Q3 2014

enerPLUS

ENERPLUS THIRD QUARTER REPORT
NINE MONTHS ENDED SEPTEMBER 30, 2014

SELECTED FINANCIAL RESULTS	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Financial (000's)				
Funds Flow	$ 212,779	$ 196,187	$ 646,502	$ 573,492
Cash and Stock Dividends	55,438	54,405	165,587	162,199
Net Income	67,430	(3,720)	147,424	18,350
Debt Outstanding – net of cash	1,091,110	964,577	1,091,110	964,577
Capital Spending	207,838	145,811	630,027	458,402
Property and Land Acquisitions	3,986	15,792	17,186	71,451
Property Dispositions	68,931	124,462	185,631	197,086
Debt to Trailing 12-Month Funds Flow	1.3x	1.2x	1.3x	1.2x
Financial per Weighted Average Shares Outstanding				
Funds Flow	$ 1.04	$ 0.98	$ 3.17	$ 2.87
Net Income (Basic)	0.33	(0.02)	0.72	0.09
Weighted Average Number of Shares Outstanding (000's)	205,164	201,117	204,174	200,002
Selected Financial Results per BOE(1)(2)				
Oil & Natural Gas Sales(3)	$ 46.13	$ 53.61	$ 50.66	$ 49.67
Royalties and Production Taxes	(10.36)	(11.91)	(11.31)	(10.46)
Commodity Derivative Instruments	(0.26)	(1.30)	(1.52)	0.42
Operating Costs	(10.67)	(10.58)	(10.28)	(10.52)
General and Administrative	(1.97)	(2.48)	(2.08)	(2.63)
Share-Based Compensation	0.54	(0.60)	(0.44)	(0.58)
Interest, Foreign Exchange and Other Expenses	(1.18)	(1.78)	(1.48)	(1.78)
Taxes	–	(0.65)	(0.40)	(0.33)
Funds Flow	$ 22.23	$ 24.31	$ 23.15	$ 23.79

SELECTED OPERATING RESULTS	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Average Daily Production(2)				
Crude oil (bbls/day)	40,332	38,883	39,328	38,426
NGLs (bbls/day)	3,869	2,985	3,591	3,357
Natural gas (Mcf/day)	359,007	275,164	356,288	279,212
Total (BOE/day)	104,035	87,729	102,300	88,318
% Natural Gas	58%	52%	58%	53%
Average Selling Price(2)(3)				
Crude oil (per bbl)	$ 86.49	$ 96.30	$ 90.91	$ 86.05
NGLs (per bbl)	44.85	49.88	53.01	51.48
Natural gas (per Mcf)	3.22	2.96	4.04	3.26
Net Wells drilled	19	15	63	50

(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 September 30, 2014	2013	Nine months ended September 30, 2014	2013
WTI crude oil (US$/bbl)	$ 97.17	$ 105.82	$ 99.61	$ 98.14
AECO – monthly index (CDN$/Mcf)	4.22	2.82	4.55	3.16
AECO – daily index (CDN$/Mcf)	4.02	2.43	4.81	3.05
NYMEX – last day (US$/Mcf)	4.06	3.58	4.55	3.67
USD/CDN exchange rate	1.09	1.04	1.09	1.02

Share Trading Summary For the three months ended September 30, 2014	CDN* – ERF (CDN$)	U.S.** – ERF (US$)
High	$ 27.05	$ 25.37
Low	$ 20.21	$ 18.45
Close	$ 21.26	$ 18.97

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

2014 Dividends per Share Payment Month	CDN$	US$(1)
First Quarter Total	$ 0.27	$ 0.24
Second Quarter Total	$ 0.27	$ 0.24
July	$ 0.09	$ 0.08
August	$ 0.09	$ 0.08
September	$ 0.09	$ 0.08
Third Quarter Total	$ 0.27	$ 0.24
Total Year-to-Date	$ 0.81	$ 0.72

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

PRESIDENT'S MESSAGE

Through the third quarter of 2014, Enerplus continued to deliver consistent, strong operational and financial performance. Despite a decline in both crude oil and natural gas prices, both funds flow and production were maintained quarter over quarter. We also continued to execute on our non-core divestment strategy, successfully completing two transactions, further strengthening our financial position.

Daily production averaged approximately 104,000 BOE, essentially unchanged from the second quarter. Crude oil and natural gas liquids production increased again in the third quarter to average 44,200 barrels per day, up 700 barrels over the second quarter. We continue to achieve strong performance from our Bakken/Three Forks properties in North Dakota with production increasing by approximately 1,600 BOE per day. Natural gas production was maintained quarter over quarter despite an average of 3,000 – 4,000 BOE per day of Marcellus production being temporarily curtailed due to pipeline maintenance and low natural gas prices in the region.

We continued to execute our capital spending program with discipline in conjunction with a solid financial plan. During the third quarter, we invested $208 million on development drilling activities. Our U.S. assets attracted the majority of our capital spending during the quarter, with roughly two thirds of the capital, drilling and on-stream activity attributable to the Bakken and the Marcellus. In total, we drilled 19.3 net wells and brought 17.3 net wells on-stream across our portfolio.

Despite the drop in commodity prices, funds flow was maintained quarter over quarter at $213 million or $1.04 per share. As previously announced, with the strength of our balance sheet and the improved sustainability of our business, we elected to suspend our Stock Dividend Program ("SDP"). Our current dividend is at an affordable level representing 26% of funds flow. Suspension of the SDP will reduce dilution and help to improve our per share metrics in the future.

We continued to execute on our divestment strategy during the quarter. On September 30, 2014 we closed the sale of approximately 1,900 BOE/day of non-operated production in Canada, 75% weighted to natural gas. We also sold an additional 1,200 BOE/day of Canadian non-operated production (90% weighted to natural gas) which closed in early November. The total proceeds from these transactions are expected to be approximately $91 million reflecting attractive metrics of approximately $30,000 per flowing barrel of production that is predominately natural gas. We intend to continue to look for opportunities to rationalize non-core production, providing us with the opportunity to accelerate spending on our core assets while maintaining our financial strength.

Our non-core divestment activities have generated proceeds of over $200 million year-to-date in 2014. We have continued to meet or surpass our production guidance despite the sale of approximately 3,500 BOE per day of production. As a result of the success of our divestment program, we have redeployed a portion of these proceeds to advance opportunities within our core properties. We have accelerated some of our 2015 activity into the fourth quarter of 2014, particularly in the Wilrich and at Fort Berthold. We anticipate this will have only a modest impact in 2014 but will bring additional production on-stream earlier in 2015. We plan to spend an additional $30 million this year, and are adjusting our full-year capital spending to $830 million.

Production performance year-to-date has been strong, despite the sale of non-core production and curtailed production volumes from the Marcellus. We are increasing the low end of our annual production range and now expect full year production to average between 102,000 – 104,000 BOE per day. The low end of this range largely reflects the risk of additional curtailment in the Marcellus in the fourth quarter. To date in the fourth quarter, we have continued to see our crude oil volumes grow as a result of our development activity at Fort Berthold and expect to achieve our full-year liquids target of 44,000 barrels per day.

Production and Capital Spending

	Three months ended September 30, 2014		Nine months ended September 30, 2014	
	Average Production Volumes	Capital Spending ($ millions)	Average Production Volumes	Capital Spending ($ millions)
Crude Oil & NGLs (BOE/day)				
Canada	19,415	$ 37	19,398	$ 128
United States	24,786	96	23,521	255
Total Crude Oil & NGLs (BOE/day)	44,201	$ 133	42,919	$ 383
Natural Gas (Mcf/day)				
Canada	154,855	$ 18	154,306	$ 115
United States	204,152	57	201,982	132
Total Natural Gas (Mcf/day)	359,006	$ 75	356,288	$ 247
Company Total (BOE/day)	104,035	$ 208	102,300	$ 630

Net Drilling Activity – for the three months ended September 30, 2014

	Horizontal Wells	Wells Pending Completion/ Tie-in *	Wells On-stream**	Dry & Abandoned Wells
Crude Oil				
Canada	3.4	2.2	5.5	–
United States	6.6	6.6	5.6	–
Total Crude Oil	**10.0**	**8.8**	**11.1**	**–**
Natural Gas				
Canada	2.1	1.4	0.8	–
United States	7.2	6.9	5.4	–
Total Natural Gas	**9.3**	**8.3**	**6.2**	**–**
Company Total	**19.3**	**17.1**	**17.3**	**–**

* Wells drilled during the quarter that are pending potential completion/tie-in or abandonment as at September 30, 2014.

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

Asset Activity

Drilling activity continued at a brisk pace in Fort Berthold during the third quarter with 6.6 net wells drilled and 5.6 net wells brought on-stream. Production grew again to average 22,400 BOE per day, up almost 1,600 BOE per day from the second quarter. Year-to-date, we have continued to drill into both the Bakken and Three Forks zones with 10 operated wells and 2.4 net non-operated wells brought on-stream. Production performance has continued to improve as a result of our completion optimization activity. The 30 day initial production rates on our two mile horizontal wells brought on-stream in 2014 have averaged 1,725 barrels per day, 20% above our high expected ultimate recovery type curve. We are also seeing an improvement of over 10% in the 60 day production rates which have averaged approximately 1,400 barrels per day.

In the Marcellus, drilling activity continued with 7.2 net wells drilled and 5.4 net wells brought on-stream. Continued production growth and the shortage of takeaway capacity continued to put pressure on basis differentials in the region. Our Marcellus production received a discount of US$1.72 per Mcf to the NYMEX benchmark price during the quarter. As a result of lower prices in the region, combined with pipeline maintenance, 3,000 – 4,000 BOE per day of production was intentionally curtailed during the quarter. Despite this curtailment, production from the Marcellus was essentially unchanged from the second quarter, averaging 187 MMcf per day. Plans are currently underway to slow our pace of activity, moving from a four-rig program to a two-rig program. As a result, we expect capital spending on our Marcellus assets in the fourth quarter to be meaningfully lower than in the third quarter.

As discussed earlier in the year, Enerplus has drilled and completed two horizontal Duvernay wells in the Willesden Green area of central Alberta. Our initial horizontal well at 1-7-45-5W5M was completed in the first quarter of 2014 with a 13 stage hybrid slickwater frac. The well was subsequently shut-in for installation of surface equipment and pipeline tie-in. In late June, we brought this well on production achieving a

30 day initial production rate of 535 BOE per day including 2.24 MMcf per day of sales gas with 162 barrels per day of total liquids, 53% condensate.

Our second horizontal well at 15-8-46-9W5M was completed in the second quarter of this year with a 14 stage hybrid slickwater frac. This well was also shut-in while surface equipment and pipelines were installed to a third party gas plant and oil battery in the area. We brought this well on-stream in early October and during the first 30 days of production, it has averaged an estimated 700 BOE per day including 1.75 MMcf per day of sales gas, with 410 barrels per day of liquids, roughly 85% condensate.

Both wells have met our expectations on liquids content based upon our geotechnical analysis. The cost of these wells was higher than we expected, particularly on the completions, which is similar to what others have experienced in this deep, over-pressured play. We see a number of opportunities to increase drilling and completion efficiencies going forward, particularly with multi-well pads. Further evaluation of these wells over the coming months is required in order to determine our next steps.

Outlook

Despite the current decline in crude oil prices, Enerplus is very well positioned. Based upon our revised production guidance, we expect to deliver above-average production growth of 13% per share in 2014. Our balance sheet is very strong. Our dividend payout is conservative and our debt-to-trailing 12 month funds flow ratio was 1.3 times at the end of the quarter and we have virtually all of our $1 billion revolving line of credit available. We also have a significant portion of our crude oil production hedged for the remainder of 2014 and into 2015 at prices well above the current market. We anticipate that these positions will provide strong funds flow protection through the fourth quarter and into 2015, lending support for our plans for the remainder of this year and next.

Our preliminary plans for 2015 target continued production growth of 5%-10% per share with a modestly lower capital spending program than in 2014. We have a significant portfolio of economic development opportunities in both crude oil and natural gas that are expected to provide us with organic growth potential for many years. We expect to maintain our strong financial position and will continue to apply discipline to our capital spending program, ensuring that our plans are affordable and that our business is sustainable.

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 November 6, 2014 and is to be read in conjunction with:

- the unaudited interim consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three and nine months ended September 30, 2014 and 2013 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011 (the "Financial Statements"); and
- our MD&A for the year ended December 31, 2013 (the "Annual MD&A").

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

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

BASIS OF PRESENTATION

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

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

NON-GAAP MEASURES

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

"Netback" is used by Enerplus and is useful to investors and securities analysts in evaluating 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 by Enerplus and is useful to investors and securities analysts in analyzing 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 September 30,		Nine months ended September 30,	
Reconciliation of Cash Flow from Operating Activities to Funds Flow	**2014**	**2013**	**2014**	**2013**
Cash flow from operating activities	$ 199,045	$ 218,170	$ 567,961	$ 574,828
Asset retirement obligation expenditures	3,299	3,701	11,831	10,036
Changes in non-cash operating working capital	10,435	(25,684)	66,710	(11,372)
Funds flow	$ 212,779	$ 196,187	$ 646,502	$ 573,492

"Debt to Funds Flow Ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing 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 by Enerplus and is useful to investors and securities analysts in analyzing 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 for the third quarter averaged 104,035 BOE/day, consistent with the prior quarter and an increase of 19% compared to the same period in 2013. Crude oil and natural gas liquids production grew by 2% compared to the prior quarter, while natural gas volumes were essentially flat. Low natural gas prices and pipeline maintenance resulted in production curtailments of approximately 3,000-4,000 BOE/day in the Marcellus during the quarter. Despite these interruptions, average production volumes for the year to date are ahead of expectations and we have increased our guidance again for 2014 to 102,000-104,000 BOE/day from 100,000-104,000 BOE/day.

Our capital spending program continued to focus on our core development areas, with $207.8 million spent in the third quarter. As discussed in our second quarter release, the successful divestment of approximately $91.0 million of non-core assets in the second half of 2014 has provided us with additional flexibility and we have redeployed a portion of the divestment proceeds to accelerate our 2015 capital program in our core areas. Accordingly, we have increased our capital spending guidance for 2014 to $830 million from $800 million.

Funds flow for the third quarter totaled $212.8 million compared to $213.2 million in the second quarter and $196.2 million in the same period in 2013. In the third quarter our funds flow was impacted by lower commodity prices however this was partially offset by cash share-based compensation recoveries given the industry wide sell off in equities. Lower commodity prices at quarter end resulted in a $93.8 million non-cash gain on our commodity derivatives which contributed to a nearly 70% increase in our net income compared to the second quarter.

Cash general and administrative expenses for the quarter of $1.97/BOE were consistent with the second quarter. Operating costs increased to $10.67/BOE, compared to $10.09/BOE in the prior quarter, due to production curtailments on our lower operating cost Marcellus properties along with seasonal well servicing and higher repairs and maintenance costs. Based on continued production curtailments in the Marcellus throughout the fourth quarter, we are reverting to our original 2014 operating costs guidance of $10.25/BOE from $10.10/BOE.

Although oil prices declined significantly during the quarter, we continue to maintain a strong balance sheet and financial flexibility. During the quarter, we closed a US$200 million private placement of 3.79%, 10 year average life senior notes and used the proceeds to repay outstanding bank debt. At September 30, 2014 only 5% of our $1 billion credit facility was drawn and our trailing 12 month debt to funds flow ratio was 1.3x. We also have a strong hedge position in place with approximately 64% of our anticipated remaining 2014 crude oil production hedged at a price of $95.29, and approximately 38% of our anticipated 2015 crude oil production hedged at $93.68.

RESULTS OF OPERATIONS

Production

Production levels were maintained in the third quarter with production of 104,035 BOE/day despite production curtailments that averaged 3,000-4,000 BOE/day over the quarter due to decreased natural gas prices and pipeline maintenance in the Marcellus. Our Fort Berthold crude oil production grew by 6% from the prior quarter with our ongoing development program more than fully offsetting the decline in other crude oil assets.

Compared to the third quarter of 2013, production increased 19% or 16,306 BOE/day. Natural gas volumes grew by approximately 30% due to our ongoing development activity in the Marcellus combined with the fourth quarter 2013 acquisition of additional working interests in our existing Marcellus properties. Over the same period, our crude oil volumes increased by approximately 4% due to growth in our Fort Berthold production volumes.

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

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

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2014**	**2013**	**% Change**	**2014**	**2013**	**% Change**
Crude oil (bbls/day)	40,332	38,883	4%	39,328	38,426	2%
Natural gas liquids (bbls/day)	3,869	2,985	30%	3,591	3,357	7%
Natural gas (Mcf/day)	359,007	275,164	30%	356,288	279,212	28%
Total daily sales (BOE/day)	104,035	87,729	19%	102,300	88,318	16%

Based on our year to date performance, we have revised our 2014 annual average production guidance to 102,000-104,000 BOE/day from 100,000-104,000 BOE/day. The lower end of the guidance range assumes ongoing production curtailments in the Marcellus throughout the fourth quarter. This guidance also includes the impact of the September 30, 2014 non-core asset disposition of 1,900 BOE/day and the divestment of non-core gas weighted properties with production of approximately 1,200 BOE/day in the fourth quarter.

Our crude oil and natural gas liquids production has been strong in October. We have just finished drilling and completing a five well pad in North Dakota that we expect to have tied-in by early November. We expect our crude oil and natural gas liquids production to increase to approximately 47,000 BOE/day for the fourth quarter and continue to expect average annual crude oil and natural gas liquids production to grow by 5% from 2013 to average 44,000 BOE/day.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, funds flow and financial condition. The following table compares the nine month period ended September 30, 2014 and 2013 and quarterly average prices from the third quarter of 2014 to the third quarter of 2013.

	Nine months ended September 30,						
Pricing (average for the period)	**2014**	**2013**	**Q3 2014**	**Q2 2014**	**Q1 2014**	**Q4 2013**	**Q3 2013**
Benchmarks							
WTI crude oil (US$/bbl)	$ 99.61	$ 98.14	$ 97.17	$ 102.99	$ 98.68	$ 97.46	$ 105.82
AECO natural gas – monthly index (CDN$/Mcf)	4.55	3.16	4.22	4.68	4.76	3.16	2.82
AECO natural gas – daily index (CDN$/Mcf)	4.81	3.05	4.02	4.69	5.71	3.53	2.43
NYMEX natural gas – last day (US$/Mcf)	4.55	3.67	4.06	4.67	4.94	3.60	3.58
US/CDN exchange rate	1.09	1.02	1.09	1.09	1.10	1.05	1.04
Enerplus selling price(1)							
Crude oil (CDN$/ bbl)	$ 90.91	$ 86.05	$ 86.49	$ 94.90	$ 91.48	$ 77.77	$ 96.30
Natural gas liquids (CDN$/ bbl)	53.01	51.48	44.85	49.98	66.30	54.26	49.88
Natural gas (CDN$/ Mcf)	4.04	3.26	3.22	4.02	4.93	3.26	2.96
Average differentials							
MSW Edmonton – WTI (US$/bbl)	$ (7.44)	$ (5.11)	$ (7.93)	$ (6.13)	$ (8.25)	$ (14.93)	$ (4.72)
WCS Hardisty – WTI (US$/bbl)	(21.12)	(22.86)	(20.18)	(20.04)	(23.13)	(32.20)	(17.48)
Brent Futures (ICE) – WTI (US$/bbl)	7.40	10.40	6.25	6.75	9.19	11.86	3.83
AECO monthly – NYMEX (US$/Mcf)	(0.40)	(0.62)	(0.18)	(0.38)	(0.63)	(0.60)	(0.86)
Enerplus realized differentials(1)							
Canada crude oil – WTI (US$/bbl)	$ (20.45)	$ (19.96)	$ (21.78)	$ (17.80)	$ (20.70)	$ (30.73)	$ (15.18)
Canada natural gas – NYMEX (US$/Mcf)	(0.54)	(0.77)	(0.55)	(0.71)	(0.31)	(0.63)	(1.06)
Bakken crude oil – WTI (US$/bbl)	(13.78)	(8.84)	(14.72)	(14.55)	(11.85)	(17.47)	(11.41)
Marcellus natural gas – NYMEX (US$/Mcf)	(1.38)	(0.25)	(1.72)	(1.50)	(0.88)	(0.50)	(0.52)

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

Crude Oil and Natural Gas Liquids

Our crude oil selling price decreased 9% from the prior quarter as a result of lower benchmark prices and widening differentials. WTI crude oil averaged US$97.17/bbl during the third quarter, down almost US$6.00/bbl from the previous period. Global prices declined steadily due to a combination of seasonal refinery turnarounds reducing demand and higher than anticipated global oil production, primarily in North America and Libya. WTI exited September at US$91.16/bbl and continued to weaken in the fourth quarter.

Light sweet crude oil differentials in Canada weakened considerably during the third quarter with mixed sweet blend (MSW) differentials averaging US$7.93/bbl below WTI as a result of continued apportionment on the Canadian pipeline systems decreasing takeaway capacity. The market continues to await the start of the Line 9 pipeline reversal from Sarnia, Ontario to Montreal, Quebec, which is now delayed until early 2015. Once operational, this reversal will provide access to refineries in Eastern Canada and may provide support for light sweet crude prices. In the US, delays in the startup of the Pony Express pipeline from Guernsey, Wyoming to Cushing, Oklahoma continued to restrict takeaway capacity and negatively impact our realized Bakken differentials in the field, which averaged US$14.72/bbl below WTI for the quarter. Western Canadian Select (WCS) heavy oil differentials remained steady at US$20.18/bbl below WTI but began to strengthen near the end of the quarter as the Flanagan South pipeline project from Pontiac, Illinois to Cushing, Oklahoma began purchasing line fill prior to start-up in the fourth quarter.

Natural Gas

Our selling price decreased 20% compared to the second quarter as a result of lower benchmark prices and widening differentials in the Marcellus region. U.S. natural gas prices continued to fall throughout the third quarter as a result of cooler than average summer weather. This led to significantly higher than expected storage injections across most regions and contributed to NYMEX prices falling by over US$0.60/Mcf, averaging US$4.06/Mcf in the third quarter.

In Canada, the AECO differential to NYMEX narrowed to US$0.18/Mcf below NYMEX during the third quarter, compared to US$0.38/Mcf in the second quarter, given the slower pace of storage refill in western Canada. We continue to maintain a balanced mix of AECO basis, month and day index price exposures in our Canadian gas portfolio, with our index exposure split almost evenly between month and day AECO indices.

Natural gas prices in the Marcellus continued to trade at a significant discount to NYMEX, as Marcellus and Utica production continued to outpace growth in pipeline takeaway capacity. Our production is priced primarily off of northeast Pennsylvania and Dominion South Point prices. Scheduled maintenance across a number of interstate pipelines resulted in volatility of spot prices throughout northeast Pennsylvania, with spot prices in the region averaging approximately US$2.00/Mcf below NYMEX for the quarter. With approximately 55% of our Marcellus production during the quarter exposed to spot prices in northeast Pennsylvania and approximately 36% exposed to Dominion South Point, we realized a Marcellus price differential of US$1.72/Mcf below NYMEX. We continue to expect wide differentials in the Marcellus for the remainder of the year, although new pipeline capacity coming on-stream on November 1, 2014 may provide some relief.

Foreign Exchange

The majority of our oil and gas sales are based on U.S. dollar denominated indices, and a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. After regaining some ground in the second quarter, the Canadian dollar weakened by nearly 5% in the third quarter and exited September near year to date lows. During the third quarter, we continued to enter into foreign exchange costless collars on our oil and gas sales to hedge a floor exchange rate on a portion of our U.S. dollar denominated oil and gas sales and to participate in some upside potential in the event the Canadian dollar continues to weaken.

As of October 22, 2014 we have US$26 million per month hedged for the remainder of 2014 at an average USD/CDN floor of 1.1064, ceiling of 1.1500 and conditional ceiling of 1.1212. For 2015, we have US$24 million per month hedged at an average USD/CDN floor of 1.1088, ceiling of 1.1845 and conditional ceiling of 1.1263. Under these contracts, if the monthly foreign exchange rate settles above the ceiling rate the conditional ceiling is used to determine the settlement amount. During the third quarter, we recorded cash gains of $0.6 million and non-cash mark-to-market losses of $8.7 million on these contracts.

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. During the third quarter and fourth quarter to date we continued to add risk management positions for both crude oil and natural gas. With the decline in crude oil prices we bought back the upside on a portion of our previously swapped crude oil volumes through costless upside participation collars. With respect to natural gas, we entered into additional swap positions for 2015 and 2016 to add more downside protection.

As of October 22, 2014, we have swapped approximately 64% of our forecasted net crude oil production for the remainder of 2014 at an average price of US$95.29/bbl. For the first and second half of 2015, we have swapped approximately 50% and 26%, respectively, of our forecasted net crude oil production at an average price of US$93.58/bbl, and US$93.86/bbl, respectively. In relation to a portion of the volumes swapped we have purchased call options to participate in price upside above US$94.00/bbl and sold put options at an average strike price of US$63.00/bbl, offsetting the call premium. We also have WCS and MSW differential swap positions to manage our exposure to Canadian crude oil differentials. We expect these contracts to protect a significant portion of our funds flow in the near term.

As of October 22, 2014, we have downside protection on approximately 49% and 28% of our forecasted net natural gas production after royalties for the remainder of 2014 and full year 2015, respectively, consisting of a combination of NYMEX swaps, NYMEX collars and AECO swaps.

The following is a summary of our financial contracts in place at October 22, 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)				
	Oct 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Dec 31, 2015	Oct 1, 2014 – Dec 31, 2014	Oct 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Mar 31, 2015	Apr 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Dec 31, 2015	Jan 1, 2016 – Dec 31, 2016
Downside Protection Swaps									
Sold Swaps	$ 95.29	$ 93.58	$ 93.86	$ 4.25	$ 4.14	$ 4.25	$ 4.25	$ 4.16	$ 4.03
%	64%	50%	26%	10%	28%	29%	29%	22%	4%
Downside Protection Collars									
Purchased Puts	–	–	–	–	$ 4.30	$ 4.53	–	–	–
%	–	–	–	–	11%	11%	–	–	–
Sold Calls	–	–	–	–	$ 5.08	$ 5.53	–	–	–
%	–	–	–	–	11%	11%	–	–	–
Upside Participation Collars									
Sold Puts	–	$ 63.00	$ 63.00	–	$ 3.23	$ 3.25	$ 3.25	$ 3.25	–
%	–	6%	6%	–	9%	2%	2%	2%	–
Sold Calls	–	–	–	–	$ 5.00	$ 5.00	$ 5.00	$ 5.00	–
%	–	–	–	–	9%	2%	2%	2%	–
Purchased Calls	–	$ 94.00	$ 94.00	–	$ 4.17	$ 4.29	$ 4.29	$ 4.29	–
%	–	6%	6%	–	9%	2%	2%	2%	–

(1) Based on weighted average price (before premiums), assumed average annual production of 102,000 – 104,000 BOE/day for 2014 and 2015, less royalties and production taxes of 23% in aggregate.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Risk Management Gains/(Losses) ($ millions)	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Cash gains/(losses):				
Crude oil	$ (4.2)	$ (12.9)	$ (36.2)	$ 9.0
Natural gas	1.7	2.3	(6.2)	1.1
Total cash gains/(losses)	$ (2.5)	$ (10.6)	$ (42.4)	$ 10.1
Non-cash gains/(losses):				
Change in fair value – crude oil	$ 82.9	$ (45.6)	$ 48.7	$ (66.5)
Change in fair value – natural gas	10.9	0.5	8.3	4.3
Total non-cash gains/(losses)	$ 93.8	$ (45.1)	$ 57.0	$ (62.2)
Total gains/(losses)	$ 91.3	$ (55.7)	$ 14.6	$ (52.1)

(Per BOE)	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Total cash gains/(losses)	$ (0.26)	$ (1.30)	$ (1.52)	$ 0.42
Total non-cash gains/(losses)	9.80	(5.60)	2.04	(2.58)
Total gains/(losses)	$ 9.54	$ (6.90)	$ 0.52	$ (2.16)

During the third quarter we realized cash losses of $4.2 million on our crude oil contracts and cash gains of $1.7 million on our natural gas contracts. In comparison, during the third quarter of 2013, we realized cash losses of $12.8 million on our crude oil contracts and cash gains of $2.3 million on our natural gas contracts. The cash losses realized in 2014 and 2013 were a result of crude oil prices rising above our fixed price swap positions, while cash gains were due to natural gas contracts that provided floor protection above market prices.

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At the end of the third quarter of 2014, the fair value of our crude oil and natural gas contracts represented net gain positions of $33.8 million and $8.6 million, respectively. For the three and nine months ended September 30, 2014 the change in the fair value of our crude oil contracts represented gains of $82.9 million and $48.7 million, respectively, while the change in fair value of our natural gas contracts represented gains of $10.9 million and $8.3 million, respectively.

Revenues

($ millions)	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Oil and natural gas sales	$ 456.2	$ 441.5	$ 1,455.8	$ 1,219.8
Royalties	(77.9)	(76.1)	(254.8)	(199.7)
Oil and natural gas sales, net of royalties	$ 378.3	$ 365.4	$ 1,201.0	$ 1,020.1

Oil and natural gas sales were $456.2 million in the third quarter of 2014, an increase of 3% or $14.7 million compared to the same period in 2013. For the nine months ended September 30, 2014, oil and natural gas sales were $1,455.8 million, an increase of 19% or $236.0 million compared to the same period a year ago. The increase in revenues was driven primarily by year over year production growth. Although crude oil and natural gas liquids selling prices were lower during the quarter compared to the same period in 2013, improved pricing in the first half of the year led to an overall improvement in realized prices year to date.

Royalties and Production Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2014	2013	2014	2013
Royalties	$ 77.9	$ 76.1	$ 254.8	$ 199.7
Production taxes	21.3	20.0	61.1	52.5
Royalties and production taxes	$ 99.2	$ 96.1	$ 315.9	$ 252.2
As a % of oil and natural gas sales, net of transportation	22%	22%	22%	21%

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2014	2013	2014	2013
Royalties	$ 8.14	$ 9.43	$ 9.12	$ 8.27
Production taxes	2.22	2.48	2.19	2.19
Royalties and production taxes	$ 10.36	$ 11.91	$ 11.31	$ 10.46
As a % of oil and natural gas sales, net of transportation	22%	22%	22%	21%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. During the three and nine months ended September 30, 2014 royalties and production taxes increased to $99.2 million and $315.9 million, respectively, from $96.1 million and $252.2 million for the same periods in 2013. This upward trend is primarily due to increased production from higher royalty rate U.S. properties. As a percentage of oil and gas sales, net of transportation costs, royalties and production taxes averaged 22% for the three and nine months ended September 30, 2014 compared to 22% and 21%, respectively, for the same periods in 2013.

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

Operating Expenses

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2014	2013	2014	2013
Operating Expenses	$ 102.1	$ 85.5	$ 286.7	$ 252.3
Per BOE	$ 10.67	$ 10.60	$ 10.27	$ 10.46

Operating expenses for the three and nine months ended September 30, 2014 were $102.1 million or $10.67/BOE and $286.7 million or $10.27/BOE, respectively. In comparison, operating costs were $85.5 million or $10.60/BOE and $252.3 million or $10.46/BOE for the same periods in 2013.

The production curtailments at our lower operating cost Marcellus properties negatively impacted operating costs on a per BOE basis during the quarter. Seasonal well servicing and higher repairs and maintenance costs also increased our operating costs in the third quarter.

Based on ongoing production curtailments in the Marcellus in the fourth quarter we have revised our 2014 guidance to $10.25/BOE from $10.10/BOE, consistent with our original guidance for 2014.

Transportation Costs

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2014	2013	2014	2013
Transportation costs	$ 14.7	$ 8.8	$ 40.9	$ 22.3
Per BOE	$ 1.53	$ 1.09	$ 1.46	$ 0.92

Transportation costs for the three and nine months ended September 30, 2014 were $14.7 million or $1.53/BOE and $40.9 million or $1.46/BOE, respectively, compared to $8.8 million or $1.09/BOE and $22.3 million or $0.92/BOE for the same periods in 2013. The increase from the prior year was related to higher U.S. production as well as costs associated with securing U.S. pipeline capacity.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three and nine months ended September 30, 2014 and 2013. The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A. Certain prior period amounts have been reclassified to conform with current period presentation.

	Three months ended September 30, 2014		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	45,263 BOE/day	352,632 Mcfe/day	104,035 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 80.15	$ 3.32	$ 46.13
Royalties and production taxes	(20.73)	(0.40)	(10.36)
Cash operating costs	(13.13)	(1.46)	(10.67)
Netback before hedging	$ 46.29	$ 1.46	$ 25.10
Cash gains/(losses)	(1.01)	0.05	(0.26)
Netback after hedging	$ 45.28	$ 1.51	$ 24.84
Netback before hedging ($ millions)	$ 192.8	$ 47.5	$ 240.3
Netback after hedging ($ millions)	$ 188.6	$ 49.2	$ 237.8

	Three months ended September 30, 2013		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	43,670 BOE/day	264,354 Mcfe/day	87,729 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 88.44	$ 3.18	$ 53.61
Royalties and production taxes	(20.74)	(0.53)	(11.91)
Cash operating costs	(12.26)	(1.49)	(10.58)
Netback before hedging	$ 55.44	$ 1.16	$ 31.12
Cash gains/(losses)	(3.20)	0.10	(1.30)
Netback after hedging	$ 52.24	$ 1.26	$ 29.82
Netback before hedging ($ millions)	$ 222.7	$ 28.5	$ 251.2
Netback after hedging ($ millions)	$ 209.9	$ 30.8	$ 240.6

Netbacks by Property Type	Nine months ended September 30, 2014 Crude Oil	Natural Gas	Total
Average Daily Production	44,317 BOE/day	347,898 Mcfe/day	102,300 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 84.18	$ 4.17	$ 50.66
Royalties and production taxes	(21.08)	(0.64)	(11.31)
Cash operating costs	(12.78)	(1.39)	(10.28)
Netback before hedging	$ 50.32	$ 2.14	$ 29.07
Cash gains/(losses)	(2.99)	(0.07)	(1.52)
Netback after hedging	$ 47.33	$ 2.07	$ 27.55
Netback before hedging ($ millions)	$ 608.9	$ 203.2	$ 812.1
Netback after hedging ($ millions)	$ 572.7	$ 197.0	$ 769.7

Netbacks by Property Type	Nine months ended September 30, 2013 Crude Oil	Natural Gas	Total
Average Daily Production	43,447 BOE/day	269,226 Mcfe/day	88,318 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 78.41	$ 3.64	$ 49.67
Royalties and production taxes	(18.37)	(0.47)	(10.46)
Cash operating costs	(12.25)	(1.47)	(10.52)
Netback before hedging	$ 47.79	$ 1.70	$ 28.69
Cash gains/(losses)	0.76	0.02	0.42
Netback after hedging	$ 48.55	$ 1.72	$ 29.11
Netback before hedging ($ millions)	$ 566.8	$ 125.0	$ 691.8
Netback after hedging ($ millions)	$ 575.8	$ 126.1	$ 701.9

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

Our crude oil properties accounted for 75% of our corporate netback before hedging for the year to date compared to 82% for the same period in 2013. Crude oil netbacks per BOE before hedging decreased during the three months ended September 30, 2014 compared to the same period in 2013 primarily due to lower realized crude oil prices. For the nine months ended September 30, 2014 average realized crude oil prices were higher than the same period in 2013 which resulted in higher crude oil netbacks before hedging compared to the previous year. Natural gas netbacks per Mcfe before hedging increased for the three and nine months ended compared to the same period last year primarily due to the increase in realized natural gas prices from 2013.

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 September 30,				Nine months ended September 30,			
($ millions)		2014		2013		2014		2013
Cash:								
G&A expense[1]	$	18.9	$	20.0	$	58.1	$	63.5
SBC expense/(recovery)		(5.2)		4.9		12.3		14.1
Non-Cash:								
SBC		3.4		1.7		9.9		7.2
SBC – equity swap loss/(gain)		5.8		(1.5)		(0.1)		(3.8)
Total G&A expenses	$	22.9	$	25.1	$	80.2	$	81.0

	Three months ended September 30,				Nine months ended September 30,			
(Per BOE)		2014		2013		2014		2013
Cash:								
G&A expense[1]	$	1.97	$	2.48	$	2.08	$	2.63
SBC expense/(recovery)		(0.54)		0.60		0.44		0.58
Non-Cash:								
SBC		0.36		0.21		0.35		0.30
SBC – equity swap loss/(gain)		0.61		(0.18)		–		(0.16)
Total G&A expenses	$	2.40	$	3.11	$	2.87	$	3.35

(1) Excluding SBC.

Cash G&A expenses during the third quarter were $18.9 million or $1.97/BOE compared to $20.0 million or $2.48/BOE in the third quarter of 2013. For the nine months ended September 30, 2014 cash G&A expenses were $58.1 million or $2.08/BOE compared to $63.5 million or $2.63/BOE for the same period in 2013. The decrease during 2014 was partially due to one-time charges recorded in the prior year associated with the departure of personnel, while higher production volumes in 2014 also contributed to a decrease in our reported G&A on a per BOE basis. We are maintaining our cash G&A guidance at $2.30/BOE for the year.

Our share price decreased by 21% during the quarter, reducing our cash SBC expense and resulting in a recovery of $5.2 million or $0.54/BOE compared to a charge of $4.9 million or $0.60/BOE during the third quarter of 2013. For the nine months ended September 30, 2014 cash SBC expense was $12.3 million or $0.44/BOE compared to $14.1 million or $0.58/BOE for the same period in the prior year.

We have hedged a portion of the outstanding cash settled units under our LTI plans at an average price of $14.92/share. As a result of the decrease in our share price we recorded a non-cash mark-to-market loss of $5.8 million for the quarter and a gain of $0.1 million for the nine months ended September 30, 2014.

Based on our September 30, 2014 share price of $21.26 we have revised our 2014 guidance for cash SBC to $0.45/BOE from $0.60/BOE.

Interest Expense

	Three months ended September 30,				Nine months ended September 30,			
($ millions)		2014		2013		2014		2013
Interest on senior notes and bank facility	$	14.9	$	14.7	$	45.5	$	43.1
Non-cash interest expense		0.3		0.4		1.4		1.2
Total interest expense	$	15.2	$	15.1	$	46.9	$	44.3

For the three and nine months ended September 30, 2014 we recorded total interest expense of $15.2 million and $46.9 million, respectively, compared to $15.1 million and $44.3 million in the same periods in 2013.

Interest expense increased marginally for the three and nine months ended September 30, 2014 compared to the same periods in 2013 mainly due to the impact of a weaker Canadian dollar on our U.S. dollar denominated interest payments.

At September 30, 2014, after including our underlying derivatives, approximately 95% of our debt was based on fixed interest rates and 5% on floating interest rates, with weighted average interest rates of 5.28% and 2.92%, respectively. The percentage of fixed rate debt has increased from prior periods as we closed our US$200.0 million senior notes offering on September 3, 2014 and used the proceeds to pay down bank debt.

Foreign Exchange

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2014	2013	2014	2013
Realized loss/(gain)	$ (2.6)	$ 0.1	$ 14.0	$ 17.7
Unrealized loss/(gain)	33.1	(2.6)	10.7	(13.7)
Total foreign exchange loss/(gain)	$ 30.5	$ (2.5)	$ 24.7	$ 4.0

We recorded a net foreign exchange loss of $30.5 million during the third quarter and a loss of $24.7 million year to date, compared to a net gain of $2.5 million and a net loss of $4.0 million, respectively, during the same periods in 2013.

Realized gains during the quarter resulted from foreign exchange gains on day-to-day transactions denominated in foreign currencies. Unrealized foreign exchange losses related to the translation of our U.S. dollar denominated debt and working capital.

Capital Investment and Dispositions

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2014	2013	2014	2013
Capital spending	$ 207.8	$ 145.8	$ 630.0	$ 458.4
Office capital	1.4	1.2	3.0	3.4
Sub-total	$ 209.2	$ 147.0	$ 633.0	$ 461.8
Property and land acquisitions	$ 4.0	$ 15.8	$ 17.2	$ 71.5
Property dispositions	(68.9)	(124.5)	(185.6)	(197.1)
Sub-total	$ (64.9)	$ (108.7)	$ (168.4)	$ (125.6)
Total net capital investment	$ 144.3	$ 38.3	$ 464.6	$ 336.2

Capital spending for the third quarter totaled $207.8 million compared to $145.8 million during the same period in 2013. We continue to focus our spending on our core development areas with 64% directed towards crude oil development. Crude oil spending for the quarter included $95.7 million at Fort Berthold and $37.0 million on our Canadian waterflood properties. Natural gas spending included $56.6 million in the Marcellus and $16.1 million on our Deep Basin assets.

During the quarter we had minor property and land acquisitions totaling $4.0 million, of which $2.0 million related to undeveloped land acquisitions in our Deep Basin properties and $2.0 million related to additional land interests around our existing Marcellus acreage. In the third quarter of 2013 we spent $15.8 million which included $6.4 million for additional land interests in the Deep Basin, $7.5 million in Fort Berthold and $1.9 million in the Marcellus.

On September 30, 2014, we divested of $69.0 million of non-core natural gas properties in the Deep Basin area with production of approximately 1,900 BOE/day. During the quarter, we also entered into an agreement to sell additional non-core Canadian natural gas properties with production of approximately 1,200 BOE/day for net proceeds of approximately $22.0 million. This transaction closed in early November. Combined, we expect to realize approximately $30,000 per flowing barrel on these non-core gas divestments.

Property dispositions during the third quarter of 2013 totaled $124.5 million which included non-core Canadian properties primarily in Saskatchewan and Alberta for proceeds of $89.3 million as well as certain facilities in Fort Berthold for proceeds of $35.2 million.

Our successful non-core divestments have allowed us to increase our capital spending program and redeploy a portion of the proceeds to accelerate our 2015 capital spending programs in Fort Berthold and the Wilrich. As a result, we have increased our capital spending guidance for the year to $830 million from $800 million.

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

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2014	2013	2014	2013
DDA&A expense	$ 159.7	$ 163.3	$ 440.5	$ 470.1
Per BOE	$ 16.68	$ 20.24	$ 15.77	$ 19.50

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three and nine months ended September 30, 2014 DDA&A decreased to $159.7 million and $440.5 million, respectively, compared to $163.3 million and $470.1 million during the same periods in 2013. The decrease was primarily due to significant reserve additions for the year ended December 31, 2013 that lowered our depletion rate for 2014.

Asset Retirement Obligation

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are estimated 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 $286.7 million at September 30, 2014 compared to $291.8 million at December 31, 2013.

Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2014	2013	2014	2013
Current tax expense	$ –	$ 5.2	$ 11.4	$ 7.9
Deferred tax expense/(recovery)	36.9	(6.6)	74.1	15.6
Total tax expense/(recovery)	$ 36.9	$ (1.4)	$ 85.5	$ 23.5

For the three and nine months ended September 30, 2014, we recorded a total tax expense of $36.9 million and $85.5 million respectively, compared to a $1.4 million tax recovery and a $23.5 million tax expense in the same periods in 2013. The increase in our total tax expense is due to higher net 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. Given the decrease in commodity prices and resulting decrease in forecasted net income for the year, a current tax accrual was not needed during the third quarter. Based on current commodity prices and assuming no acquisitions and divestiture activity, we expect to pay U.S. cash taxes of approximately 2% of our U.S. funds flow in 2014, and approximately 3% – 5% from 2015 to 2018. We currently do not expect to pay material cash taxes in Canada until after 2018.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

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

(millions, except per unit amounts)	Three months ended September 30, 2014			Three months ended September 30, 2013		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	16,837	23,495	40,332	17,246	21,637	38,883
Natural gas liquids (bbls/day)	2,578	1,291	3,869	2,265	720	2,985
Natural gas (Mcf/day)	154,855	204,152	359,007	174,169	100,995	275,164
Total average daily production (BOE/day)	45,224	58,811	104,035	48,539	39,190	87,729
Pricing[2]						
Crude oil (per bbl)	$ 82.11	$ 89.63	$ 86.49	$ 94.12	$ 98.04	$ 96.30
Natural gas liquids (per bbl)	46.28	42.01	44.85	58.64	22.31	49.88
Natural gas (per Mcf)	3.82	2.77	3.22	2.62	3.55	2.96
Capital Expenditures						
Capital spending	$ 55.2	$ 152.6	$ 207.8	$ 57.0	$ 88.8	$ 145.8
Acquisitions	2.0	2.0	3.9	6.4	9.4	15.8
Dispositions	(68.9)	0.0	(68.9)	(89.3)	(35.2)	(124.5)
Netback Before Hedging						
Oil and natural gas sales	$ 199.3	$ 256.9	$ 456.2	$ 209.6	$ 231.9	$ 441.5
Royalties	(27.1)	(50.8)	(77.9)	(31.6)	(44.5)	(76.1)
Cash operating expense	(64.7)	(37.3)	(102.0)	(62.2)	(23.2)	(85.4)
Production taxes	(2.5)	(18.8)	(21.3)	(1.4)	(18.6)	(20.0)
Transportation expense	(6.2)	(8.5)	(14.7)	(5.5)	(3.3)	(8.8)
Netback before hedging	$ 98.8	$ 141.5	$ 240.3	$ 108.9	$ 142.3	$ 251.2
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (91.3)	$ –	$ (91.3)	$ 55.7	$ –	$ 55.7
General and administrative expense	19.8	3.1	22.9	20.7	4.4	25.1
Current income tax expense/(recovery)	(0.1)	0.1	–	(0.3)	5.5	5.2

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

(millions, except per unit amounts)	Nine months ended September 30, 2014 Canada	U.S.	Total	Nine months ended September 30, 2013 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	16,867	22,461	39,328	18,253	20,173	38,426
Natural gas liquids (bbls/day)	2,531	1,060	3,591	2,782	575	3,357
Natural gas (Mcf/day)	154,306	201,982	356,288	179,503	99,709	279,212
Total average daily production (BOE/day)	45,116	57,184	102,300	50,952	37,366	88,318
Pricing[2]						
Crude oil (per bbl)	$ 87.05	$ 93.81	$ 90.91	$ 80.02	$ 91.50	$ 86.05
Natural gas liquids (per bbl)	57.37	42.60	53.01	56.59	26.77	51.48
Natural gas (per Mcf)	4.41	3.76	4.04	2.97	3.78	3.26
Capital Expenditures						
Capital spending	$ 243.2	$ 386.8	$ 630.0	$ 184.4	$ 274.0	$ 458.4
Acquisitions	2.0	15.2	17.2	44.0	27.5	71.5
Dispositions	(136.6)	(49.0)	(185.6)	(154.5)	(42.6)	(197.1)
Netback Before Hedging						
Oil and natural gas sales	$ 645.3	$ 810.5	$ 1,455.8	$ 606.7	$ 613.1	$ 1,219.8
Royalties	(96.2)	(158.6)	(254.8)	(82.1)	(117.6)	(199.7)
Cash operating expense	(189.1)	(97.8)	(286.9)	(193.6)	(60.0)	(253.6)
Production taxes	(6.4)	(54.7)	(61.1)	(7.8)	(44.7)	(52.5)
Transportation expense	(17.9)	(23.0)	(40.9)	(17.3)	(4.9)	(22.2)
Netback before hedging	$ 335.7	$ 476.4	$ 812.1	$ 305.9	$ 385.9	$ 691.8
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (14.6)	$ –	$ (14.6)	$ 52.1	$ –	$ 52.1
General and administrative expense	65.7	14.5	80.2	69.4	11.6	81.0
Current income tax expense/(recovery)	(0.5)	11.9	11.4	(0.3)	8.2	7.9

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

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	Diluted
2014				
Third Quarter	$ 378.3	$ 67.4	$ 0.33	$ 0.32
Second Quarter	414.9	40.0	0.20	0.19
First Quarter	407.7	40.0	0.20	0.19
Total	$ 1,200.9	$ 147.4	$ 0.73	$ 0.70
2013				
Fourth Quarter	$ 332.4	$ 29.6	$ 0.15	$ 0.15
Third Quarter	365.4	(3.7)	(0.02)	(0.02)
Second Quarter	341.3	38.5	0.19	0.19
First Quarter	313.4	(16.4)	(0.08)	(0.08)
Total	$ 1,352.5	$ 48.0	$ 0.24	$ 0.24
2012				
Fourth Quarter	$ 310.2	$ 34.6	$ 0.18	$ 0.18
Third Quarter	279.3	(88.6)	(0.45)	(0.45)
Second Quarter	274.3	(41.9)	(0.21)	(0.21)
First Quarter	289.5	(174.8)	(0.92)	(0.92)
Total	$ 1,153.3	$ (270.7)	$ (1.38)	$ (1.38)

Oil and gas sales, net of royalties, increased in 2014 compared to 2013 primarily due to increased production and higher realized commodity prices. In the third quarter of 2014 lower realized commodity prices resulted in lower oil and gas sales for the quarter. Throughout 2013 and 2012 oil and gas sales, net of royalties, generally increased with higher production although volatile commodity prices caused some fluctuations.

Net income for 2014 benefited from higher production and generally higher realized prices offset by fluctuating risk management costs and foreign exchange gains and losses. Net income for 2013 and 2012 was impacted by fluctuating risk management costs, asset impairment charges and gains on marketable security divestments.

LIQUIDITY AND CAPITAL RESOURCES

We continued to maintain a strong balance sheet and ample liquidity through the third quarter. At September 30, 2014 we had a conservative trailing 12 month debt to cash flow ratio of 1.3x. On September 3, 2014 we closed a private placement of US$200.0 million of senior unsecured notes, with a twelve year amortizing term, a ten year average life and a fixed interest rate of 3.79%. The proceeds were used to repay our short-term, floating interest rate bank debt, and as a result we had $942.5 million of undrawn capacity on our $1 billion credit facility at quarter end.

Our adjusted payout ratio, calculated as dividends (net of SDP proceeds) plus capital and office spending, divided by funds flow, increased to 122% and 120% for the three and nine months ended September 30, 2014, respectively, compared to 97% and 103% for the same periods in 2013. Although funds flow increased by 8% and 13% for the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013, we saw a proportionately larger increase in our capital spending program and a decrease in our SDP participation over the same period. Despite the increase in adjusted payout ratio, the health of our balance sheet has been maintained in part due to the success of our non-core asset divestment program.

We continue to hedge a portion of our commodity price risk and expect our risk management program to provide funds flow protection in the near term. At September 30, 2014 we had approximately 64% of our anticipated remaining 2014 crude oil production hedged at a price of $95.29, and approximately 38% of our anticipated 2015 oil production hedged at $93.68.

Total debt net of cash at September 30, 2014 was $1,091.1 million compared to $1,022.3 million at December 31, 2013. Total debt was comprised of $57.5 million of bank indebtedness and $1,035.7 million of senior notes, less $2.1 million in cash. A significant portion of our senior notes are denominated in U.S. dollars and given the weakening Canadian dollar our total reported debt has increased. Our working capital deficiency, excluding cash and current deferred financial and tax assets and credits, increased slightly during the quarter to $252.5 million from $251.2 million in the second 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	September 30, 2014	December 31, 2013
Long-term debt to funds flow (trailing 12-month)(1)	1.3 x	1.4 x
Funds flow to interest expense (trailing 12-month)(2)	14.0 x	13.3 x
Long-term debt to long-term debt plus equity(1)	35%	35%

(1) Long-term debt is measured net of cash and includes the current portion of the senior notes.

(2) Interest expense excluding non-cash items.

At September 30, 2014 we were in compliance with all covenants under our bank credit facility and senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com and on the EDGAR website at www.sec.gov.

Dividends

($ millions, except per share amounts)	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Cash dividends	$ 51.1	$ 42.4	$ 143.8	$ 128.7
Stock dividend plan	4.3	12.0	21.8	33.5
Total dividends to shareholders	$ 55.4	$ 54.4	$ 165.6	$ 162.2
Per weighted average share (Basic)	$ 0.27	$ 0.27	$ 0.81	$ 0.81

During the three and nine months ended September 30, 2014 we maintained our monthly $0.09/share dividend, resulting in dividends to shareholders of $55.4 million ($0.27/share) and $165.6 million ($0.81/share), respectively, compared to $54.5 million ($0.27/share) and $162.2 million ($0.81/share) for the same periods in 2013. For the first nine months of 2014, dividend payments including SDP amounted to 26% of our funds flow of $646.5 million. We continue to monitor 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.

Effective September 19, 2014 the Board of Directors elected to suspend the SDP in an effort to eliminate the dilution associated with the issuance of shares through the plan. Effective with the October 2014 dividend, all dividends will be paid in cash on or about the 15th day of the month, approximately five days earlier than previously. All record dates and ex-dividend dates will also be adjusted accordingly with future record dates being on or about the last business day of the previous calendar month.

Commitments

During the third quarter we acquired additional transportation commitments for 11.1 MMcf/day on various pipelines in the Marcellus region. These contracts relate to the additional working interest acquisition at the end of 2013 and have various terms extending out to 2020, 2028 and 2033 and comprise a total commitment of approximately US$54.3 million.

Shareholders' Capital

	Nine months ended September 30, 2014	2013
Share capital ($ millions)	$ 3,115.5	$ 3,046.1
Common shares outstanding (thousands)	205,423	201,873
Weighted average shares outstanding – basic (thousands)	204,174	200,002
Weighted average shares outstanding – diluted (thousands)	207,970	200,415

During the third quarter of 2014, a total of 655,000 shares (2013 – 1,605,000) and $12.2 million of additional equity (2013 – $26.9 million) was issued pursuant to the SDP and the stock option plan. For the nine months ended September 30, 2014, a total of 2,665,000 shares (2013 – 3,189,000) and $48.9 million of additional equity (2013 – $48.4 million) was issued pursuant to the SDP and the stock option plan.

At September 30, 2014 we had 205,423,000 shares outstanding (2013 – 201,874,000) and at November 6, 2014 we had 205,434,022 shares outstanding.

2014 GUIDANCE

A summary of our 2014 guidance is below.

Summary of 2014 Expectations	Target
Average annual production	102,000 – 104,000 BOE/day (from 100,000 – 104,000 BOE/day)
Production mix (volumes)	44,000 BOE/day crude oil and natural gas liquids 58,000-60,000 BOE/day natural gas (from 56,000-60,000 BOE/day)
Capital spending	$830 million (from $800 million)
Average royalty rate (% of gross sales, net of transportation)	23%
Operating costs	$10.25/BOE (from $10.10/BOE)
Cash G&A expenses	$2.30/BOE
Cash share-based compensation expenses	$0.45/BOE (from $0.60/BOE)
U.S. Cash taxes (% of U.S. funds flow)	2% (from 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 September 30, 2014, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on July 1, 2014 and ending September 30, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

*This MD&A contains certain forward-looking information and forward-looking statements within the meaning of applicable securities laws ("**forward-looking information**"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected 2014 and 2015 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged; the results from our drilling program and the timing of related production; future oil and natural gas prices and differentials and our commodity risk management programs; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash and non-cash G&A, share-based compensation and financing expenses; operating costs; capital spending levels in 2014 and its impact on our production level; potential future asset impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes and regular U.S. taxes; future debt and working capital levels and debt-to-funds-flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; the amount and timing of future cash dividends that we may pay to our shareholders; and future dispositions, including expected proceeds therefrom and production volumes associated therewith.*

The forward-looking information contained in this MD&A reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and resource volumes; commodity price and cost assumptions; the continued availability of adequate debt and/or equity financing and funds flow to fund our capital, operating and working capital requirements, *and dividend payments as needed; the continued availability and sufficiency of our funds flow and availability under our bank credit facility to fund our working capital deficiency; the availability of third party services; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.*

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: changes in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inaccurate estimation of our oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; a failure to complete planned asset dispositions on the terms anticipated or at all; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in this MD&A and in our other public filings).

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

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	September 30, 2014	December 31, 2013
Assets			
Current assets			
Cash		$ 2,104	$ 2,990
Accounts receivable	3	197,576	165,091
Deferred income tax asset		–	48,476
Deferred financial assets	15	40,906	9,198
Other current assets		12,651	7,641
		253,237	233,396
Property, plant and equipment			
Oil and natural gas properties (full cost method)	4	2,528,493	2,420,144
Other capital assets, net	4	18,862	21,210
Property, plant and equipment		2,547,355	2,441,354
Goodwill		618,521	609,975
Deferred income tax asset		356,955	364,411
Deferred financial assets	15	32,288	19,274
Marketable securities	5	–	13,389
Total Assets		$ 3,808,356	$ 3,681,799
Liabilities			
Current liabilities			
Accounts payable	6	$ 347,268	$ 377,157
Dividends payable		18,488	18,250
Current portion of long-term debt	7	96,937	48,713
Deferred income tax liability		6,640	–
Deferred financial credits	15	–	37,031
		469,333	481,151
Long-term debt	7	996,277	976,585
Asset retirement obligation	8	286,748	291,761
		1,283,025	1,268,346
Total Liabilities		1,752,358	1,749,497
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value Issued and outstanding: September 30, 2014 – 205 million shares December 31, 2013 – 203 million shares	14	3,115,527	3,061,839
Paid-in capital	14	43,522	38,398
Accumulated deficit		(1,135,401)	(1,117,238)
Accumulated other comprehensive income/(loss)		32,350	(50,697)
		2,055,998	1,932,302
Total Liabilities & Equity		$ 3,808,356	$ 3,681,799
Contingencies and Commitments	16		

See accompanying notes to the Condensed Consolidated Financial Statements

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

(CDN$ thousands, except per share amounts) unaudited	Note	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Revenues					
Oil and natural gas sales, net of royalties	9	$ 378,332	$ 365,391	$ 1,200,997	$ 1,020,096
Commodity derivative instruments gain/(loss)	15	91,268	(55,674)	14,602	(52,107)
		469,600	309,717	1,215,599	967,989
Expenses					
Operating		102,093	85,548	286,683	252,262
Production taxes		21,270	20,004	61,116	52,486
Transportation		14,667	8,830	40,915	22,259
General and administrative	10	22,937	25,114	80,240	80,989
Depletion, depreciation, amortization and accretion		159,658	163,339	440,494	470,088
Interest	11	15,175	15,084	46,876	44,321
Foreign exchange (gain)/loss	12	30,498	(2,509)	24,742	4,027
Other expense/(income)		(953)	(548)	1,599	(264)
		365,345	314,862	982,665	926,168
Income/(Loss) Before Taxes		104,255	(5,145)	232,934	41,821
Current income tax expense/(recovery)	13	(28)	5,235	11,447	7,943
Deferred income tax expense/(recovery)	13	36,853	(6,660)	74,063	15,528
Net Income/(Loss)		$ 67,430	$ (3,720)	$ 147,424	$ 18,350
Other Comprehensive Income/(Loss)					
Changes due to marketable securities (net of tax)					
Unrealized gain/(loss)		–	2,244	(145)	5,104
Realized (gain)/loss reclassified to net income		–	(125)	2,503	(315)
Change in cumulative translation adjustment		78,459	(24,307)	80,689	34,336
Other Comprehensive Income/(Loss)		78,459	(22,188)	83,047	39,125
Total Comprehensive Income/(Loss)		$ 145,889	$ (25,908)	$ 230,471	$ 57,475
Net Income/(Loss) per Share					
Basic	14	$ 0.33	$ (0.02)	$ 0.72	$ 0.09
Diluted	14	$ 0.32	$ (0.02)	$ 0.71	$ 0.09

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Changes in Shareholders' Equity

Nine months ended September 30, (CDN$ thousands) unaudited	**2014**	**2013**
Share Capital		
Balance, beginning of year	$ 3,061,839	$ 2,997,682
Stock Option Plan – cash	27,068	12,723
Share-based compensation – non-cash	4,783	2,222
Stock Dividend Plan	21,837	33,489
Balance, end of period	$ 3,115,527	$ 3,046,116
Paid-in Capital		
Balance, beginning of year	$ 38,398	$ 32,293
Stock Option Plan – exercised	(4,783)	(2,222)
Share-based compensation – expensed	9,907	7,164
Balance, end of period	$ 43,522	$ 37,235
Accumulated Deficit		
Balance, beginning of year	$ (1,117,238)	$ (948,350)
Net income	147,424	18,350
Dividends	(165,587)	(162,199)
Balance, end of period	$ (1,135,401)	$ (1,092,199)
Accumulated Other Comprehensive Income/(Loss)		
Balance, beginning of year	$ (50,697)	$ (130,385)
Changes due to marketable securities (net of tax)		
Unrealized gains/(losses)	(145)	5,104
Realized (gains)/losses reclassified to net income	2,503	(315)
Change in cumulative translation adjustment	80,689	34,336
Balance, end of period	$ 32,350	$ (91,260)
Total Shareholders' Equity	$ 2,055,998	$ 1,899,892

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Note	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Operating Activities					
Net income/(loss)		$ 67,430	$ (3,720)	$ 147,424	$ 18,350
Non-cash items add/(deduct):					
Depletion, depreciation, amortization and accretion		159,658	163,339	440,494	470,088
Changes in fair value of derivative instruments	15	(88,689)	48,950	(81,750)	35,061
Deferred income tax expense/(recovery)	13	36,853	(6,660)	74,063	15,528
Foreign exchange (gain)/loss on debt and working capital	12	33,863	(7,446)	35,798	9,092
Share-based compensation	14	3,413	1,686	9,907	7,164
Amortization of debt issue costs		251	188	744	565
Derivative settlement on senior notes		–	–	17,024	18,011
Asset disposition (gain)/loss		–	(150)	2,798	(367)
Asset retirement obligation expenditures	8	(3,299)	(3,701)	(11,831)	(10,036)
Changes in non-cash operating working capital	17	(10,435)	25,684	(66,710)	11,372
Cash flow from operating activities		199,045	218,170	567,961	574,828
Financing Activities					
Proceeds from the issuance of shares		7,875	12,694	27,068	12,723
Cash dividends	14	(51,088)	(42,411)	(143,750)	(128,710)
Change in bank debt		(236,013)	(144,858)	(159,303)	(74,769)
Issuance (repayment) of senior notes		217,460	–	179,562	(35,655)
Derivative settlement on senior notes		–	–	(17,024)	(18,011)
Changes in non-cash financing working capital		34	137	238	288
Cash flow from financing activities		(61,732)	(174,438)	(113,209)	(244,134)
Investing Activities					
Capital expenditures		(209,197)	(146,997)	(633,013)	(461,838)
Property and land acquisitions		(3,986)	(15,792)	(17,186)	(71,451)
Property dispositions		68,931	124,462	185,631	197,086
Sale of marketable securities	5	–	599	13,300	2,482
Changes in non-cash investing working capital		5,116	(145)	(5,689)	20,590
Cash flow from investing activities		(139,136)	(37,873)	(456,957)	(313,131)
Effect of exchange rate changes on cash		1,929	1,696	1,319	(4,452)
Change in cash		106	7,555	(886)	13,111
Cash, beginning of period		1,998	10,756	2,990	5,200
Cash, end of period		$ 2,104	$ 18,311	$ 2,104	$ 18,311

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 November 6, 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") as at September 30, 2014 and for the three and nine months ended September 30, 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.

Recent Accounting Pronouncements

Enerplus will adopt the following Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board, which have been issued but are not yet effective. The adoption of these standards is not expected to have a material impact on Enerplus' financial statements.

- ASU 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* – effective January 1, 2015
- ASU 2014-09, *Revenue from Contracts with Customers* – effective January 1, 2017
- ASU 2014-12, *Compensation – Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period* – effective January 1, 2016

3) ACCOUNTS RECEIVABLE

($ thousands)	September 30, 2014	December 31, 2013
Accrued receivables	$ 140,394	$ 122,482
Accounts receivable – trade	43,613	36,034
Current income tax receivable	16,424	9,371
Allowance for doubtful accounts	(2,855)	(2,796)
Total accounts receivable	$ 197,576	$ 165,091

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

As at September 30, 2014 ($ thousands)	**Cost**	**Accumulated Depletion and Depreciation**	**Net Book Value**
Oil and natural gas properties	$ 12,152,423	$ 9,623,930	$ 2,528,493
Other capital assets	93,474	74,612	18,862
Total PP&E	$ 12,245,897	$ 9,698,542	$ 2,547,355

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 nine months ended September 30, 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.

6) ACCOUNTS PAYABLE

($ thousands)	**September 30, 2014**	**December 31, 2013**
Accrued payables	$ 266,120	$ 262,117
Accounts payable – trade	81,148	115,040
Total accounts payable	$ 347,268	$ 377,157

7) DEBT

($ thousands)	**September 30, 2014**	**December 31, 2013**
Current:		
Senior notes	$ 96,937	$ 48,713
	$ 96,937	$ 48,713
Long term:		
Bank credit facility	$ 57,532	$ 214,394
Senior notes	938,745	762,191
	$ 996,277	$ 976,585
Total debt	$ 1,093,214	$ 1,025,298

On September 3, 2014 Enerplus closed a private placement of senior unsecured notes raising gross proceeds of US$200,000,000. The notes rank equally with the bank credit facility and other outstanding senior notes. The notes have a twelve year amortizing term and a ten year average life with a fixed coupon rate of 3.79%.

8) ASSET RETIREMENT OBLIGATION

Enerplus has estimated the present value of its asset retirement obligation to be $286.7 million at September 30, 2014 compared to $291.8 million at December 31, 2013, based on a total undiscounted liability of $707.2 million and $720.6 million, respectively. The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.92% at September 30, 2014 (December 31, 2013 – 5.96%).

($ thousands)	Nine months ended September 30, 2014	Year ended December 31, 2013
Balance, beginning of year	$ 291,761	$ 256,102
Change in estimates	(1,725)	44,217
Property acquisition and development activity	1,372	1,454
Dispositions	(3,990)	(8,362)
Settlements	(11,831)	(16,606)
Accretion Expense	11,161	14,956
Balance, end of period	$ 286,748	$ 291,761

9) OIL AND NATURAL GAS SALES

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2014	2013	2014	2013
Oil and natural gas sales	$ 456,215	$ 441,503	$ 1,455,790	$ 1,219,755
Royalties(1)	(77,883)	(76,112)	(254,793)	(199,659)
Oil and natural gas sales, net of royalties	$ 378,332	$ 365,391	$ 1,200,997	$ 1,020,096

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

10) GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2014	2013	2014	2013
General and administrative expense	$ 18,854	$ 20,031	$ 58,055	$ 63,514
Share-based compensation expense(1)	4,083	5,083	22,185	17,475
General and administrative expense	$ 22,937	$ 25,114	$ 80,240	$ 80,989

(1) Share-based compensation relates to the cash and equity-settled Long-term Incentive Plans and the Stock Option Plan. Refer to Note 14(c) for further discussion.

11) INTEREST EXPENSE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2014	2013	2014	2013
Realized:				
Interest on bank debt and senior notes	$ 14,924	$ 14,665	$ 45,552	$ 43,141
Unrealized:				
Cross currency interest rate swap (gain)/loss	–	273	580	1,093
Interest rate swap (gain)/loss	–	(42)	–	(478)
Amortization of debt issue costs	251	188	744	565
Interest expense	$ 15,175	$ 15,084	$ 46,876	$ 44,321

12) FOREIGN EXCHANGE

($ thousands)	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Realized:				
Foreign exchange (gain)/loss	$ (2,607)	$ 59	$ 14,069	$ 17,658
Unrealized:				
Translation of U.S. dollar debt and working capital (gain)/loss	33,863	(7,446)	35,798	9,092
Cross currency interest rate swap (gain)/loss	–	939	(16,130)	(19,043)
Foreign exchange derivative (gain)/loss	(758)	3,939	(8,995)	(3,680)
Foreign exchange (gain)/loss	$ 30,498	$ (2,509)	$ 24,742	$ 4,027

13) INCOME TAXES

($ thousands)	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Current tax expense/(recovery)				
Canada	$ (79)	$ (339)	$ (453)	$ (258)
U.S.	51	5,574	11,900	8,201
Current tax expense/(recovery)	(28)	5,235	11,447	7,943
Deferred tax expense/(recovery)				
Canada	$ 24,530	$ (17,561)	$ 19,212	$ (20,073)
U.S.	12,323	10,901	54,851	35,601
Deferred tax expense/(recovery)	$ 36,853	$ (6,660)	$ 74,063	$ 15,528
Income tax expense/(recovery)	$ 36,825	$ (1,425)	$ 85,510	$ 23,471

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.

14) SHAREHOLDERS' EQUITY

a) Share Capital

	Nine months ended September 30, 2014		Year ended December 31, 2013	
Authorized unlimited number of common shares **Issued:** (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	202,758	$ 3,061,839	198,684	$ 2,997,682
Issued for cash:				
Stock Option Plan	1,635	27,068	1,042	14,838
Non-cash:				
Stock Option Plan	–	4,783	–	3,108
Stock Dividend Plan	1,030	21,837	3,032	46,211
Balance, end of period	205,423	$ 3,115,527	202,758	$ 3,061,839

b) Dividends

($ thousands)	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Cash dividends	$ 51,088	$ 42,411	$ 143,750	$ 128,710
Stock dividends	4,350	11,994	21,837	33,489
Dividends to shareholders	$ 55,438	$ 54,405	$ 165,587	$ 162,199

c) Share-Based Compensation ("SBC")

The following table summarizes Enerplus' SBC expense, which is included in General and Administrative expense on the Consolidated Statements of Income/(Loss):

($ thousands)	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Cash:				
Long-term incentive plans expense/(recovery)	$ (5,174)	$ 4,869	$ 12,338	$ 14,074
Non-Cash:				
Long-term incentive plans expense	2,815	–	6,506	–
Stock option plan expense	598	1,686	3,401	7,164
Equity swap (gain)/loss	5,844	(1,472)	(60)	(3,763)
Share-based compensation expense	$ 4,083	$ 5,083	$ 22,185	$ 17,475

(i) Long-Term Incentive ("LTI") Plans

In 2014, the Performance Share Unit and Restricted Share Unit plans were amended such that grants under the plans are settled through the issuance of treasury shares. The amendment was effective beginning with our grant in March of 2014 and any prior grants will continue to be settled in cash.

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Director Share Unit ("DSU") activity for the nine months ended September 30, 2014:

For the nine months ended September 30, 2014 (thousands of units)	PSU	RSU	DSU	Total
Balance, beginning of year	650	821	99	1,570
Granted	550	832	47	1,429
Vested	–	(375)	–	(375)
Forfeited	(30)	(93)	–	(123)
Balance, end of period	1,170	1,185	146	2,501
End of period balances, by grant settlement type:				
Cash-settled units	630	409	146	1,185
Equity-settled units	540	776	–	1,316
Balance, end of period	1,170	1,185	146	2,501

Cash-settled LTI Plans

For the three months ended September 30, 2014 the Company recorded a recovery for cash SBC expense of $5.2 million and for the nine months ended September 30, 2014 recorded a charge of $12.3 million (September 30, 2013 – charges of $4.9 million and $14.1 million). For the three and nine months ended September 30, 2014, the Company made cash payments of $2.0 million and $13.8 million, respectively, related to its cash-settled plans (September 30, 2013 – $4.2 million and $11.1 million).

The following table summarizes the cumulative SBC expense recognized to-date, which has been recorded to Accounts Payable on the Consolidated Balance Sheets. Unrecognized amounts will be recorded to cash SBC expense over the remaining vesting terms.

At September 30, 2014 ($ thousands, except for years)	**PSU[1]**	**RSU**	**DSU**	**Total**
Cumulative recognized SBC expense	$ 19,412	$ 7,450	$ 3,380	$ 30,242
Unrecognized SBC expense	6,910	2,280	–	9,190
Intrinsic value	$ 26,322	$ 9,730	$ 3,380	$ 39,432
Weighted-average remaining contractual term (years)	0.8	0.8	–	

(1) Includes estimated performance multipliers.

Equity-settled LTI Plans

Equity-settled LTI awards are settled through the issuance of treasury shares and the related SBC expense is recorded as a non-cash amount on the Consolidated Statements of Income/(Loss), with an offset recorded to Paid-in Capital. On settlement, the amount previously recorded to Paid-in Capital is reclassified to Share Capital.

For the three and nine months ended September 30, 2014 the Company recorded non-cash SBC expense of $2.8 million and $6.5 million, respectively. No non-cash amounts were recognized for the three and nine months ended September 30, 2013 with respect to equity-settled grants.

The following table summarizes the cumulative SBC expense recognized to-date which is recorded to Paid-in Capital on the Consolidated Balance Sheets. Unrecognized amounts will be recorded to non-cash SBC expense over the remaining vesting terms.

At September 30, 2014 ($ thousands, except for years)	**PSU[1]**	**RSU**	**Total**
Cumulative recognized SBC expense	$ 1,592	$ 4,914	$ 6,506
Unrecognized SBC expense	6,252	8,561	14,813
	$ 7,844	$ 13,475	$ 21,319
Weighted-average remaining contractual term (years)	2.3	1.6	

(1) Includes estimated performance multipliers.

(ii) Stock Option Plan

The Company did not grant any stock options during the nine months ended September 30, 2014. Activity for the respective reporting periods is as follows:

	Nine months ended September 30, 2014	
	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding		
Beginning of year	13,414	$ 18.65
Granted	–	–
Exercised	(1,635)	16.56
Forfeited	(555)	19.49
Expired	–	–
Options outstanding, end of period	11,224	$ 18.91
Options exercisable at the end of period	6,247	$ 21.48

At September 30, 2014, 6,247,000 options were exercisable at a weighted average reduced exercise price of $21.48 with a weighted average remaining contractual term of 4.0 years, giving an intrinsic value of $17.4 million (September 30, 2013 – $2.6 million). The intrinsic value of options exercised during the three and nine months ended September 30, 2014 was $4.3 million and $12.4 million, respectively (September 30, 2013 – $2.2 million and $2.2 million).

At September 30, 2014 the unrecognized SBC expense related to non-vested options was $1.8 million (September 30, 2013 – $6.3 million). The expense is expected to be fully recognized over a weighted-average period of 0.9 years.

d) Paid-in Capital

The following table summarizes the paid-in capital activity for the nine months ended September 30, 2014 and the year ended December 31, 2013:

($ thousands)	Nine months ended September 30, 2014	Year ended December 31, 2013
Balance, beginning of year	$ 38,398	$ 32,293
Stock Option Plan – exercised	(4,783)	(3,108)
Share-based compensation – non-cash	9,907	9,213
Balance, end of period	$ 43,522	$ 38,398

e) Basic and Diluted Earnings Per Share

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

	Three months ended September 30,		Nine months ended September 30,	
(thousands, except per share amounts)	2014	2013	2014	2013
Net income/(loss)	$ 67,430	$ (3,720)	$ 147,424	$ 18,350
Weighted average shares outstanding – Basic	205,164	201,117	204,174	200,002
Dilutive impact of share-based compensation(1)	3,933	–	3,796	413
Weighted average shares outstanding – Diluted	209,097	201,117	207,970	200,415
Net income/(loss) per share				
Basic	0.33	(0.02)	0.72	0.09
Diluted	0.32	(0.02)	0.71	0.09

(1) For the three months ended September 30, 2013, the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At September 30, 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.

At September 30, 2014 senior notes included in long-term debt had a carrying value of $1,035.7 million and a fair value of $1,118.7 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 and nine months ended September 30, 2014 and 2013:

	Three months ended September 30,		Nine months ended September 30,		
Gain/(Loss) ($ thousands)	2014	2013	2014	2013	Income Statement Presentation
Interest Rate Swaps	$ –	$ 42	$ –	$ 478	Interest
Cross Currency Interest Rate Swap:					
Interest	–	(273)	(580)	(1,093)	Interest
Foreign Exchange	–	(939)	16,130	19,043	Foreign Exchange
Foreign Exchange Derivatives	758	(3,939)	8,995	3,680	Foreign Exchange
Electricity Swaps	22	(156)	204	1,314	Operating
Equity Swaps	(5,844)	1,472	60	3,763	General and Administrative
Commodity Derivative Instruments:					
Oil	82,874	(45,609)	48,671	(66,501)	Commodity derivative
Gas	10,879	452	8,270	4,255	instruments Gain/(loss)
Total	$ 88,689	$ (48,950)	$ 81,750	$ (35,061)	

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2014	2013	2014	2013
Change in fair value gain/(loss)	$ 93,753	$ (45,157)	$ 56,941	$ (62,246)
Net realized cash gain/(loss)	(2,485)	(10,517)	(42,339)	10,139
Commodity derivative instruments gain/(loss)	$ 91,268	$ (55,674)	$ 14,602	$ (52,107)

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

	September 30, 2014			December 31, 2013		
	Assets		Liabilities	Assets		Liabilities
($ thousands)	Current	Long-term	Current	Current	Long-term	Current
Cross Currency Interest Rate Swap	$ –	$ –	$ –	$ –	$ –	$ 15,548
Foreign Exchange Derivatives	758	23,937	–	564	15,135	–
Electricity Swaps	113	–	–	–	–	95
Equity Swaps	4,196	1,726	–	1,723	4,139	–
Commodity Derivative Instruments:						
Oil	28,251	5,588	–	4,138	–	18,970
Gas	7,588	1,037	–	2,773	–	2,418
Total	$ 40,906	$ 32,288	$ –	$ 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.

(ii) 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 October 22, 2014:

Crude Oil Instruments:

Instrument Type	bbls/day	US$/bbl(1)
Oct 1, 2014 – Oct 31, 2014		
WTI Swap	20,000	95.29
WCS Differential Swap	4,500	– 20.76
Brent – WTI Ratio Spread (% of Brent Price)	4,000	92.72%
Nov 1, 2014 – Dec 31, 2014		
WTI Swap	20,000	95.29
WCS Differential Swap	4,000	– 21.00
MSW Differential Swap	1,000	– 5.90
Brent – WTI Ratio Spread (% of Brent Price)	4,000	92.72%
Jan 1, 2015 – Jun 30, 2015		
WTI Swap	15,500	93.58
WCS Differential Swap	3,000	– 18.62
WTI Purchased Call	2,000	94.00
WTI Sold Put	2,000	63.00
Jul 1, 2015 – Dec 31, 2015		
WTI Swap	8,000	93.86
WCS Differential Swap	2,000	– 18.23
WTI Purchased Call	2,000	94.00
WTI Sold Put	2,000	63.00

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

Natural Gas Instruments:

Instrument Type	MMcf/day	CDN$/Mcf	US$/Mcf
Oct 1, 2014 – Dec 31, 2014			
AECO Swap	28.4	4.25	
Oct 1, 2014 – Dec 31, 2014			
NYMEX Swap	75.0		4.14
NYMEX Collar – Purchased Put	30.0		4.30
NYMEX Collar – Sold Call	30.0		5.08
NYMEX Purchased Call	25.0		4.17
NYMEX Sold Put	25.0		3.23
NYMEX Sold Call	25.0		5.00
Jan 1, 2015 – Mar 31, 2015			
NYMEX Swap	80.0		4.25
NYMEX Collar – Purchased Put	30.0		4.53
NYMEX Collar – Sold Call	30.0		5.53
NYMEX Purchased Call	5.0		4.29
NYMEX Sold Put	5.0		3.25
NYMEX Sold Call	5.0		5.00
Apr 1, 2015 – Jun 30, 2015			
NYMEX Swap	80.0		4.25
NYMEX Purchased Call	5.0		4.29
NYMEX Sold Put	5.0		3.25
NYMEX Sold Call	5.0		5.00
Jul 1, 2015 – Dec 31, 2015			
NYMEX Swap	60.0		4.16
NYMEX Purchased Call	5.0		4.29
NYMEX Sold Put	5.0		3.25
NYMEX Sold Call	5.0		5.00
Jan 1, 2016 – Dec 31, 2016			
NYMEX Swap	10.0		4.03

Electricity Instruments:

Instrument Type	MWh	CDN$/MWh
Oct 1, 2014 – Dec 31, 2014		
AESO Power Swap	16.0	53.33
Jan 1, 2015 – Dec 31, 2015		
AESO Power Swap	16.0	50.80
Jan 1, 2016 – Dec 31, 2016		
AESO Power Swap	6.0	50.25

Physical Contracts:

Instrument Type	MMcf/day	US$/Mcf
Oct 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 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 through the derivative instruments detailed below.

Foreign Exchange Derivatives:

During 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 October 22, 2014:

Instrument Type(1)	Monthly Notional Amount (US$ millions)	Floor	Ceiling	Conditional Ceiling(2)
Oct 1, 2014 – Dec 31, 2014	26.0	1.1064	1.1500	1.1212
Jan 1, 2015 – Dec 31, 2015	24.0	1.1088	1.1845	1.1263

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

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 September 30, 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 September 30, 2014, approximately 95% of Enerplus' debt was based on fixed interest rates and 5% was based on floating interest rates. The percentage of fixed interest rate debt has increased from prior periods due to the closing of US$200 million in additional senior notes at a fixed rate 3.79% rate of interest, with the proceeds being used to pay down floating interest rate bank debt. At September 30, 2014 Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its cash settled long-term incentive plans detailed in Note 14.

Enerplus has entered into various equity swaps maturing between 2014 and 2016 and has effectively fixed the future settlement cost on 950,000 shares at a weighted average price of $14.92 per share.

(iii) 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 September 30, 2014 approximately 70% of Enerplus' marketing receivables were with companies considered investment grade.

At September 30, 2014 approximately $4.7 million or 2% 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 September 30, 2014 was $2.9 million (December 31, 2013 – $2.8 million).

(iv) 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.

16) CONTINGENCIES AND COMMITMENTS

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.

The Company has entered into an additional transportation commitment for various pipelines in the Marcellus region. These contracts have varied terms, extend out as far as 2033, and comprise a total commitment of approximately US$54.3 million.

17) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2014	2013	2014	2013
Accounts receivable	$ 6,858	$ 17,522	$ (13,019)	$ 2,325
Other current assets	(5,754)	(1,755)	(5,210)	(2,944)
Accounts payable	(11,539)	9,917	(48,481)	11,991
	$ (10,435)	$ 25,684	$ (66,710)	$ 11,372

b) Other

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2014	2013	2014	2013
Income taxes paid/(received)	$ (254)	$ 3,487	$ 18,133	$ (1,403)
Interest paid	$ 4,138	$ 2,630	$ 32,826	$ 31,851

BOARD OF DIRECTORS

Elliott Pew[1][2]
Corporate Director
Boerne, Texas

David H. Barr[12]
Corporate Director
The Woodlands, Texas

Michael R. Culbert[3][9]
President & CEO
Progress Energy Canada Ltd.
Calgary, Alberta

Edwin V. Dodge[9][11]
Corporate Director
Vancouver, British Columbia

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

Hilary A. Foulkes[5][11]
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

Douglas R. Martin
Corporate Director
Calgary, Alberta

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

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

Sheldon B. Steeves[5][8]
Corporate Director
Calgary, Alberta

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

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

Jodine J. Jenson Labrie
Vice President, Finance

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

H. Gordon Love
Vice President, Technical & Operations Services

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

Edward L. McLaughlin
President, U.S. Operations

Lisa M. Ower
Vice President, Human Resources

Christopher M. Stephens
Vice President, Canadian Assets

P. Scott Walsh
Vice President, Information & Corporate Services

Kenneth W. Young
Vice President, Land

Michael R. Politeski
Treasurer & Corporate Controller

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, Suite 2200
Denver, Colorado 80202

Telephone: 720.279.5500
Fax: 720.279.5550

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 diversified asset base of high-quality, low-decline oil and gas assets complemented by growth assets in resource plays with superior economics. We are focused on creating value for our investors through the successful development of our properties and the disciplined management of our balance sheet. Through our activities, we strive to provide investors with a competitive return comprised of both growth and income.

enerPLUS

www.enerplus.com
Toll Free 1.800.319.6462
investorrelations@enerplus.com

The Dome Tower
3000, 333 – 7th Avenue SW
Calgary, Alberta T2P 2Z1

ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE