as well as no asset impairments being recorded.

LIQUIDITY AND CAPITAL RESOURCES

The sustainability of our business continues to strengthen with improved cost efficiencies and profitability. Our adjusted payout ratio, which is calculated as dividends (net of our SDP proceeds) plus capital and office spending, divided by funds flow, improved to 118% for the first quarter of 2014 from 126% for the same period in 2013. We also recognized $107.2 million in net proceeds through our acquisition and divestment activities during the first quarter. At March 31, 2014 we had a conservative trailing 12 month debt to funds flow of 1.3x with approximately 81% of our bank credit facility undrawn.

Total debt net of cash at March 31, 2014, including the current portion, was $1,020.7 million compared to $1,022.3 million at December 31, 2013. Total debt was comprised of $186.5 million of bank indebtedness and $839.9 million of senior notes, less $5.7 million in cash. Our working capital deficiency, excluding cash and current deferred financial and tax assets and credits, decreased to $226.1 million at March 31, 2014 from $271.4 million at December 31, 2013. The decrease in our working capital deficit was mainly due to increased receivables resulting from higher production and improved commodity prices during the first quarter. 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	March 31, 2014	December 31, 2013
Long-term debt to funds flow (trailing 12-month)(1)	1.3x	1.4 x
Funds flow to interest expense (trailing 12-month)(2)	14.0x	13.3 x
Long-term debt to long-term debt plus equity(1)	34%	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 March 31, 2014 we were in compliance with all covenants under our bank credit facility and outstanding 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

($ millions, except per share amounts)	Three months ended March 31, 2014		2013	
Cash dividends	$	42.1	$	43.7
Stock dividend plan		12.8		10.1
Total dividends to shareholders	$	54.9	$	53.8
Per weighted average share (Basic)	$	0.27	$	0.27

We recorded a total of $54.9 million or $0.27 per share in dividends to our shareholders in the first quarter of 2014 compared to $53.8 million or $0.27 per share in the first quarter of 2013. 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 we eliminated the 5% discount with the intention of reducing shareholder dilution. Subsequently, our participation rate in the SDP is down significantly to 9% where we had previously been averaging 23%. Participation in the SDP for April was approximately $1.6 million compared to previous months at approximately $4.2 million.

Commitments

Subsequent to the quarter we secured a firm sales commitment for 5,000 bbl/day through March 2016 for our U.S. Bakken crude oil production.

Shareholders' Capital

	Three months ended March 31, 2014		2013	
Share capital ($ millions)	$	3,081.8	$	3,007.8
Common shares outstanding (thousands)		203,839		199,463
Weighted average shares outstanding – basic (thousands)		203,178		199,031
Weighted average shares outstanding – diluted (thousands)		205,878		199,031

During the first quarter of 2014 a total of 1,081,000 shares (2013 – 779,000) and $18.9 million of additional equity (2013 – $10.1) was issued pursuant to the SDP and the stock option plan. For further details see Note 13.

At March 31, 2014 we had 203,839,000 shares outstanding (2013 – 199,463,000) and at May 8, 2014 we had 204,190,000 shares outstanding.

2014 GUIDANCE

A summary of our revised 2014 guidance is below. This guidance does not include any potential acquisitions or divestments.

Summary of 2014 Expectations	Target
Average annual production	96,000 – 100,000 BOE/day
Capital spending	$800 million (from $760 million)
Production mix (volumes)	56% natural gas, 44% crude oil and liquids (from 52% natural gas and 48% crude oil and liquids)
Average royalty and production tax rate (% of gross sales, net of transportation)	23.5%
Operating costs	$10.25/BOE
Cash G&A expenses	$2.45/BOE
Cash share-based compensation expenses	$0.45/BOE (from $0.25/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 March 31, 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 January 1, 2014 and ended March 31, 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 and land holdings; our ability to reallocate funds within our 2014 capital program; 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 and equity issuances and expected use of proceeds therefrom; and the amount and timing of future dispositions and acquisitions.*

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.