Q1 2014

ENERPLUS FIRST QUARTER REPORT
THREE MONTHS ENDED MARCH 31, 2014

SELECTED FINANCIAL RESULTS	Three months ended March 31, 2014	2013
Financial (000's)		
Funds Flow	$ 220,512	$ 172,599
Cash and Stock Dividends	54,935	53,785
Net Income/(Loss)	40,037	(16,397)
Debt Outstanding – net of cash	1,020,720	1,125,762
Capital Spending	217,763	172,947
Property and Land Acquisitions	9,969	3,967
Property Dispositions	117,225	1,331
Debt to Trailing 12-Month Funds Flow	1.3x	1.7x
Financial per Weighted Average Shares Outstanding		
Funds Flow	$ 1.09	$ 0.87
Net Income (Basic)	0.20	(0.08)
Weighted Average Number of Shares Outstanding (000's)	203,178	199,031
Selected Financial Results per BOE(1)(2)		
Oil & Natural Gas Sales(3)	$ 54.19	$ 46.67
Royalties and Production Taxes	(12.05)	(9.52)
Commodity Derivative Instruments	(1.72)	1.47
Operating Costs	(10.01)	(10.42)
General and Administrative	(2.31)	(3.15)
Share-Based Compensation	(0.77)	(0.70)
Interest, Foreign Exchange and Other Expenses	(1.67)	(2.19)
Taxes	(0.87)	(0.16)
Funds Flow	$ 24.79	$ 22.00

SELECTED OPERATING RESULTS	Three months ended March 31, 2014	2013
Average Daily Production(2)		
Crude oil (bbls/day)	37,760	38,321
NGLs (bbls/day)	3,262	3,595
Natural gas (Mcf/day)	346,794	271,602
Total (BOE/day)	98,821	87,183
% Natural Gas	58%	52%
Average Selling Price(2)(3)		
Crude oil (per bbl)	$ 91.48	$ 78.52
NGLs (per bbl)	66.30	58.58
Natural gas (per Mcf)	4.93	3.10
Net Wells drilled	30	25

(1) Non-cash amounts have been excluded.
(2) Based on Company interest production volumes. See "Basis of Presentation" section in the following MD&A.
(3) Net of oil and gas transportation costs, but before royalties and the effects of commodity derivative instruments.

Average Benchmark Pricing	Three months ended March 31, 2014	2013
WTI crude oil (US$/bbl)	$ 98.68	$ 94.37
AECO – monthly index (CDN$/Mcf)	4.76	3.08
AECO – daily index (CDN$/Mcf)	5.71	3.20
NYMEX natural gas – last day (US$/Mcf)	4.94	3.34
USD/CDN exchange rate	1.10	1.01

Share Trading Summary For the three months ended March 31, 2014	CDN* – ERF (CDN$)	U.S.** – ERF (US$)
High	$ 22.37	$ 20.18
Low	$ 18.45	$ 17.15
Close	$ 22.10	$ 20.03

* TSX and other Canadian trading data combined.

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

2014 Dividends per Share	CDN$	US$(1)
January	$ 0.09	$ 0.08
February	$ 0.09	$ 0.08
March	$ 0.09	$ 0.08
First Quarter Total	$ 0.27	$ 0.24

(1) US$ dividends represent CDN$ dividends converted at the relevant foreign exchange rate on the payment date.

PRESIDENT'S MESSAGE

The first quarter of 2014 saw a continued focus on operational execution under a disciplined capital program. I am pleased to report that this focus delivered another quarter of production and funds flow growth for investors.

Production volumes grew by 5% in the first quarter compared to the fourth quarter of 2013, averaging 98,821 BOE per day. This increase was attributable to record production once again from the Marcellus, which averaged nearly 180 MMcf per day.

While our crude oil volumes were maintained quarter over quarter, adverse weather conditions caused production interruptions in both our Canadian and U.S. operations and slowed capital spending activities in our oil properties. We expect that our crude oil production will grow throughout 2014, achieving our guidance expectations as we move through the year. We are maintaining our annual average production guidance at 96,000 BOE per day to 100,000 BOE per day, however we expect to track towards the high end of the range due to the outperformance in the Marcellus. As a result, our natural gas weighting is expected to increase to 56% of total volumes.

Higher production levels and stronger commodity prices contributed to an increase in funds flow during the quarter. Funds flow grew to $220 million ($1.09 per share), up 22% from the previous quarter. Cold weather throughout many regions of North America caused natural gas prices to increase by over 50% and contributed to the growth in funds flow. This increase and the proceeds from our non-core divestment program also strengthened our balance sheet. Our debt to trailing twelve month funds flow ratio improved to 1.3x from 1.4x at year end.

Capital spending was slightly less than planned in the quarter due to weather interruptions delaying some of our completion activities, particularly in our U.S. oil assets. We invested $218 million and continue to be on track with our full year capital program. However, the decline in the Canadian dollar exchange rate vis-à-vis the U.S. dollar, while positive to revenues, will increase our reported capital spending for the year. With approximately 60% of our capital program invested in our U.S. assets, and modestly higher capital spending associated with our non-operated projects, our capital spending forecast for 2014 is expected to increase to $800 million, up 5% from our original estimate of $760 million.

Both our operating and G&A costs were in line with our estimates during the quarter. The decline of the Canadian dollar is expected to impact the reported operating costs of our U.S. assets, however with the increase in forecast production, on a BOE basis we expect corporate operating costs to remain at $10.25 per BOE. Cash general and administrative expenses are also expected to be maintained at $2.45 per BOE. Given the increase in our share price, we anticipate that cash share based compensation will increase by $0.20 per BOE to $0.45 per BOE.

As a result of the improvement in our sustainability and balance sheet over the past year, and to reduce dilution, we elected to remove the 5% discount applied to determine the number of shares issued under our Stock Dividend Program ("SDP") effective with the April 2014 dividend payment. The SDP remains in place, affording shareholders the opportunity to reinvest their dividends on a monthly basis.

Production and Capital Spending

	Three months ended March 31, 2014	
	Average Production Volumes	**Capital Spending** ($ millions)
Crude Oil & NGLs (bbls/day)		
Canada	19,117	$ 62
United States	21,905	59
Total Crude Oil & NGLs (bbls/day)	41,022	$ 121
Natural Gas (Mcf/day)		
Canada	151,627	$ 66
United States	195,167	31
Total Natural Gas (Mcf/day)	346,794	$ 97
Company Total (BOE/day)	98,821	$ 218

Net Drilling Activity – for the three months ended March 31, 2014

	Horizontal Wells Drilled	Wells Pending Completion/Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Crude Oil				
Canada	13.2	10.3	4.0	–
United States	5.3	5.3	1.8	–
Total Crude Oil	**18.5**	**15.6**	**5.8**	**–**
Natural Gas				
Canada	7.3	3.7	3.4	0.3
United States	4.1	4.1	2.3	–
Total Natural Gas	**11.4**	**7.8**	**5.7**	**–**
Company Total	**29.9**	**23.4**	**11.5**	**0.3**

* Wells drilled during the quarter that are pending potential completion/tie-in or abandonment as at March 31, 2014.

** Total wells brought on-stream during the quarter regardless of when they were drilled.

Asset Activity

We continued with an active capital program during the first quarter of 2014, spending $218 million across our four core areas. A total of 30 net horizontal wells were drilled, however, due to extreme weather, only 11.5 net wells were placed on stream, down significantly from the fourth quarter of 2013 when 19 net wells were brought on-stream. Our U.S. activities were focused in Fort Berthold, North Dakota and in the Marcellus in northeast Pennsylvania where we continue to see strong operational performance.

Production from Fort Berthold was maintained quarter over quarter despite the weather impact on production and the timing of our completion activities. Only 1.8 net wells were brought on-stream during the quarter. We are encouraged by the sustained performance of wells drilled in the fourth quarter with the new completion design. With 90 days of runtime, production volumes continue to be ahead of our expectations. Subsequent to the quarter, we brought on two wells from our second high density pad, one well producing from the Bakken and one well producing from the second bench of the Three Forks formation. In the first 26 days on production, the Bakken well has produced over 64,000 barrels of oil (an average of almost 2,500 bbls per day) and the second bench Three Forks well has produced over 60,000 barrels of oil (an average of 2,300 BOE per day). These are the best wells we've drilled to date.

Production from the Marcellus continues to surpass our expectations. Our drilling activities remain concentrated in the Bradford and Susquehanna areas where we are seeing strong well performance. Similar to North Dakota, well completions in the Marcellus continue to evolve with an increase in the number of stages and the amount of sand per stage in the fracs. During the quarter, 30 day initial production rates on wells drilled in the Bradford and Susquehanna areas averaged 15 MMcf per day, with two wells producing over 20 MMcf per day in their first 30 days.

We continued to invest in our waterflood portfolio in Canada where we advanced projects targeting the Ratcliffe, lower Mannville, Midale, Glauconitic, Cardium and Boundary Lake plays. Our Canadian gas activities were directed to the Wilrich and the Duvernay. We drilled two wells in the Ansell area targeting the Wilrich, and in the Willesden Green area, we've drilled and completed two horizontal wells targeting the Duvernay. We expect to be in a position to discuss results from this activity later in the year.

Crude Oil & Natural Gas Pricing

While the West Texas Intermediate benchmark price for crude oil was only marginally higher quarter over quarter, the more significant impact to Enerplus was a narrowing of crude oil differentials in both Canada and the U.S and the strengthening of the U.S. dollar. Our average realized sales price for our crude increased by approximately 18% to $91.48 during the quarter with crude oil sales generating approximately 70% of our corporate netback.

We also saw a significant improvement in the price of natural gas in both Canada and the United States during the quarter as winter weather caused the largest storage withdrawals in 20 years across North America. Our realized sales price for natural gas increased by over 50% quarter over quarter to average $4.93 per Mcf.

The growth in our Marcellus production volumes combined with higher natural gas prices has resulted in a significant increase in Marcellus net operating income to approximately $46 million during the quarter. With capital spending of approximately $31 million, the Marcellus generated $15 million of free cash flow in the first quarter. Based upon our outlook for production for the year, we expect the Marcellus to generate cash flow in excess of our capital spending in this area in 2014. Industry production from the region continues to outpace takeaway capacity putting pressure on the regional basis differentials. We believe this issue may persist for another year or two. We have long-term contracts and/or transportation to market points on approximately 75 – 85 MMcf per day which is helping to mitigate our exposure to these widening differentials, however, roughly 55% of our volumes are not contracted. Our Marcellus production realized an average discount of US$0.88 per Mcf relative to the NYMEX benchmark during the quarter. Higher production volumes and stronger NYMEX prices are resulting in an increase in funds flow in 2014.

We continued to enter into hedge contracts on our future crude oil and natural gas production in order to protect a minimum level of cash flow. We have significant hedge protection in place for the rest of 2014, with over 60% of our crude oil production net of royalties hedged and just over 45% of our natural gas production, net of royalties, hedged. However, beyond 2014, the forward commodity price markets are in backwardation on both crude oil and natural gas. We have roughly 10% of our forecast oil and 20% of our forecast natural gas hedged for 2015. We expect to layer in additional hedges over time.

Board & Executive Appointments

Mr. Doug Martin, Chairman of the Board of Enerplus, will be retiring at the end of 2014. Doug will step down from his position as Chairman effective June 1, 2014 but will remain a Board member until the end of the year to facilitate the transition for the new Chairman. Doug joined the Board of Directors of Enerplus in 2000, and since that time, has helped steer the Company through many commodity price cycles, changes within the landscape of the oil and gas industry, and our evolution from a trust to a corporation. I would like to thank Doug for his guidance and support over the past 14 years.

Mr. Elliott Pew, who is currently a Board member, will assume the position of Chairman of the Board for Enerplus. Elliott is a geologist and joined our Board in 2010, bringing a deep technical and commercial background within the oil and gas industry. He currently sits as the Chair of the Reserves Committee and a member of the Audit Committee.

I would also like to thank Mr. David O'Brien who is retiring and will not be standing for re-election as a Board member this year. David joined our Board in 2008 and his guidance and direction have helped to transform our business over the past five years. In planning for these changes, we added two new Board members during the quarter, Ms. Hilary Foulkes and Mr. Michael Culbert. Both individuals bring more than 30 years of experience in the oil and gas industry and their knowledge and expertise will enhance the strength of our Board.

I am also pleased to announce that Lisa Ower will be joining the executive team of Enerplus in the position of Vice-President of Human Resources effective May 20, 2014. Lisa brings a wealth of experience to the role having held similar positions within oil and gas production, mid-stream, manufacturing and business service industries. I welcome our new Board members and Lisa and look forward to their contributions in helping shape our future.

Summary

Enerplus is beginning 2014 from a position of strength. We continue to meet our commitments, demonstrating financial discipline in advancing our portfolio, improving our sustainability, and growing profitably within our framework of responsible development.

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation

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

	Three months ended March 31,	
Risk Management Gains/(Losses) ($ millions)	**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)

	Three months ended March 31,	
(Per BOE)	**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		2013	
	($ millions)	(per BOE)	($ millions)	(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.

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	March 31, 2014	December 31, 2013
Assets			
Current assets			
Cash		$ 5,737	$ 2,990
Accounts receivable	3	198,623	165,091
Deferred income tax asset		59,044	48,476
Deferred financial assets	14	13,178	9,198
Other current assets		6,472	7,641
		283,054	233,396
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	2,456,071	2,420,144
Other capital assets, net	4	20,262	21,210
Property, plant and equipment		2,476,333	2,441,354
Goodwill		616,206	609,975
Deferred income tax asset		338,514	364,411
Deferred financial assets	14	25,710	19,274
Marketable securities	5	–	13,389
Total Assets		$ 3,739,817	$ 3,681,799
Liabilities			
Current liabilities			
Accounts payable	6	$ 362,223	$ 377,157
Dividends payable		18,349	18,250
Current portion of long-term debt	7	50,623	48,713
Deferred financial credits	14	54,256	37,031
		485,451	481,151
Long-term debt	7	975,834	976,585
Asset retirement obligation	8	291,255	291,761
		1,267,089	1,268,346
Total Liabilities		1,752,540	1,749,497
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value Issued and outstanding: March 31, 2014 – 204 million shares December 31, 2013 – 203 million shares	13	3,081,770	3,061,839
Paid-in capital	13	40,338	38,398
Accumulated deficit		(1,132,136)	(1,117,238)
Accumulated other comprehensive income/(loss)		(2,695)	(50,697)
		1,987,277	1,932,302
Total Liabilities & Equity		$ 3,739,817	$ 3,681,799
Contingencies	15		

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Income/(Loss) and Comprehensive Income/(Loss)

Three months ended March 31 (CDN$ thousands) unaudited	**Note**		**2014**		**2013**
Revenues					
Oil and natural gas sales, net of royalties	9	$	407,740	$	313,381
Commodity derivative instruments gain/(loss)	14		(32,597)		(27,055)
			375,143		286,326
Expenses					
Operating			89,081		81,345
Production taxes			19,872		14,622
Transportation			13,109		7,197
General and administrative	13		29,123		31,209
Depletion, depreciation, amortization and accretion			132,180		146,223
Interest	10		15,179		14,436
Foreign exchange (gain)/loss	11		1,469		4,352
Other expense/(income)			2,912		128
			302,925		299,512
Income/(Loss) Before Taxes			72,218		(13,186)
Current income tax expense/(recovery)	12		7,678		1,307
Deferred income tax expense/(recovery)	12		24,503		1,904
Net Income/(Loss)		$	40,037	$	(16,397)
Other Comprehensive Income/(Loss)					
Changes due to marketable securities (net of tax)					
Unrealized gain/(loss)			(145)		515
Realized (gain)/loss reclassified to net income			2,503		(190)
Change in cumulative translation adjustment			45,644		20,853
Other Comprehensive Income/(Loss)			48,002		21,178
Total Comprehensive Income/(Loss)		$	88,039	$	4,781
Net Income/(Loss) per Share					
Basic		$	0.20	$	(0.08)
Diluted		$	0.19	$	(0.08)

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Changes in Shareholders' Equity

Three months ended March 31 (CDN$ thousands) unaudited		**2014**		**2013**
Share Capital				
Balance, beginning of year	$	3,061,839	$	2,997,682
Stock Option Plan – cash		6,138		21
Stock Option Plan – non-cash		1,012		2
Stock Dividend Plan		12,781		10,106
Balance, end of period	$	3,081,770	$	3,007,811
Paid-in Capital				
Balance, beginning of year	$	38,398	$	32,293
Stock Option Plan – exercised		(1,012)		(2)
Share-based compensation – non-cash		2,952		2,527
Balance, end of period	$	40,338	$	34,818
Accumulated Deficit				
Balance, beginning of year	$	(1,117,238)	$	(948,350)
Net income/(loss)		40,037		(16,397)
Dividends		(54,935)		(53,785)
Balance, end of period	$	(1,132,136)	$	(1,018,532)
Accumulated Other Comprehensive Income/(Loss)				
Balance, beginning of year	$	(50,697)	$	(130,385)
Changes due to marketable securities (net of tax)				
Unrealized gain/(loss)		(145)		515
Realized (gain)/loss reclassified to net income		2,503		(190)
Change in cumulative translation adjustment		45,644		20,853
Balance, end of period	$	(2,695)	$	(109,207)
Total Shareholders' Equity	$	1,987,277	$	1,914,890

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

Three months ended March 31 (CDN$ thousands) unaudited	**Note**	**2014**	**2013**
Operating Activities			
Net income/(loss)		$ 40,037	$ (16,397)
Non-cash items add/(deduct):			
Depletion, depreciation, amortization and accretion		132,180	146,223
Changes in fair value of derivative instruments	14	6,809	34,054
Deferred income tax expense/(recovery)	12	24,503	1,904
Foreign exchange (gain)/loss on debt and working capital	11	10,987	4,320
Share-based compensation	13	2,952	2,527
Amortization of debt issue costs	10	246	185
Asset disposition (gain)/loss	5	2,798	(217)
Asset retirement obligation expenditures	8	(4,292)	(3,378)
Changes in non-cash operating working capital	17	(75,810)	(7,987)
Cash flow from operating activities		140,410	161,234
Financing Activities			
Proceeds from the issuance of shares		6,138	21
Cash dividends	13	(42,154)	(43,679)
Change in bank debt		(30,570)	55,419
Changes in non-cash financing working capital		101	70
Cash flow from financing activities		(66,485)	11,831
Investing Activities			
Capital expenditures		(218,193)	(174,376)
Property and land acquisitions		(9,969)	(3,967)
Property dispositions		117,225	1,331
Sale of marketable securities	5	13,300	1,883
Changes in non-cash investing working capital		24,677	10,723
Cash flow from investing activities		(72,960)	(164,406)
Effect of exchange rate changes on cash		1,782	(1,306)
Change in cash		2,747	7,353
Cash, beginning of period		2,990	5,200
Cash, end of period		$ 5,737	$ 12,553

See accompanying notes to the Condensed Consolidated Financial Statements

Notes to Condensed Consolidated Financial Statements

(unaudited)

1) REPORTING ENTITY

These interim Condensed Consolidated Financial Statements ("interim Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation ("The Company" or "Enerplus") including its Canadian and U.S. subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada. The interim Consolidated Financial Statements were authorized for issue by the Board of Directors on May 8, 2014.

2) BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under accounting principles generally accepted in the United States of America ("U.S. GAAP") for the three months ended March 31, 2014, and the 2013 comparative periods. These interim Consolidated Financial Statements do not include all the necessary annual disclosures as prescribed under U.S. GAAP and should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2013. There are no differences in the use of estimates or judgments between these interim Consolidated Financial Statements and the audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2013.

3) ACCOUNTS RECEIVABLE

($ thousands)	March 31, 2014	December 31, 2013
Accrued receivables	$ 160,877	$ 122,482
Accounts receivable – trade	39,056	36,034
Current income tax receivable	1,488	9,371
Allowance for doubtful accounts	(2,798)	(2,796)
Total accounts receivable	$ 198,623	$ 165,091

4) PROPERTY, PLANT AND EQUIPMENT ("PP&E")

As at March 31, 2014 ($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties	$ 11,740,890	$ 9,284,819	$ 2,456,071
Other capital assets	90,735	70,473	20,262
Total PP&E	$ 11,831,625	$ 9,355,292	$ 2,476,333

As at December 31, 2013 ($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties	$ 11,481,207	$ 9,061,063	$ 2,420,144
Other capital assets	89,818	68,608	21,210
Total PP&E	$ 11,571,025	$ 9,129,671	$ 2,441,354

5) MARKETABLE SECURITIES

During the three months ended March 31, 2014 Enerplus sold the balance of its publicly listed investments for proceeds of $13.3 million recognizing a loss of $2.8 million. In connection with these sales, realized losses of $2.5 million net of tax ($2.8 million before tax) were reclassified from accumulated other comprehensive income to net income.

Realized gains and losses are included in other income on the Consolidated Statements of Income/(Loss).

For the three months ended March 31, 2014 the change in fair value of publicly listed investments represented unrealized losses of $0.1 million net of tax ($0.2 million before tax). For the three months ended March 31, 2013 the change in fair value of these investments represented unrealized gains of $0.5 million net of tax ($0.6 million before tax).

6) ACCOUNTS PAYABLE

($ thousands)	March 31, 2014	December 31, 2013
Accrued payables	$ 290,710	$ 262,117
Accounts payable – trade	71,513	115,040
Total accounts payable	$ 362,223	$ 377,157

7) DEBT

($ thousands)	March 31, 2014	December 31, 2013
Current:		
Senior notes	$ 50,623	$ 48,713
	50,623	48,713
Long-term:		
Bank credit facility	$ 186,505	$ 214,394
Senior notes	789,329	762,191
	975,834	976,585
Total debt	$ 1,026,457	$ 1,025,298

8) ASSET RETIREMENT OBLIGATION

Enerplus has estimated the present value of its asset retirement obligation to be $291.3 million at March 31, 2014 compared to $291.8 million at December 31, 2013, based on a total undiscounted liability of $716.8 million and $720.6 million, respectively. The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.93% (December 31, 2012 – 5.96%).

($ thousands)	Three months ended March 31, 2014	Year ended December 31, 2013
Balance, beginning of year	$ 291,761	$ 256,102
Change in estimates	502	44,217
Property acquisition and development activity	459	1,454
Dispositions	(927)	(8,362)
Settlements	(4,292)	(16,606)
Accretion expense	3,752	14,956
Balance, end of period	$ 291,255	$ 291,761

9) OIL AND NATURAL GAS SALES

	Three months ended March 31	
($ thousands)	2014	2013
Oil and natural gas sales	$ 495,024	$ 373,425
Royalties(1)	(87,284)	(60,044)
Oil and natural gas sales, net of royalties	$ 407,740	$ 313,381

(1) Royalties above do not include production taxes which are reported separately on the Consolidated Statements of Income/(Loss).

10) INTEREST EXPENSE

($ thousands)	Three months ended March 31 2014		2013
Realized:			
Interest on bank debt and senior notes	$ 14,666		$ 14,184
Unrealized:			
Cross currency interest rate swap (gain)/loss	267		333
Interest rate swap (gain)/loss	–		(266)
Amortization of debt issue costs	246		185
Interest expense	$ 15,179		$ 14,436

11) FOREIGN EXCHANGE

($ thousands)	Three months ended March 31 2014		2013
Realized:			
Foreign exchange (gain)/loss	$ 50		$ 2,732
Unrealized:			
Translation of U.S. dollar debt and working capital (gain)/loss	10,987		4,320
Cross currency interest rate swap (gain)/loss	(1,245)		(1,012)
Foreign exchange derivatives (gain)/loss	(8,323)		(1,688)
Foreign exchange (gain)/loss	$ 1,469		$ 4,352

12) INCOME TAXES

($ thousands)	Three months ended March 31 2014		2013
Current tax expense/(recovery)			
Canada	$ (184)		$ 4
United States	7,862		1,303
Current tax expense/(recovery)	7,678		1,307
Deferred tax expense/(recovery)			
Canada	$ 1,687		$ (12,469)
United States	22,816		14,373
Deferred tax expense/(recovery)	$ 24,503		$ 1,904
Income tax expense/(recovery)	$ 32,181		$ 3,211

The difference between the expected income taxes based on the statutory income tax rate and the effective income taxes for the current and prior period is impacted by the following: expected annual earnings, foreign rate differentials for foreign operations, statutory and other rate differentials, the reversal or recognition of previously unrecognized deferred tax assets, non-taxable portions of capital gains and losses, and non-deductible share-based compensation.

13) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized unlimited number of common shares **Issued:** (thousands)	Three months ended March 31 2014 Shares	Three months ended March 31 2014 Amount	Year ended December 31 2013 Shares	Year ended December 31 2013 Amount
Balance, beginning of year	202,758	$ 3,061,839	198,684	$ 2,997,682
Issued for cash:				
Stock Option Plan	431	6,138	1,042	14,838
Non-cash:				
Stock Option Plan	–	1,012	–	3,108
Stock Dividend Plan	650	12,781	3,032	46,211
Balance, end of period	203,839	$ 3,081,770	202,758	$ 3,061,839

b) Dividends

($ thousands)	Three months ended March 31 2014	2013
Cash dividends	$ 42,154	$ 43,679
Stock dividends	12,781	10,106
Dividends to shareholders	$ 54,935	$ 53,785

c) Share-based compensation

The following table summarizes Enerplus' share-based compensation expense, which is included in general and administrative expense on the Consolidated Statements of Income/(Loss):

($ thousands)	Three months ended March 31 2014	2013
Cash:		
Long-term incentive plans expense	$ 6,864	$ 5,518
Non-Cash:		
Share-based compensation	2,952	2,527
Equity swaps (gain)/loss	(1,222)	(1,515)
Share-based compensation expense	$ 8,594	$ 6,530

(i) Long-Term Incentive Plans

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Director Share Unit ("DSU") activity for the three months ended March 31, 2014 and other information at March 31, 2014:

For the period ended March 31, 2014 (thousands of units)	PSU	RSU	DSU	Total
Balance, beginning of year	650	821	99	1,570
Granted	525	775	47	1,347
Vested	–	(302)	–	(302)
Forfeited	(7)	(12)	–	(19)
Balance, end of period	1,168	1,282	146	2,596

At March 31, 2014 (in $ thousands, except for years)	PSU	RSU	DSU	Total
Recognized share-based compensation expense	$ 15,428	$ 8,731	$ 2,612	$ 26,771
Unrecognized share-based compensation expense	20,053	17,633	–	37,686
Intrinsic value(1)	$ 35,481	$ 26,364	$ 2,612	$ 64,457
Weighted-average remaining contractual term (years)(2)	2.0	1.6	–	

(1) Intrinsic value includes estimated performance multipliers with respect to the PSU plan.
(2) DSU awards are paid upon a Director leaving the Board.

Recognized share-based compensation expense represents the aggregate amount of expense recognized to date with respect to these plans. Unrecognized amounts will be recorded to share-based compensation expense over the remaining vesting terms.

For the three months ended March 31, 2014 the Company recorded total compensation costs of $7.7 million (March 31, 2013 – $5.5 million) and paid $11.5 million on settlements in relation to its long-term incentive plans (March 31, 2013 – $6.5 million).

(ii) Stock Option Plan

The Company did not grant any stock options during the three months ended March 31, 2014. Activity for the respective reporting periods is as follows:

	Three months ended March 31, 2014		Three months ended March 31, 2013	
	Number of Options (thousands)	Weighted Average Exercise Price	Number of Options (thousands)	Weighted Average Exercise Price(1)
Options outstanding, beginning of year	13,414	$ 18.65	10,768	$ 22.11
Granted(1)	–	–	5,802	13.96
Exercised	(431)	14.23	(1)	14.14
Forfeited	(251)	21.21	(265)	22.17
Options outstanding, end of period	12,732	$ 18.75	16,304	$ 19.21
Options exercisable, end of period	6,919	$ 21.55	4,803	$ 25.77

(1) The weighted average grant date fair value of options granted for the three months ended March 31, 2013 was $7.5 million.

At March 31, 2014, 6,919,000 options were exercisable at a weighted average exercise price of $21.55 with a weighted average remaining contractual term of 4.5 years, giving an aggregate intrinsic value of $20.3 million (March 31, 2013 – $0.1 million). The total intrinsic value of options exercised during the period ended March 31, 2014 was $2.9 million (March 31, 2013 – nil).

At March 31, 2014 the total share-based compensation expense related to non-vested options not yet recognized was $3.2 million. The expense is expected to be recognized in net income over a weighted-average period of 1.3 years.

d) Paid-in Capital

The following table summarizes the paid-in capital activity for the three months ended March 31, 2014 and the year ended December 31, 2013:

($ thousands)	Three months ended March 31, 2014	Year ended December 31, 2013
Balance, beginning of year	$ 38,398	$ 32,293
Stock Option Plan – exercised	(1,012)	(3,108)
Share-based compensation – non-cash	2,952	9,213
Balance, end of period	$ 40,338	$ 38,398

e) Basic and Diluted Earnings Per Share

Net income/(loss) per share has been determined as follows:

	Three months ended March 31	
(thousands, except per share amounts)	2014	2013
Net income/(loss)	$ 40,037	$ (16,397)
Weighted average shares outstanding – Basic	203,178	199,031
Dilutive impact of share-based compensation(1)	2,700	–
Weighted average shares outstanding – Diluted	205,878	199,031
Net income/(loss) per share		
Basic	0.20	(0.08)
Diluted	0.19	(0.08)

(1) For the three months ended March 31, 2013 options are anti-dilutive as their conversion to shares would not increase the loss per share.

14) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At March 31, 2014, the carrying value of cash, accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value due to the short-term maturity of the instruments. Based on Enerplus' assessment of the relative inputs used in the determination of fair value, these instruments are designated as Level 1.

At March 31, 2014 senior notes included in long-term debt had a carrying value of $840.0 million and a fair value of $890.2 million (December 31, 2013 – $810.9 million and $837.8 million, respectively).

Enerplus' derivative financial instruments are classified as Level 2. A Level 2 classification is appropriate where observable inputs other than quoted market prices are used in the fair value determination.

There were no transfers between fair value hierarchy levels during the period.

b) Derivative Financial Instruments

The deferred financial assets and credits on the Consolidated Balance Sheets result from recording derivative financial instruments at fair value.

The following table summarizes the change in fair value for the three months ended March 31, 2014 and 2013:

Gain/(Loss) ($ thousands)	March 31, 2014	March 31, 2013	Statement of Income/(Loss) Presentation
Interest Rate Swaps	$ –	$ 266	Interest
Cross Currency Interest Rate Swap:			
Interest	(267)	(333)	Interest
Foreign Exchange	1,245	1,012	Foreign exchange
Foreign Exchange Derivatives	8,323	1,688	Foreign exchange
Electricity Swaps	(46)	409	Operating
Equity Swaps	1,222	1,515	General and administrative
Commodity Derivative Instruments:			
Oil	(9,393)	(29,577)	Commodity derivative
Gas	(7,893)	(9,034)	instruments gain/(loss)
Total	$ (6,809)	$ (34,054)	

The following table summarizes the income statement effects of Enerplus' commodity derivative instruments:

	Three months ended March 31	
($ thousands)	2014	2013
Change in fair value gain/(loss)	$ (17,286)	$ (38,611)
Net realized cash gain/(loss)	(15,311)	11,556
Commodity derivative instruments gain/(loss)	$ (32,597)	$ (27,055)

The following table summarizes the fair values at the respective period ends:

	March 31, 2014			December 31, 2013		
	Assets		Liabilities	Assets		Liabilities
($ thousands)	Current	Long-term	Current	Current	Long-term	Current
Cross Currency Interest Rate Swap	$ –	$ –	$ 14,570	$ –	$ –	$ 15,548
Foreign Exchange Derivatives	1,805	22,217	–	564	15,135	–
Electricity Swaps	–	–	141	–	–	95
Equity Swaps	3,591	3,493	–	1,723	4,139	–
Commodity Derivative Instruments:						
Oil	2,356	–	26,581	4,138	–	18,970
Gas	5,426	–	12,964	2,773	–	2,418
Total	$ 13,178	$ 25,710	$ 54,256	$ 9,198	$ 19,274	$ 37,031

c) Risk Management

(i) Market Risk

Market risk is comprised of commodity price, foreign exchange, interest rate and equity price risk.

Commodity Price Risk:

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes net of royalties and production taxes.

The following tables summarize Enerplus' price risk management positions at April 24, 2014:

Crude Oil Instruments:

Instrument Type[1]	bbls/day	US$/bbl
Apr 1, 2014 – Apr 30, 2014		
WTI Swap	23,000	93.98
WCS Differential Swap	2,000	(21.88)
Brent Ratio Spread	2,000	92.20%
May 1, 2014 – Jun 30, 2014		
WTI Swap	23,000	93.98
WCS Differential Swap	3,000	(21.00)
Brent Ratio Spread	2,000	92.20%
July 1, 2014 – Sep 30, 2014		
WTI Swap	19,000	94.70
WCS Differential Swap	3,000	(21.00)
Brent Ratio Spread	2,000	92.20%
Oct 1, 2014 – Dec 31, 2014		
WTI Swap	16,000	94.07
WCS Differential Swap	4,000	(21.00)
Brent Ratio Spread	2,000	92.20%
Jan 1, 2015 – Jun 30, 2015		
WTI Swap	5,500	91.99
Jul 1, 2015 – Dec 31, 2015		
WTI Swap	500	90.00

(1) Transactions with a common term have been aggregated and presented at weighted average price/bbl.

Natural Gas Instruments:

Instrument Type	MMcf/day	CDN$/Mcf	US$/Mcf
Apr 1, 2014 – Jun 30, 2014			
AECO Swap	14.2	4.12	
Apr 1, 2014 – Jun 30, 2014			
NYMEX Swap	75.0		4.14
NYMEX Purchased Call	25.0		4.17
NYMEX Sold Put	25.0		3.23
NYMEX Sold Call	25.0		5.00
Jul 1, 2014 – Dec 31, 2014			
AECO Swap	28.4	4.25	
NYMEX Swap	75.0		4.14
NYMEX Purchased Put	30.0		4.30
NYMEX Purchased Call	25.0		4.17
NYMEX Sold Put	25.0		3.23
NYMEX Sold Call	55.0		5.04
Jan 1, 2015 – Mar 31, 2015			
NYMEX Swap	45.0		4.21
NYMEX Purchased Put	15.0		4.50
NYMEX Sold Call	15.0		5.54
Apr 1, 2015 – Dec 31, 2015			
NYMEX Swap	45.0		4.21

Electricity Instruments:

Instrument Type	MWh	CDN$/MWh
Apr 1, 2014 – Apr 30, 2014 AESO Power Swap(1)	18.0	52.18
May 1, 2014 – Dec 31, 2014 AESO Power Swap(1)	16.0	53.33
Jan 1, 2015 – Dec 31, 2015 AESO Power Swap(1)	13.0	51.08

(1) Alberta Electrical System Operator ("AESO") fixed pricing.

Physical Contracts:

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)

Foreign Exchange Instruments:

During the three months ended March 31, 2014, Enerplus entered into foreign exchange collars to hedge a portion of its foreign exchange exposure on U.S. dollar denominated oil and gas sales. The following contracts are outstanding at April 24, 2014:

Instrument Type(1)	Monthly Notional Amount (US$ millions)	Floor	Ceiling	Conditional Ceiling(2)
Apr 1, 2014 – Dec 31, 2014	12.0	1.1046	1.1558	1.1198
Jan 1, 2015 – Dec 31, 2015	12.0	1.1083	1.1900	1.1254

(1) Transactions with a common term have been aggregated and presented at average USD/CDN foreign exchange rates.
(2) If the US$/CDN$ average monthly rate settles above the ceiling rate the settlement amount is determined based on the conditional ceiling.

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations and U.S. dollar denominated senior notes and working capital. Additionally, Enerplus' crude oil sales and a portion of its natural gas sales are based on U.S. dollar indices. Enerplus manages currency risk relating to its senior notes through the derivative instruments detailed below.

Cross Currency Interest Rate Swap ("CCIRS"):

Concurrent with the issuance of the US$175 million senior notes on June 19, 2002, Enerplus entered into a CCIRS with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal payments at a notional amount of CDN$268.3 million. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%. At March 31, 2014 the remaining U.S. dollar denominated principal is fixed at a notional amount of CDN$53.7 million. The CCIRS matures in June 2014 in conjunction with the final principal repayment on the notes.

Foreign Exchange Derivatives:

During 2007 Enerplus entered into foreign exchange swaps on US$54.0 million of notional debt at an average US$/CDN$ exchange rate of 1.02. At March 31, 2014, following the third settlement, Enerplus had US$21.6 million of remaining notional debt swapped. These foreign exchange swaps mature between October 2014 and October 2015 in conjunction with the remaining principal repayments on the US$54.0 million senior notes.

During 2011 Enerplus entered into foreign exchange swaps on US$175.0 million of notional debt at approximately par. These foreign exchange swaps mature between June 2017 and June 2021 in conjunction with the principal repayments on the US$225.0 million senior notes.

Interest Rate Risk:

At March 31, 2014, approximately 76% of Enerplus' debt was based on fixed interest rates and 24% was based on floating interest rates. At March 31, 2014 Enerplus did not have any interest rate derivatives outstanding other than the CCIRS mentioned above.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its cash settled long-term incentive plans detailed in Note 13.

Enerplus has entered into various equity swaps maturing between 2013 and 2016 and has effectively fixed the future settlement cost on 995,000 shares at a weighted average price of $14.78 per share.

(ii) Credit Risk

Credit risk represents the financial loss Enerplus would experience due to the potential non-performance of counterparties to its financial instruments. Enerplus is exposed to credit risk mainly through its joint venture, marketing and financial counterparty receivables.

Enerplus mitigates credit risk through credit management techniques, including conducting financial assessments to establish and monitor counterparties' credit worthiness, setting exposure limits, monitoring exposures against these limits and obtaining financial assurances such as letters of credit, parental guarantees, or third party credit insurance where warranted. Enerplus monitors and manages its concentration of counterparty credit risk on an ongoing basis.

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At March 31, 2014 approximately 75% of Enerplus' marketing receivables were with companies considered investment grade.

At March 31, 2014 approximately $2.6 million or 1% of Enerplus' total accounts receivable were aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at March 31, 2014 was $2.8 million (December 31, 2013 – $2.8 million).

(iii) Liquidity Risk & Capital Management

Liquidity risk represents the risk that Enerplus will be unable to meet its financial obligations as they become due. Enerplus mitigates liquidity risk through actively managing its capital, which it defines as debt (net of cash) and shareholders' capital. Enerplus' objective is to provide adequate short and longer term liquidity while maintaining a flexible capital structure to sustain the future development of its business. Enerplus strives to balance the portion of debt and equity in its capital structure given its current oil and natural gas assets and planned investment opportunities.

Management monitors a number of key variables with respect to its capital structure, including debt levels, capital spending plans, dividends, access to capital markets, as well as acquisition and divestment activity.

15) CONTINGENCIES

Enerplus is subject to various legal claims and actions arising in the normal course of business. Although the outcome of such claims and actions cannot be predicted with certainty, the Company does not expect these matters to have a material impact on the interim Consolidated Financial Statements. In instances where the Company determines that a loss is probable and the amount can be reasonably estimated, an accrual is recorded.

16) GEOGRAPHICAL INFORMATION

As at and for the three months ended March 31, 2014 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 185,966	$ 221,774	$ 407,740
Plant, property and equipment	1,086,784	1,389,549	2,476,333
Goodwill	451,122	165,084	616,206

As at and for the three months ended March 31, 2013 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 163,243	$ 150,138	$ 313,381
Plant, property and equipment	1,364,797	1,061,363	2,426,160
Goodwill	451,121	151,687	602,808

17) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	Three months ended, March 31, 2014	Three months ended March 31, 2013
Accounts receivable	$ (37,424)	$ (3,832)
Other current assets	923	(987)
Accounts payable	(39,309)	(3,168)
	$ (75,810)	$ (7,987)

b) Other

($ thousands)	Three months ended, March 31, 2014	Three months ended, March 31, 2013
Income taxes paid/(received)	$ (134)	$ (5,246)
Interest paid	$ 2,383	$ 2,874

BOARD OF DIRECTORS

Douglas R. Martin[(1)(2)]
Corporate Director
Calgary, Alberta

David H. Barr[(9)(11)]
Corporate Director
The Woodlands, Texas

Michael R. Culbert
President & CEO
Progress Energy Canada Ltd.
Calgary, Alberta

Edwin V. Dodge[(9)(12)]
Corporate Director
Vancouver, British Columbia

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

Hilary A. Foulkes
Corporate Director
Calgary, Alberta

James B. Fraser[(7)(11)]
Corporate Director
Polson, Montana

Robert B. Hodgins[(3)(6)]
Corporate Director
Calgary, Alberta

Susan M. MacKenzie[(7)(10)]
Corporate Director
Calgary, Alberta

Donald J. Nelson[(3)(9)]
President
Fairway Resources, Inc.
Calgary, Alberta

David O'Brien[(3)]
Corporate Director
Calgary, Alberta

Elliott Pew[(5)(8)]
Corporate Director
Boerne, Texas

Glen D. Roane[(4)(5)]
Corporate Director
Canmore, Alberta

Sheldon B. Steeves[(5)(7)]
Corporate Director
Calgary, Alberta

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas
President & Chief Executive Officer

Ray J. Daniels
Senior Vice President, Operations

Eric G. Le Dain
Senior Vice President, Corporate Development, Commercial

Robert J. Waters
Senior Vice President & Chief Financial Officer

Jo-Anne M. Caza
Vice President, Corporate & Investor Relations

Robert A. Kehrig
Vice President, Business Development and New Plays

Jodine J. Jenson Labrie
Vice President, Finance

H. Gordon Love
Vice President, Technical & Operations Services

David A. McCoy
Vice President, Corporate Services, General Counsel & Corporate Secretary

Edward L. McLaughlin
President, Enerplus Resources (USA) Corporation

Christopher M. Stephens
Vice President, Canadian Assets

P. Scott Walsh
Vice President, Information Systems

Kenneth W. Young
Vice President, Land

Michael R. Politeski
Treasurer & Corporate Controller

(1) Chairman of the Board
(2) *Ex-Officio* member of all Committees of the Board
(3) Member of the Corporate Governance & Nominating Committee
(4) Chairman of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chairman of the Audit & Risk Management Committee
(7) Member of the Reserves Committee
(8) Chairman of the Reserves Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chairman of the Compensation & Human Resources Committee
(11) Member of the Safety & Social Responsibility Committee
(12) Chairman of the Safety & Social Responsibility Committee

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION

Enerplus Resources (USA) Corporation

LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Calgary, Alberta

AUDITORS

Deloitte LLP
Calgary, Alberta

TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta
Toll free: 1.866.921.0978

U.S. CO-TRANSFER AGENT

Computershare Trust Company, N.A.
Golden, Colorado

INDEPENDENT RESERVE ENGINEERS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates,Inc.
Dallas, Texas

STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

Toronto Stock Exchange: ERF
New York Stock Exchange: ERF

U.S.OFFICE

950 17th Street, Suite2200
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ABBREVIATIONS

AECO	a reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices
bbl(s)/day	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S.gallons
Bcf	billion cubic feet
Bcfe	billion cubic feet equivalent
BOE	barrels of oil equivalent
Brent	crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $US dollars.
LTI	long-term incentive
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf	million cubic feet
MSW	mixed sweet blend
MWh	megawatt hour(s) of electricity
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange, the benchmark for North American natural gas pricing
OCI	other comprehensive income
SBC	share based compensation
SDP	stock dividend program
U.S. GAAP	accounting principles generally accepted in the United States of America
WCS	Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

Why invest in Enerplus?

Enerplus is a North American energy producer with a portfolio of oil and gas assets in resource plays that offer organic growth potential with superior economics. We are focused on creating value for our investors through the execution of a disciplined capital investment strategy that allows the successful development of our properties, supported by a strong financial plan. We are a responsible developer of resources that strives to provide investors with a competitive return comprised of both growth and income.

enerPLUS

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