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

The following discussion and analysis of financial results is dated August 6, 2015 and is to be read in conjunction with:

- the unaudited interim consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three and six months ended June 30, 2015 and 2014 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2014 and 2013 and for the years ended December 31, 2014, 2013 and 2012; and
- our MD&A for the year ended December 31, 2014 (the "Annual MD&A").

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. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" below for further information.

## BASIS OF PRESENTATION

The Interim Financial Statements and notes have been prepared in accordance with U.S. GAAP including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified and all other references relate to the notes included in the Interim Financial Statements.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. 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 interest unless otherwise stated. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities and may not be comparable to information produced by other entities.

In accordance with U.S. GAAP, oil and gas sales are presented net of royalties in our Interim Financial Statements. Under International Financial Reporting Standards, 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 less royalties, production taxes, cash operating costs and transportation.

| Calculation of Netback ($ millions) | Three months ended June 30, 2015 | Three months ended June 30, 2014 | Six months ended June 30, 2015 | Six months ended June 30, 2014 |
|---|---|---|---|---|
| Oil and natural gas sales | $ 298.4 | $ 504.5 | $ 542.5 | $ 999.6 |
| Less: | | | | |
| Royalties | (46.7) | (89.6) | (85.8) | (176.9) |
| Production taxes | (14.2) | (20.0) | (25.0) | (39.8) |
| Cash operating costs(1) | (79.3) | (86.2) | (166.2) | (166.1) |
| Transportation | (28.0) | (22.6) | (54.5) | (45.0) |
| Netback before hedging | $ 130.2 | $ 286.1 | $ 211.0 | $ 571.8 |
| Cash gains/(losses) on derivative instruments | 73.1 | (24.5) | 159.9 | (39.9) |
| Netback after hedging | $ 203.3 | $ 261.6 | $ 370.9 | $ 531.9 |

(1) Operating costs adjusted to exclude non-cash gains on fixed price electricity swaps of $2.6 million and $1.7 million in the three and six months ended June 30, 2015 and $0.2 million in both the three and six months ended June 30, 2014.

**"Funds Flow"** is used by Enerplus and useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. Funds flow is calculated as net cash provided by operating activities before asset retirement obligation expenditures and changes in non-cash operating working capital.

| Reconciliation of Cash Flow from Operating Activities to Funds Flow ($ millions) | Three months ended June 30, 2015 | Three months ended June 30, 2014 | Six months ended June 30, 2015 | Six months ended June 30, 2014 |
|---|---|---|---|---|
| Cash flow from operating activities | $ 135.0 | $ 228.5 | $ 266.2 | $ 368.9 |
| Asset retirement obligation expenditures | 2.6 | 4.2 | 6.5 | 8.5 |
| Changes in non-cash operating working capital | 22.8 | (19.5) | (3.1) | 56.3 |
| Funds Flow | $ 160.4 | $ 213.2 | $ 269.6 | $ 433.7 |

**"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. This measure is not equivalent to Debt to Earnings before Interest, Taxes, Depreciation and Amortization and other non-cash charges ("EBITDA") and is not a debt covenant.

**"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 cash dividends plus capital and office expenditures divided by funds flow.

| Calculation of Adjusted Payout Ratio ($ millions) | Three months ended June 30, 2015 | Three months ended June 30, 2014 | Six months ended June 30, 2015 | Six months ended June 30, 2014 |
|---|---|---|---|---|
| Cash dividends(1) | $ 30.9 | $ 50.5 | $ 78.3 | $ 92.7 |
| Capital and office expenditures | 149.4 | 205.6 | 317.3 | 423.8 |
| | $ 180.3 | $ 256.1 | $ 395.6 | $ 516.5 |
| Funds flow | 160.4 | 213.2 | 269.6 | 433.7 |
| Adjusted payout ratio (%) | 112% | 120% | 147% | 119% |

(1) Cash dividends exclude stock dividend plan proceeds in 2014.

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections of this 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. Such measures include "Senior Debt to EBITDA", "Total Debt to EBITDA", "Total Debt to Capitalization", "maximum debt to consolidated present value of total proven reserves" and "EBITDA to Interest" and are used to determine the Company's compliance with financial covenants under its bank credit facility and outstanding senior notes. Calculation of such terms is described under the "Liquidity and Capital Resources" section of this MD&A.

## OVERVIEW

Our strong operational performance continued in the second quarter as we delivered production growth and met or exceeded all our guidance targets. As a result, we are increasing our 2015 production guidance and lowering our operating cost and general and administrative ("G&A") expense guidance by $0.65/BOE, combined. All other guidance targets are maintained.

Average daily production for the second quarter was 107,429 BOE/day, exceeding our annual average production guidance range of 97,000-103,000 BOE/day. Production increased approximately 6,600 BOE/day or 7% from the first quarter of 2015. The majority of the production growth was driven by our ongoing development in Fort Berthold, North Dakota, where production increased 26% or approximately 5,600 BOE/day compared to the first quarter. Natural gas production increased 6% from the prior quarter due to the ongoing development of our Canadian deep gas properties and well outperformance in the Marcellus. Based on our continued operational success, we are increasing our production guidance range to 100,000-104,000 BOE/day and expect approximately 44,000-46,000 bbls/day of crude oil and natural gas liquids.

We maintained a disciplined capital program with spending of $148.0 million in our core areas during the quarter and are on track to meet our annual capital spending guidance of $540.0 million.

Both operating costs and G&A expenses came in below guidance, at $76.7 million or $7.85/BOE and $19.9 million or $2.03/BOE, respectively. As a result of our continued focus on cost control and increased production target, we are decreasing our operating cost guidance to $9.25/BOE from $9.75/BOE and our G&A expense guidance to $2.25/BOE from $2.40/BOE, representing a combined decrease of $0.65/BOE.

Funds flow increased by 47% to $160.4 million from $109.2 million in the first quarter as a result of production growth and higher oil prices, along with the impact of one-time expenses experienced in the first quarter. Compared to the same period in 2014, funds flow decreased by approximately $52.8 million or 25% as oil and natural gas sales reflected the significant decline in commodity prices. Our hedging program provided additional revenue, generating gains of $73.1 million in the quarter compared to losses of $24.5 million in the same period of 2014.

Under U.S. GAAP, we recorded a net loss of $312.5 million for the quarter compared to net income of $40.0 million in the second quarter of 2014. The continued decline in the twelve month trailing average commodity price resulted in an asset impairment of $497.2 million in the quarter. Year to date, we have recorded cumulative asset impairments of $764.9 million. We expect the twelve month trailing prices used to calculate impairment charges in accordance with U.S. GAAP to decline further, which may lead to additional write-downs of our oil and natural gas properties in the second half of 2015.

Despite a decline in commodity prices during the first half of 2015 we remain in a strong financial position. At June 30, 2015 we were approximately 8% drawn on our $1.0 billion credit facility and had a conservative debt to funds flow ratio of 1.6x and senior debt to EBITDA ratio of 1.5x. After a US$10.8 million senior note repayment due in the fourth quarter of 2015 we will have no term debt principal repayments due until June of 2017. We have added significantly to our hedging program during the quarter and continue to expect our risk management program to protect our balance sheet and a portion of our funds flow in the second half of 2015 and into 2016.

## RESULTS OF OPERATIONS

### Production

Production for the second quarter totaled 107,429 BOE/day, exceeding our guidance range of 97,000-103,000 BOE/day and increasing 7% compared to 100,855 BOE/day in the first quarter of 2015. This increase was driven primarily by growth in our Fort Berthold production, which increased 26% or 5,600 BOE/day compared to the prior quarter. We brought on 9.2 net wells in Fort Berthold during the quarter compared to 3.6 net wells in the first quarter. Based on our decision to accelerate the completion of eight additional wells during the second half of 2015 we expect modest production growth in the region. Natural gas production increased by 6% from the prior quarter due to our ongoing development program in the Canadian Deep Basin as well as continued well outperformance in the Marcellus.

Production in the second quarter of 2015 increased by 3% from 103,987 BOE/day in the same period of 2014 primarily due to an increase in Fort Berthold crude oil production. Natural gas production remained relatively flat compared to the second quarter of 2014, with growth in our Marcellus and Canadian Deep Basin production offset by the divestment of non-core Canadian natural gas properties in the second half of 2014.

Our production mix was unchanged from the previous quarter with crude oil and natural gas liquids accounting for 43% of our total average daily production.

Average daily production volumes for the three and six months ended June 30, 2015 and 2014 are outlined below:

| | Three months ended June 30, | | | Six months ended June 30, | | |
|---|---|---|---|---|---|---|
| **Average Daily Production Volumes** | **2015** | **2014** | **% Change** | **2015** | **2014** | **% Change** |
| Crude oil (bbls/day) | 41,122 | 39,863 | 3% | 40,243 | 38,817 | 4% |
| Natural gas liquids (bbls/day) | 5,145 | 3,636 | 42% | 4,444 | 3,450 | 29% |
| Natural gas (Mcf/day) | 366,971 | 362,929 | 1% | 356,836 | 354,906 | 1% |
| Total daily sales (BOE/day) | 107,429 | 103,987 | 3% | 104,160 | 101,418 | 3% |

As a result of continued outperformance we are revising our average annual production guidance upwards to 100,000-104,000 BOE/day from our guidance of 97,000-103,000 BOE/day provided in June. We expect annual production to include 44,000-46,000 bbls/day of crude oil and natural gas liquids.

## Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, funds flow and financial condition. The following table compares quarterly average prices from the second quarter of 2015 to the second quarter of 2014:

| | Six months ended June 30, | | | | | | |
|---|---|---|---|---|---|---|---|
| **Pricing** (average for the period) | **2015** | **2014** | **Q2 2015** | **Q1 2015** | **Q4 2014** | **Q3 2014** | **Q2 2014** |
| **Benchmarks** | | | | | | | |
| WTI crude oil (US$/bbl) | $ 53.29 | $ 100.84 | $ 57.94 | $ 48.64 | $ 73.15 | $ 97.17 | $ 102.99 |
| AECO natural gas – monthly index (CDN$/Mcf) | 2.81 | 4.72 | 2.67 | 2.95 | 4.01 | 4.22 | 4.68 |
| AECO natural gas – daily index (CDN$/Mcf) | 2.70 | 5.20 | 2.64 | 2.75 | 3.60 | 4.02 | 4.69 |
| NYMEX natural gas – last day (US$/Mcf) | 2.81 | 4.80 | 2.64 | 2.98 | 4.00 | 4.06 | 4.67 |
| US/CDN exchange rate | 1.24 | 1.10 | 1.23 | 1.24 | 1.14 | 1.09 | 1.09 |
| **Enerplus Selling Price**[1] | | | | | | | |
| Crude oil (CDN$/bbl) | $ 51.35 | $ 94.80 | $ 58.26 | $ 44.04 | $ 69.17 | $ 88.28 | $ 96.46 |
| Natural gas liquids (CDN$/bbl) | 21.55 | 59.37 | 20.88 | 22.48 | 42.34 | 46.76 | 51.80 |
| Natural gas (CDN$/Mcf) | 2.32 | 4.60 | 2.09 | 2.58 | 3.25 | 3.36 | 4.15 |
| **Average differentials** | | | | | | | |
| MSW Edmonton – WTI (US$/bbl) | $ (4.93) | $ (7.19) | $ (3.06) | $ (6.80) | $ (6.36) | $ (7.93) | $ (6.13) |
| WCS Hardisty – WTI (US$/bbl) | (13.16) | (21.59) | (11.59) | (14.73) | (14.24) | (20.18) | (20.04) |
| Brent Futures (ICE) – WTI (US$/bbl) | 6.10 | 7.97 | 5.63 | 6.58 | 3.85 | 6.26 | 6.75 |
| AECO monthly – NYMEX (US$/Mcf) | (0.54) | (0.50) | (0.47) | (0.60) | (0.47) | (0.18) | (0.38) |
| **Enerplus realized differentials**[1] | | | | | | | |
| Canada crude oil – WTI (US$/bbl) | $ (14.13) | $ (18.36) | $ (12.50) | $ (15.22) | $ (12.17) | $ (20.51) | $ (16.77) |
| Canada natural gas – NYMEX (US$/Mcf) | (0.46) | (0.25) | (0.46) | (0.46) | (0.62) | (0.29) | (0.46) |
| Bakken crude oil – WTI (US$/bbl) | (10.05) | (11.29) | (9.30) | (11.65) | (12.15) | (12.81) | (12.81) |
| Marcellus natural gas – NYMEX (US$/Mcf) | (1.35) | (1.19) | (1.39) | (1.32) | (1.62) | (1.70) | (1.48) |

(1) Before transportation costs, royalties and commodity derivative instruments.

### Crude Oil and Natural Gas Liquids

WTI crude oil prices increased by 19% versus the previous quarter to average US$57.94/bbl during the second quarter of 2015. Although crude oil inventories in the U.S. reached record levels of 491 million barrels in April, strong seasonal demand for gasoline and early indications of slowing crude oil production growth in the U.S. resulted in inventory levels falling and WTI prices trading over US$60/bbl. However, increasing concerns over the Chinese economy and its potential negative impact on crude oil demand growth, the nuclear agreement with Iran that will eventually allow increased Iranian production to return to the market and the ongoing debt crisis in Greece all contributed to the decline of WTI to under US$50/bbl by mid-July.

The strength in WTI prices during the second quarter combined with improved realized crude oil differentials resulted in a 32% improvement in selling price for our crude oil compared to the previous quarter. Crude oil differentials in Canada strengthened considerably during the second quarter, due largely to scheduled oil sands maintenance and other unplanned outages from forest fires in Northern Alberta reducing production. As a result, WCS differentials to WTI narrowed by US$3.14/bbl to average US$11.59/bbl below WTI and light sweet crude oil differentials in Canada narrowed by US$3.74/bbl to average US$3.06/bbl below WTI. The strength in light sweet differentials helped support our Bakken differentials as well, which narrowed by US$2.35/bbl quarter over quarter to average US$9.30/bbl below WTI during the second quarter. We expect both heavy and light oil differentials in Canada and the U.S. to widen for the rest of the year relative to the second quarter, as production is stabilizing in the affected regions.

The decline in crude oil prices over the past twelve months and the level of natural gas liquids production across the continent continues to depress North American natural gas liquids prices, specifically propane. As propane production and inventories in Canada and the U.S. grow, it has resulted in negative benchmark prices for propane during May and June. However, stronger WTI prices during the quarter helped stabilize market prices for butanes and condensate, partially offsetting the weakness in propane prices. Our realized price for our natural gas liquids production fell by 7% quarter over quarter to average $20.88/bbl.

### Natural Gas

Both AECO monthly index and NYMEX natural gas prices fell by 9% and 11%, respectively, versus the previous quarter due to continued high production and increased storage levels across the continent. U.S. dry gas production in June was approximately 3.0 Bcf/day higher than last year while U.S. storage levels ended the quarter in line with the five year average. Although production remains high, demand for natural gas fired power generation increased relative to previous years as natural gas prices were low enough to incentivize generators to switch from coal to natural gas as a fuel for power generation. This increased power demand, combined with higher than expected exports from the U.S. to Mexico, provided some price support by offsetting the continued strong North American production. However, even with the extra demand and normal weather, the strong production may push storage inventories to test the upper end of capacity levels by the end of October.

In Western Canada, there were ongoing service interruptions and restrictions in certain areas of the NOVA Gas Transmission Ltd. ("NGTL") pipeline system as TransCanada was required by the National Energy Board to carry out thorough safety inspections of smaller diameter pipelines. These restrictions, combined with other unplanned maintenance issues across the system, have caused many producers in Western Canada to curtail natural gas production. Overall, we have been able to limit the impact on Enerplus through holding firm transportation in our key areas and actively managing transportation shortfalls at affected locations. We had on average roughly 5 MMcfe/day of natural gas production temporarily curtailed during the quarter due to these restrictions. We anticipate the curtailment of transportation services to ease somewhat before the end of the year, however, the issue may persist into 2016 as further NGTL safety inspections are required.

Our overall realized sales price for natural gas fell by 19% compared to the previous quarter to average $2.09/Mcf. This is in line with the combination of weaker NYMEX pricing and continued weakness in the Marcellus producing region. While the average of spot market prices in Northeast Pennsylvania at the Transco Leidy and TGP Zone 4 Marcellus were roughly unchanged from the first quarter, outside of the northeast Pennsylvania producing region prices at Dominion South Point fell by 24% to average US$1.40/Mcf in the quarter. With approximately 37% of our Marcellus production tied to markets outside the northeast Pennsylvania producing region that all realized wider differentials to NYMEX versus the previous quarter, our overall realized discount to NYMEX for our Marcellus production widened by 5% or US$0.07/Mcf versus the first quarter to average US$1.39/Mcf.

### Foreign Exchange

The Canadian dollar strengthened during the second quarter, increasing a modest 2% as a result of higher crude oil prices. Subsequent to the quarter, we saw the Canadian dollar fall to a six year low USD/CDN exchange rate of 1.30 following the Bank of Canada's decision to cut interest rates by 25 basis points and lower their forecasted economic growth for 2015. The majority of our oil and natural gas sales are based on U.S. dollar denominated indices and therefore a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. Because we report in Canadian dollars, the weaker Canadian dollar also increases our U.S. dollar denominated operating costs, capital spending and the principal and interest on our U.S. dollar denominated senior notes.

**Price Risk Management**

We have a price risk management program that considers our overall financial position, the economics of our capital program and potential acquisitions. We continued to add to our commodity hedge position in both 2015 and 2016 as a result of the modest improvement in crude oil prices during the quarter along with our decision to accelerate the completions of eight additional North Dakota wells. For the second half of 2015 we have an average of 11,250 bbls/day of crude oil (approximately 35% of our expected crude oil production, net of royalties) hedged at an average floor price of US$84.58/bbl through a combination of swaps and three-way collar structures. In 2016 we have an average of 11,000 bbls/day of crude oil (approximately 34% of our expected crude oil production, net of royalties) hedged at an average floor price of US$64.35/bbl through a combination of swaps and three-way collar structures.

We continued to add to our NYMEX gas hedging program for 2015 and began hedging our 2016 gas production during the quarter. In the second half of 2015 we are swapped on an average of 128,370 Mcf/day (approximately 47% of our forecasted natural gas production, net of royalties) at an average price of US$3.82/Mcf. In 2016 we have 25,000 Mcf/day (approximately 9% of our forecasted natural gas production, net of royalties) hedged through three-way collars with an average floor price of US$3.00/Mcf.

The following is a summary of our financial contracts in place at July 22, 2015 expressed as a percentage of our anticipated net production volumes:

| | WTI Crude Oil (US$/bbl)(1) | | | | NYMEX Natural Gas (US$/Mcf)(1) | | | |
|---|---|---|---|---|---|---|---|---|
| | Jul 1, 2015 – Sept 30, 2015 | Oct 1, 2015 – Dec 31, 2015 | Jan 1, 2016 – Jun 30, 2016 | Jul 1, 2016 – Dec 31, 2016 | Jul 1, 2015 – Sept 30, 2015 | Oct 1, 2015 – Oct 31, 2015 | Nov 1, 2015 – Dec 31, 2015 | Jan 1, 2016 – Dec 31, 2016 |
| **Downside Protection – Swaps** | | | | | | | | |
| Sold Swaps | $ 93.86 | $ 82.10 | $ 64.28 | – | $ 3.73 | $ 3.85 | $ 4.04 | – |
| % | 25% | 39% | 9% | – | 57% | 42% | 35% | – |
| **Downside Protection – Collars** | | | | | | | | |
| Sold Puts | – | $ 48.00 | $ 50.13 | $ 49.34 | – | – | – | $ 2.50 |
| % | – | 6% | 25% | 34% | – | – | – | 9% |
| Purchased Puts | – | $ 63.00 | $ 64.38 | $ 64.35 | – | – | – | $ 3.00 |
| % | – | 6% | 25% | 34% | – | – | – | 9% |
| Sold Calls | – | $ 70.00 | $ 79.38 | $ 80.09 | – | – | – | $ 3.75 |
| % | – | 6% | 25% | 34% | – | – | – | 9% |
| **Upside Participation Collars** | | | | | | | | |
| Sold Puts | $ 62.23 | $ 62.23 | – | – | $ 3.25 | $ 3.25 | $ 3.25 | – |
| % | 13% | 13% | – | – | 2% | 2% | 2% | – |
| Purchased Calls | $ 93.00 | $ 93.00 | – | – | $ 4.29 | $ 4.29 | $ 4.29 | – |
| % | 13% | 13% | – | – | 2% | 2% | 2% | – |
| Sold Calls | – | – | – | – | $ 5.00 | $ 5.00 | $ 5.00 | – |
| % | – | – | – | – | 2% | 2% | 2% | – |

(1) Based on weighted average price (before premiums), assumed average annual production of 100,000 – 104,000 BOE/day for 2015 and 2016, less royalties and production taxes of 21.0% in aggregate.

We have also entered into WCS and MSW differential swap positions to manage our exposure to Canadian crude oil differentials. At July 22, 2015, we have 4,000 bbls/day of WCS swapped at US$(16.61)/bbl and 1,000 bbls/day of MSW swapped at US$(3.50)/bbl in the second half of 2015 and 2,000 bbls/day of WCS swapped at US$(14.50)/bbl in 2016.

We have physically hedged a portion of our exposure to AECO differentials versus NYMEX prices through to October 2019. These basis transactions are intended to protect against weakening natural gas prices in Alberta as increased production from the Marcellus is expected to flow into Ontario and the U.S. Midwest over the coming years. There is also a risk of weaker AECO prices as a result of continued growth in natural gas production in advance of potential Canadian west coast liquefied natural gas exports.

The following table provides a summary of the physical AECO-NYMEX basis contracts we have in place at July 22, 2015:

| | MMcf/day | US$/Mcf |
|---|---|---|
| Jul 1, 2015 – Oct 31, 2015<br>AECO-NYMEX Basis | 60.0 | $ (0.65) |
| Nov 1, 2015 – Oct 31, 2016<br>AECO-NYMEX Basis | 60.0 | $ (0.67) |
| Nov 1, 2016 – Oct 31, 2017<br>AECO-NYMEX Basis | 80.0 | $ (0.65) |
| Nov 1, 2017 – Oct 31, 2018<br>AECO-NYMEX Basis | 80.0 | $ (0.65) |
| Nov 1, 2018 – Oct 31, 2019<br>AECO-NYMEX Basis | 80.0 | $ (0.64) |

In 2014 we entered into foreign exchange collars on US$24 million per month to hedge a floor exchange rate on a portion of our U.S. dollar denominated oil and natural gas sales with upside participation in the event the Canadian dollar weakened. During the second quarter of 2015 we entered into U.S. dollar forward exchange contracts on US$6 million per month at an exchange rate of USD/CDN 1.20 to partially mitigate our losses on these collars. As of July 22, 2015, we effectively have US$18 million per month hedged for 2015 at an average USD/CDN floor of 1.1088, a ceiling of 1.1845 and a conditional ceiling of 1.1263. Under these contracts, if the monthly foreign exchange rate settles above the ceiling rate the conditional celling is used to determine the settlement amount.

## ACCOUNTING FOR PRICE RISK MANAGEMENT

| **Commodity Risk Management Gains/(Losses)**<br>($ millions) | Three months ended June 30, 2015 | Three months ended June 30, 2014 | Six months ended June 30, 2015 | Six months ended June 30, 2014 |
|---|---|---|---|---|
| Cash gains/(losses): | | | | |
| Crude oil | $ 56.7 | $ (21.2) | $ 127.2 | $ (32.0) |
| Natural gas | 16.4 | (3.3) | 32.7 | (7.9) |
| Total cash gains/(losses) | $ 73.1 | $ (24.5) | $ 159.9 | $ (39.9) |
| Non-cash gains/(losses): | | | | |
| Change in fair value – crude oil | $ (71.1) | $ (24.8) | $ (107.1) | $ (34.2) |
| Change in fair value – natural gas | (21.8) | 5.3 | (22.2) | (2.6) |
| Total non-cash gains/(losses) | $ (92.9) | $ (19.5) | $ (129.3) | $ (36.8) |
| Total gains/(losses) | $ (19.8) | $ (44.0) | $ 30.6 | $ (76.7) |

| (Per BOE) | Three months ended June 30, 2015 | Three months ended June 30, 2014 | Six months ended June 30, 2015 | Six months ended June 30, 2014 |
|---|---|---|---|---|
| Total cash gains/(losses) | $ 7.47 | $ (2.60) | $ 8.48 | $ (2.17) |
| Total non-cash gains/(losses) | (9.49) | (2.06) | (6.85) | (2.01) |
| Total gains/(losses) | $ (2.02) | $ (4.66) | $ 1.63 | $ (4.18) |

During the second quarter of 2015 we realized cash gains of $56.7 million on our crude oil contracts and $16.4 million on our natural gas contracts. In comparison, during the second quarter of 2014 we realized cash losses of $21.2 million on our crude oil contracts and $3.3 million on our natural gas contracts. The cash gains in 2015 were due to contracts which provided floor protection above market prices, while cash losses in 2014 were a result of prices rising above our fixed price swap positions.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At the end of the second quarter of 2015 the fair value of our crude oil and natural gas contracts represented net gain positions of $60.1 million and $27.1 million, respectively. For the three and six months ended June 30, 2015 the change in the fair value of our crude oil contracts represented losses of $71.1 million and $107.1 million, respectively, and our natural gas contracts represented losses of $21.8 million and $22.2 million, respectively.

During the three and six months ended June 30, 2015 we recorded total cash losses on our foreign exchange collars of $7.1 million and $15.7 million, respectively. At June 30, 2015 the fair value of foreign exchange derivatives was a net loss of $12.5 million. See Note 15 for further information.

### Revenues

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions) | 2015 | 2014 | 2015 | 2014 |
| Oil and natural gas | $ 298.4 | $ 504.5 | $ 542.5 | $ 999.6 |
| Royalties | (46.7) | (89.6) | (85.8) | (176.9) |
| Oil and natural gas sales, net of royalties | $ 251.7 | $ 414.9 | $ 456.7 | $ 822.7 |

Oil and natural gas revenues for the three and six months ended June 30, 2015 were $298.4 million and $542.5 million, respectively, compared to $504.5 million and $999.6 million for the same periods in 2014. The decrease in revenue was driven by the weak commodity price environment, which saw benchmark prices decline between 40% and 48% in the first half of 2015 compared to the same period in 2014.

### Royalties and Production Taxes

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions, except per BOE amounts) | 2015 | 2014 | 2015 | 2014 |
| Royalties | $ 46.7 | $ 89.6 | $ 85.8 | $ 176.9 |
| Per BOE | $ 4.78 | $ 9.47 | $ 4.55 | $ 9.64 |
| Production taxes | $ 14.2 | $ 20.0 | $ 25.0 | $ 39.8 |
| Per BOE | $ 1.45 | $ 2.11 | $ 1.33 | $ 2.17 |
| Royalties and production taxes | $ 60.9 | $ 109.6 | $ 110.8 | $ 216.7 |
| Per BOE | $ 6.23 | $ 11.58 | $ 5.88 | $ 11.81 |
| Royalties and production taxes (% of oil and natural gas sales, before transportation) | 20% | 22% | 20% | 22% |

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. During the three and six months ended June 30, 2015 royalties and production taxes decreased to $60.9 million and $110.8 million, respectively, from $109.6 million and $216.7 million for the same periods in 2014, primarily due to lower realized prices. Royalties and production taxes averaged 20% of oil and natural gas sales before transportation in the first half of 2015 compared to 22% for the same period in 2014.

We continue to expect an average royalty and production tax rate of 21% in 2015.

### Operating Expenses

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions, except per BOE amounts) | 2015 | 2014 | 2015 | 2014 |
| Operating expenses | $ 76.7 | $ 86.0 | $ 164.5 | $ 165.9 |
| Per BOE | $ 7.85 | $ 9.09 | $ 8.72 | $ 9.03 |

As of January 1, 2015 we have reclassified Marcellus gathering costs from operating expenses to transportation costs. These charges relate to pipeline costs paid to third parties to transport saleable natural gas from the lease to downstream points of sale. This is a presentation change with no impact on our netback, funds flow or net income. All comparative periods have been presented to conform with the current period presentation.

Operating expenses continued to trend lower as a result of our cost saving initiatives. For the three and six months ended June 30, 2015 operating expenses were $76.7 million or $7.85/BOE and $164.5 million or $8.72/BOE, respectively, compared to $86.0 million or $9.09/BOE and $165.9 million or $9.03/BOE for the same periods in 2014. The decrease in operating costs during 2015 compared to 2014 was primarily due to realized cost savings in repairs and maintenance and well servicing, which were offset somewhat by the impact of a weaker Canadian dollar on our U.S. dollar denominated operating costs.

Based on our cost savings realized to date and our increased production guidance we are reducing our 2015 guidance for operating expenses to $9.25/BOE from $9.75/BOE. Although year to date operating costs are below our revised guidance, we anticipate an increase in operating costs during the second half of 2015 as a result of the seasonality of some spend and scheduled facility turnarounds.

### Transportation Costs

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions, except per BOE amounts) | 2015 | 2014 | 2015 | 2014 |
| Transportation costs | $ 28.0 | $ 22.6 | $ 54.5 | $ 45.0 |
| Per BOE | $ 2.87 | $ 2.39 | $ 2.89 | $ 2.45 |

As discussed previously in operating expenses, we have reclassified Marcellus gathering costs from operating expenses to transportation costs. This is a presentation change with no impact on our netback, funds flow or net income. All comparative periods have been presented to conform with the current period presentation.

For the three and six months ended June 30, 2015 transportation costs were $28.0 million or $2.87/BOE and $54.5 million or $2.89/BOE, respectively, compared to $22.6 million or $2.39/BOE and $45.0 million or $2.45/BOE for the same periods in 2014. The increase in transportation costs was due to higher U.S. production and the impact of a weakening Canadian dollar on our U.S. dollar denominated costs.

We are maintaining our transportation cost guidance of $3.00/BOE.

### Netbacks

The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A. Certain prior period amounts have been reclassified to conform with current period presentations.

| | Three months ended June 30, 2015 | | |
|---|---|---|---|
| **Netbacks by Property Type** | **Crude Oil** | **Natural Gas** | **Total** |
| Average Daily Production | 49,058 BOE/day | 350,226 Mcfe/day | 107,429 BOE/day |
| Netback[(1)] $ per BOE or Mcfe | (per BOE) | (per Mcfe) | (Per BOE) |
| Oil and natural gas sales | $ 52.17 | $ 2.06 | $ 30.53 |
| Royalties and production taxes | (12.15) | (0.21) | (6.23) |
| Cash operating costs | (11.27) | (0.91) | (8.12) |
| Transportation | (1.68) | (0.64) | (2.87) |
| Netback before hedging | $ 27.07 | $ 0.30 | $ 13.31 |
| Cash gains/(losses) | 12.69 | 0.52 | 7.47 |
| Netback after hedging | $ 39.76 | $ 0.82 | $ 20.78 |
| Netback before hedging ($ millions) | $ 121.0 | $ 9.2 | $ 130.2 |
| Netback after hedging ($ millions) | $ 177.6 | $ 25.7 | $ 203.3 |

| Netbacks by Property Type | Three months ended June 30, 2014 Crude Oil | | Natural Gas | | Total |
|---|---|---|---|---|---|
| Average Daily Production | 44,681 BOE/day | | 355,836 Mcfe/day | | 103,987 BOE/day |
| Netback[1] $ per BOE or Mcfe | (per BOE) | | (per Mcfe) | | (Per BOE) |
| Oil and natural gas sales | $ 88.42 | | $ 4.49 | | $ 53.32 |
| Royalties and production taxes | (21.06) | | (0.74) | | (11.58) |
| Cash operating costs | (12.96) | | (1.04) | | (9.12) |
| Transportation | (1.69) | | (0.49) | | (2.39) |
| Netback before hedging | $ 52.71 | | $ 2.22 | | $ 30.23 |
| Cash gains/(losses) | (5.23) | | (0.10) | | (2.60) |
| Netback after hedging | $ 47.48 | | $ 2.12 | | $ 27.63 |
| Netback before hedging ($ millions) | $ 214.4 | | $ 71.7 | | $ 286.1 |
| Netback after hedging ($ millions) | $ 193.1 | | $ 68.5 | | $ 261.6 |

| Netbacks by Property Type | Six months ended June 30, 2015 Crude Oil | Natural Gas | Total |
|---|---|---|---|
| Average Daily Production | 46,916 BOE/day | 343,464 Mcfe/day | 104,160 BOE/day |
| Netback[1] $ per BOE or Mcfe | (per BOE) | (per Mcfe) | (Per BOE) |
| Oil and natural gas sales | $ 46.98 | $ 2.31 | $ 28.78 |
| Royalties and production taxes | (10.99) | (0.28) | (5.88) |
| Cash operating costs | (12.31) | (0.99) | (8.81) |
| Transportation | (1.82) | (0.63) | (2.89) |
| Netback before hedging | $ 21.86 | $ 0.41 | $ 11.20 |
| Cash gains/(losses) | 14.98 | 0.53 | 8.48 |
| Netback after hedging | $ 36.84 | $ 0.94 | $ 19.68 |
| Netback before hedging ($ millions) | $ 185.6 | $ 25.4 | $ 211.0 |
| Netback after hedging ($ millions) | $ 312.9 | $ 58.0 | $ 370.9 |

| Netbacks by Property Type | Six months ended June 30, 2014 Crude Oil | Natural Gas | Total |
|---|---|---|---|
| Average Daily Production | 43,519 BOE/day | 347,394 Mcfe/day | 101,418 BOE/day |
| Netback[1] $ per BOE or Mcfe | (per BOE) | (per Mcfe) | (Per BOE) |
| Oil and natural gas sales | $ 87.47 | $ 4.93 | $ 54.45 |
| Royalties and production taxes | (21.19) | (0.79) | (11.81) |
| Cash operating costs | (12.69) | (1.05) | (9.04) |
| Transportation | (1.77) | (0.49) | (2.45) |
| Netback before hedging | $ 51.82 | $ 2.60 | $ 31.15 |
| Cash gains/(losses) | (4.05) | (0.13) | (2.17) |
| Netback after hedging | $ 47.77 | $ 2.47 | $ 28.98 |
| Netback before hedging ($ millions) | $ 408.2 | $ 163.6 | $ 571.8 |
| Netback after hedging ($ millions) | $ 376.2 | $ 155.7 | $ 531.9 |

(1) See "Non-GAAP Measure" in this MD&A.

Our crude oil properties accounted for 88% of our corporate netback before hedging for the first half of 2015 compared to 71% for the same period in 2014. Crude oil and natural gas netbacks per BOE decreased significantly for the three and six months ended June 30, 2015 compared to the same periods in 2014 primarily due to the decline in commodity prices over the past twelve months. Realized cash hedging gains and lower royalty rates helped to offset the impact of lower prices.

## General and Administrative Expenses

Total G&A expenses include cash G&A expenses and share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans") and our stock option plan. See Note 10 and Note 14 for further details.

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions) | 2015 | 2014 | 2015 | 2014 |
| Cash: | | | | |
| G&A expense | $ 19.9 | $ 18.7 | $ 41.3 | $ 39.2 |
| Share-based compensation expense | (1.2) | 10.7 | 6.0 | 17.5 |
| Non-Cash: | | | | |
| Share-based compensation expense | 4.6 | 3.5 | 9.6 | 6.5 |
| Equity swap loss/(gain) | 1.0 | (4.7) | (0.6) | (5.9) |
| Total G&A expenses | $ 24.3 | $ 28.2 | $ 56.3 | $ 57.3 |

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| (Per BOE) | 2015 | 2014 | 2015 | 2014 |
| Cash: | | | | |
| G&A expense | $ 2.03 | $ 1.97 | $ 2.19 | $ 2.14 |
| Share-based compensation expense | (0.13) | 1.12 | 0.32 | 0.95 |
| Non-Cash: | | | | |
| Share-based compensation expense | 0.47 | 0.37 | 0.51 | 0.35 |
| Equity swap loss/(gain) | 0.11 | (0.49) | (0.03) | (0.32) |
| Total G&A expenses | $ 2.48 | $ 2.97 | $ 2.99 | $ 3.12 |

Cash G&A expenses during the three and six months ended June 30, 2015 were $19.9 million or $2.03/BOE and $41.3 million or $2.19/BOE, respectively, compared to $18.7 million or $1.97/BOE and $39.2 million or $2.14/BOE for the same periods in 2014. The increase in cash G&A expenses from the prior year related primarily to one-time severance payments of $2.5 million during the first half of 2015.

During the quarter, our share price decreased by 15% resulting in a cash SBC recovery of $1.2 million or $0.13/BOE compared to an expense of $10.7 million or $1.12/BOE in the same period of 2014. We recorded non-cash SBC of $4.6 million or $0.47/BOE in the second quarter compared to $3.5 million or $0.37/BOE during the same period in 2014. The increase in non-cash SBC was due to additional grants issued under the plans.

We have hedged a portion of the outstanding cash settled grants under our LTI plans. As a result of the decrease in our share price during the quarter we recorded a non-cash mark-to-market loss of $1.0 million on these hedges. As of June 30, 2015 we had 524,000 units hedged at a weighted average price of $16.51/share.

Based on our increased production guidance and continued focus on cost control, we are reducing our 2015 guidance for cash G&A expenses to $2.25/BOE from $2.40/BOE. We do not provide guidance for SBC because it is dependent on our share price and our relative performance to our peers.

## Interest Expense

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions) | 2015 | 2014 | 2015 | 2014 |
| Interest on senior notes and bank facility | $ 15.9 | $ 16.0 | $ 32.7 | $ 30.6 |
| Non-cash interest expense | 0.2 | 0.5 | 0.5 | 1.1 |
| Total interest expense | $ 16.1 | $ 16.5 | $ 33.2 | $ 31.7 |

For the three and six month period ended June 30, 2015 we recorded total interest expense of $16.1 million and $33.2 million, respectively, compared to $16.5 million and $31.7 million for the same periods in 2014. The increase in interest expense for the six month period corresponds to an increase in higher interest rate senior notes following our September 2014 private placement of US$200 million and the impact of a weaker Canadian dollar on our U.S. dollar denominated interest expense. This was somewhat offset by senior note repayments of $88.9 million in June funded by lower rate floating bank debt, along with an overall decrease in our drawn credit facility balance following the receipt of net divestment proceeds of $187.8 million during the second quarter.

Non-cash amounts recorded in interest expense include amortization of deferred financing charges. See Note 11 for further details.

At June 30, 2015 approximately 93% of our debt was based on fixed interest rates and 7% on floating interest rates, with weighted average interest rates of 5.2% and 2.6%, respectively.

### Foreign Exchange

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions) | 2015 | 2014 | 2015 | 2014 |
| Realized loss/(gain) | $ 8.4 | $ 16.6 | $ (27.2) | $ 16.7 |
| Unrealized loss/(gain) | (36.1) | (23.8) | 103.7 | (22.5) |
| Total foreign exchange loss/(gain) | $ (27.7) | $ (7.2) | $ 76.5 | $ (5.8) |

For the three and six month period ended June 30, 2015 we recorded a net foreign exchange gain of $27.7 million and a net foreign exchange loss of $76.5 million, respectively, compared to gains of $7.2 million and $5.8 million for the same periods in 2014.

Realized losses in the second quarter included net payments of $7.1 million on our foreign exchange collars and forward contracts along with losses on day-to-day transactions recorded in foreign currencies. During the six months ended June 30, 2015 we recorded realized gains of $27.2 million primarily due to a $39.9 million gain on the unwind of our US$175 million foreign exchange swaps and losses of $15.7 million on our foreign exchange collars.

Unrealized gains and losses include the translation of U.S. dollar debt and working capital and unrealized gains or losses on our foreign exchange derivatives. See Note 12 for further details.

### Capital Investment

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions) | 2015 | 2014 | 2015 | 2014 |
| Capital spending | $ 148.0 | $ 204.4 | $ 315.0 | $ 422.2 |
| Office capital | 1.4 | 1.2 | 2.3 | 1.6 |
| Sub-total | $ 149.4 | $ 205.6 | $ 317.3 | $ 423.8 |
| Property and land acquisitions | $ (1.0) | $ 3.2 | $ (1.2) | $ 13.2 |
| Property divestments | (187.8) | 0.5 | (191.5) | (116.7) |
| Sub-total | $ (188.8) | $ 3.7 | $ (192.7) | $ (103.5) |
| Total | $ (39.4) | $ 209.3 | $ 124.6 | $ 320.3 |

Capital spending for the three and six months ended June 30, 2015 totaled $148.0 million and $315.0 million, respectively, compared to $204.4 million and $422.2 million for the same periods in 2014. Although spending has slowed in the first half of 2015 due to continued weakness in commodity prices, we continued to invest modestly in our core areas. During the second quarter we spent $110.6 million on our Fort Berthold crude oil properties, $17.3 million on our Canadian crude properties, $12.6 million on our Marcellus assets and $7.3 million on our deep gas properties in Canada.

During the second quarter of 2015, we completed the sale of non-core assets for combined proceeds of $187.8 million, net of closing costs, which includes the previously announced sale of our Pembina waterflood assets.

There were no acquisitions during the second quarter of 2015, although we recorded adjustments pertaining to prior period property acquisitions. In comparison, during the second quarter of 2014 we spent $3.2 million on minor property and land acquisitions.

Despite the impact of the weakening Canadian dollar on our U.S. dollar denominated spending we continue to expect annual capital spending of $540 million.

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

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions, except per BOE amounts) | 2015 | 2014 | 2015 | 2014 |
| DDA&A expense | $ 137.4 | $ 148.7 | $ 269.8 | $ 280.8 |
| Per BOE | $ 14.06 | $ 15.71 | $ 14.31 | $ 15.30 |

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three and six months ended June 30, 2015 DDA&A per BOE decreased when compared the same periods of 2014 primarily due to additional reserves recognized in the 2014 year-end reserves evaluation and the effect of the previous impairment on our book value.

### Impairment

Under U.S. GAAP, entities using full cost oil and gas accounting are subject to a ceiling test performed on a country by country basis using estimated after-tax future net cash flows discounted at 10% from proved reserves using SEC constant prices ("Standardized Measure"). SEC prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. The Standardized Measure is not related to Enerplus' investment criteria and is not a fair value based measurement, but rather a prescribed accounting calculation. Under U.S. GAAP impairments are not reversible in future periods.

The trailing twelve month average crude oil and natural gas prices decreased significantly in the first half of the year, resulting in non-cash impairments of $497.2 million and $764.9 million (before tax) for the three and six months ended June 30, 2015, respectively. We did not record any ceiling test impairments on our oil and natural gas properties in 2014. We expect the twelve month trailing prices used in the ceiling test calculation to decline further which may lead to additional write downs of our oil and natural gas properties. See Note 5 for trailing twelve month prices and further information.

### Asset Retirement Obligation

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are estimated by Enerplus based on our net ownership interest, anticipated costs to abandon and reclaim and the timing of the costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation to be $282.5 million at June 30, 2015 compared to $288.7 million at December 31, 2014. The decrease is primarily due to the Pembina property divestment in the second quarter of 2015. Asset retirement obligation settlements for the three and six months ended June 30, 2015 totaled $2.6 million and $6.5 million, respectively, compared to $4.2 million and $8.5 million for the same periods in 2014. See Note 8 for further information.

### Income Taxes

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions) | 2015 | 2014 | 2015 | 2014 |
| Current tax expense/(recovery) | $ (0.1) | $ 3.8 | $ – | $ 11.5 |
| Deferred tax expenses/(recovery) | (221.7) | 12.7 | (360.1) | 37.2 |
| Total tax expense/(recovery) | $ (221.8) | $ 16.5 | $ (360.1) | $ 48.7 |

We recorded a total tax recovery of $221.8 million and $360.1 million for the three and six months ended June 30, 2015, respectively, compared to a $16.5 million and $48.7 million expense for the same periods in 2014. The decrease in total tax expense is primarily due to lower income in

2015 which includes non-cash ceiling test impairments totaling $497.2 million and $764.9 million for the three and six months ended June 30, 2015, respectively.

Given the decrease in commodity prices and U.S. forecasted net income for the year, we expect current tax of less than 1% of our U.S. funds flow in 2015. Our U.S. current tax is comprised mainly of Alternative Minimum Tax ("AMT") payable with respect to our U.S. subsidiary. We expect to recover any AMT paid in future years as an offset to regular U.S. income taxes otherwise payable. We do not expect to pay any cash taxes in Canada in 2015.

As a result, an overall current tax recovery of $0.1 million and nil has been recognized for the three and six months ended June 30, 2015, respectively, compared to a $3.8 million and $11.5 million expense for the same periods in 2014.

These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisitions and divestment activity. See Note 13 for further information.

### SELECTED QUARTERLY CANADIAN AND U.S. FINANCIAL RESULTS

| | Three months ended June 30, 2015 | | | Three months ended June 30, 2014 | | |
|---|---|---|---|---|---|---|
| (CDN$ millions, except per unit amounts) | Canada | U.S. | Total | Canada | U.S. | Total |
| **Average Daily Production Volumes[1]** | | | | | | |
| Crude oil (bbls/day) | 15,462 | 25,660 | 41,122 | 17,184 | 22,679 | 39,863 |
| Natural gas liquids (bbls/day) | 2,136 | 3,009 | 5,145 | 2,476 | 1,160 | 3,636 |
| Natural gas (Mcf/day) | 144,788 | 222,183 | 366,971 | 156,401 | 206,528 | 362,929 |
| Total average daily production (BOE/day) | 41,730 | 65,699 | 107,429 | 45,727 | 58,260 | 103,987 |
| **Pricing[2]** | | | | | | |
| Crude oil (per bbl) | $ 55.86 | $ 59.71 | $ 58.26 | $ 92.90 | $ 96.41 | $ 94.90 |
| Natural gas liquids (per bbl) | 33.58 | 11.87 | 20.88 | 57.01 | 35.00 | 49.98 |
| Natural gas (per Mcf) | 2.68 | 1.70 | 2.09 | 4.32 | 3.80 | 4.02 |
| **Capital expenditures** | | | | | | |
| Capital spending | $ 24.6 | $ 123.4 | $ 148.0 | $ 60.4 | $ 144.0 | $ 204.4 |
| Acquisitions | 0.8 | (1.8) | (1.0) | – | 3.2 | 3.2 |
| Divestments | (187.1) | (0.7) | (187.8) | – | 0.5 | 0.5 |
| **Netback Before Hedging** | | | | | | |
| Oil and natural gas sales | $ 120.7 | $ 177.7 | $ 298.4 | $ 226.0 | $ 278.5 | $ 504.5 |
| Royalties | (11.7) | (35.0) | (46.7) | (35.1) | (54.5) | (89.6) |
| Production taxes | (0.9) | (13.3) | (14.2) | (1.9) | (18.1) | (20.0) |
| Cash operating expense | (49.3) | (30.0) | (79.3) | (62.2) | (24.0) | (86.2) |
| Transportation expense | (5.8) | (22.2) | (28.0) | (5.9) | (16.7) | (22.6) |
| Netback before hedging | $ 53.0 | $ 77.2 | $ 130.2 | $ 120.9 | $ 165.2 | $ 286.1 |
| **Other Expenses** | | | | | | |
| Commodity derivative instruments loss/(gain) | $ 19.8 | $ – | $ 19.8 | $ 44.0 | $ – | $ 44.0 |
| General and administrative expense[3] | 19.2 | 5.1 | 24.3 | 22.6 | 5.6 | 28.2 |
| Current income tax expense/(recovery) | (0.4) | 0.3 | (0.1) | (0.2) | 4.0 | 3.8 |

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) Includes share-based compensation.

| (CDN$ millions, except per unit amounts) | Six months ended June 30, 2015 Canada | U.S. | Total | Six months ended June 30, 2014 Canada | U.S. | Total |
|---|---|---|---|---|---|---|
| **Average Daily Production Volumes[1]** | | | | | | |
| Crude oil (bbls/day) | 16,213 | 24,030 | 40,243 | 16,882 | 21,935 | 38,817 |
| Natural gas liquids (bbls/day) | 2,247 | 2,197 | 4,444 | 2,508 | 942 | 3,450 |
| Natural gas (Mcf/day) | 140,129 | 216,707 | 356,836 | 154,027 | 200,879 | 354,906 |
| Total average daily production (BOE/day) | 41,816 | 62,345 | 104,160 | 45,061 | 56,357 | 101,418 |
| **Pricing[2]** | | | | | | |
| Crude oil (per bbl) | $ 48.37 | $ 53.56 | $ 51.35 | $ 89.55 | $ 96.09 | $ 93.25 |
| Natural gas liquids (per bbl) | 31.26 | 11.62 | 21.55 | 63.16 | 43.01 | 57.66 |
| Natural gas (per Mcf) | 2.90 | 1.95 | 2.32 | 4.70 | 4.28 | 4.46 |
| **Capital expenditures** | | | | | | |
| Capital spending | $ 101.5 | $ 213.5 | $ 315.0 | $ 188.0 | $ 234.2 | $ 422.2 |
| Acquisitions | 2.0 | (3.2) | (1.2) | – | 13.2 | 13.2 |
| Divestments | (188.0) | (3.5) | (191.5) | (67.7) | (49.0) | (116.7) |
| **Netback Before Hedging** | | | | | | |
| Oil and natural gas sales | $ 228.6 | $ 313.9 | $ 542.5 | $ 446.1 | $ 553.5 | $ 999.6 |
| Royalties | (24.0) | (61.8) | (85.8) | (69.1) | (107.8) | (176.9) |
| Production taxes | (2.7) | (22.3) | (25.0) | (3.9) | (35.9) | (39.8) |
| Cash operating expense | (106.4) | (59.8) | (166.2) | (124.4) | (41.7) | (166.1) |
| Transportation expense | (12.0) | (42.5) | (54.5) | (11.8) | (33.2) | (45.0) |
| Netback before hedging | $ 83.5 | $ 127.5 | $ 211.0 | $ 236.9 | $ 334.9 | $ 571.8 |
| **Other Expenses** | | | | | | |
| Commodity derivative instruments loss/(gain) | $ (30.6) | $ – | $ (30.6) | $ 76.7 | $ – | $ 76.7 |
| General and administrative expense[3] | 42.7 | 13.6 | 56.3 | 45.9 | 11.4 | 57.3 |
| Current income tax expense/(recovery) | (0.4) | 0.4 | – | (0.4) | 11.9 | 11.5 |

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) Includes share-based compensation.

## 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 |
|---|---|---|---|---|
| **2015** | | | | |
| Second Quarter | $ 251.7 | $ (312.5) | $ (1.52) | $ (1.52) |
| First Quarter | 205.0 | (293.2) | (1.42) | (1.42) |
| Total 2015 | $ 456.7 | $ (605.7) | $ (2.94) | $ (2.94) |
| **2014** | | | | |
| Fourth Quarter | $ 325.3 | $ 151.7 | $ 0.74 | $ 0.73 |
| 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 2014 | $ 1,526.2 | $ 299.1 | $ 1.46 | $ 1.44 |
| **2013** | | | | |
| Fourth Quarter | $ 332.4 | $ 29.6 | $ 0.15 | $ 0.15 |
| Third Quarter | 365.4 | (3.7) | (0.02) | (0.02) |
| Second Quarter | 341.3 | 38.5 | 0.19 | 0.19 |
| First Quarter | 313.4 | (16.4) | (0.08) | (0.08) |
| Total 2013 | $ 1,352.5 | $ 48.0 | $ 0.24 | $ 0.24 |

Oil and natural gas sales increased during the second quarter compared to the first quarter of 2015 as production volumes increased and oil prices improved. From the first quarter of 2013, oil and natural gas sales increased steadily until the third quarter of 2014 when realized commodity prices began to decline significantly. Net income in the first half of 2015 was impacted by asset impairments related to the decrease in the trailing twelve month average commodity prices used to calculate impairments. We did not record any asset impairments in 2013 or 2014.

### LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, which is a senior debt to EBITDA threshold of 3.5x for a period of up to six months, after which it drops to 3.0x. At June 30, 2015 our senior debt to EBITDA ratio was 1.5x and our debt to funds flow ratio was 1.6x. The debt to funds flow ratio is often used by investors and analysts to evaluate our liquidity, however, this measure is not part of our debt covenants.

Total debt net of cash at June 30, 2015 was $1,120.7 million compared to $1,134.9 million at December 31, 2014. Total debt was comprised of $80.4 million of bank indebtedness and $1,041.3 million of senior notes less $1.0 million in cash. At June 30, 2015 we were approximately 8% drawn on our $1.0 billion senior unsecured bank facility.

During the second quarter, we repaid debt of $88.9 million on the final maturities of our US$40.0 million and $40.0 million senior notes. Following the October 1, 2015 repayment of US$10.8 million on our maturing US$54 million senior notes, we have no scheduled debt repayments until June of 2017, with remaining maturities extending to 2026.

Our working capital deficiency, excluding cash and current deferred financial and tax balances, decreased to $164.7 million at June 30, 2015 from $290.6 million at December 31, 2014. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by funds flow, was 112% and 147% for the three and six months ended June 30, 2015, respectively, compared to 120% and 119% for the same periods in 2014. We have continued to maintain our financial flexibility through an ongoing focus on cost efficiencies and the success of our non-core asset divestment program. After adjusting for net acquisition and divestment proceeds, our adjusted payout ratio for the six months ended June 30, 2015 decreases to 75%.

As previously announced, in order to maintain our balance sheet strength we have reduced our monthly dividend by 44% to $0.05/share from $0.09/share effective with our March 2015 dividend, paid in April. Although we have revised capital spending guidance to $540 million to accelerate North Dakota oil well completions, our overall capital spending budget remains 33% lower than 2014 spending levels.

We have a $1.0 billion senior, unsecured, covenant-based bank credit facility that matures on October 31, 2017. Drawn fees range between 150 and 315 basis points over Banker's Acceptance rates, with current drawn fees of 170 basis points. The bank credit facility ranks equally with our senior, unsecured, covenant-based notes. At June 30, 2015 we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at June 30, 2015:

| Covenant Description | | June 30, 2015 |
|---|---|---|
| **Bank Credit Facility:** | **Maximum Ratio** | |
| Senior Debt to EBITDA | 3.5 x | 1.5 x |
| Total Debt to EBITDA | 4.0 x | 1.5 x |
| Total Debt to Capitalization(1) | 50% – 55% | 29% |
| **Senior Notes:** | **Maximum Ratio** | |
| Senior Debt to EBITDA(2) | 3.0 x – 3.5x | 1.5 x |
| Maximum debt to consolidated present value of total proven reserves | 60% | 37% |
| | **Minimum Ratio** | |
| EBITDA to Interest | 4.0 x | 12.1 x |

### Definitions

"Senior Debt" is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.

"EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, accretion and non-cash gains and losses. EBITDA is calculated on a trailing twelve month basis and is adjusted for material acquisitions and divestments. EBITDA for the three months and the trailing twelve months ended June 30, 2015 were $176.2 million and $780.6 million, respectively.

"Total Debt" is calculated as the sum of Senior Debt plus subordinated debt. Enerplus currently does not have any subordinated debt.

"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

### Footnotes

(1) Upon completion of a material acquisition, the Total Debt to Capitalization maximum ratio may increase to 55% for a period extending to and including the second full fiscal quarter after the completion of the acquisition.

(2) Senior Debt to EBITDA maximum ratio for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.

## Dividends

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions, except per share amounts) | 2015 | 2014 | 2015 | 2014 |
| Cash dividends | $ 30.9 | $ 50.5 | $ 78.3 | $ 92.7 |
| Stock dividend plan | – | 4.7 | – | 17.4 |
| Total dividends to shareholders | $ 30.9 | $ 55.2 | $ 78.3 | $ 110.1 |
| Per weighted average share (Basic) | $ 0.15 | $ 0.27 | $ 0.38 | $ 0.54 |

During the three and six months ended June 30, 2015 we reported total dividends of $30.9 million ($0.15/share) and $78.3 million ($0.38/share), respectively, compared to $55.2 million ($0.27/share) and $110.1 million ($0.54/share) for the same periods in 2014.

Effective with the April 2015 payment, we reduced the monthly dividend by 44% from $0.09 per share to $0.05 per share to preserve our balance sheet strength. During the second quarter, our dividends represented approximately 19% of our funds flow and at current levels we expect to spend approximately $124 million annually on dividends, a decrease from $221.1 million in 2014. Additionally, in September 2014 we elected to suspend our stock dividend plan, thereby eliminating any dilution resulting from issuing shares as part of our dividend plan.

The dividend is an important part of our strategy to create shareholder value and we will continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

## Shareholders' Capital

| | Six months ended June 30, | |
|---|---|---|
| | 2015 | 2014 |
| Share capital ($ millions) | $ 3,126.6 | $ 3,102.2 |
| Common shares outstanding (thousands) | 206,224 | 204,768 |
| Weighted average shares outstanding – basic (thousands) | 206,028 | 203,671 |
| Weighted average shares outstanding – diluted (thousands) | 206,028 | 207,563 |

During the second quarter of 2015 a total of 45,000 shares (2014 – 929,000) and $0.6 million of additional equity (2014 – $17.8 million) was issued pursuant to the stock option plan and the currently inactive stock dividend plan. For the six months ended June 30, 2015 a total of 492,000 shares (2014 – 2,010,000) and $6.3 million of additional equity (2014 – $36.7 million) was issued pursuant to the stock option plan, the treasury settled Restricted Share Unit plan and the currently inactive stock dividend plan. For further details see Note 14.

At June 30, 2015 we had 206,224,000 shares outstanding (2014 – 204,768,000) and at August 6, 2015 we had 206,224,000 shares outstanding.

### U.S. Filing Status

Pursuant to U.S. securities regulations, we are required to reassess our U.S. securities filing status annually at June 30. As at June 30, 2015 we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

## 2015 GUIDANCE

We have increased our production guidance and have reduced our operating cost and G&A expense guidance by a total of $0.65/BOE. All other guidance has been maintained and is summarized below. This guidance does not include any unannounced acquisitions or divestments.

| Summary of 2015 Expectations | Target |
|---|---|
| Average annual production | 100,000 – 104,000 BOE/day (from 97,000 – 103,000 BOE/day) |
| Capital spending | $540 million |
| Production mix (volumes) | 44,000 – 46,000 bbls/day of crude oil and natural gas liquids |
| Average royalty and production tax rate (% of gross sales, before transportation) | 21% |
| Operating expenses | $9.25/BOE (from $9.75/BOE) |
| Transportation costs | $3.00/BOE |
| Cash G&A expenses | $2.25/BOE (from $2.40/BOE) |
| U.S. cash taxes (% of U.S. funds flow) | < 1% |

## 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 Issuer's Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at June 30, 2015, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on April 1, 2015 and ended June 30, 2015 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 2015 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our balance sheet and funds flow; our commodity and foreign exchange risk management programs in 2015 and in the future; the results from our drilling program and the timing of related production; oil and natural gas prices, including twelve month trailing prices used in calculation of a ceiling test impairment under U.S. GAAP; 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 and transportation costs; capital spending levels in 2015 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 royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and expectations regarding Canadian cash taxes; future debt and working capital levels and debt-to-funds-flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; our future acquisitions and dispositions, including timing thereof and expected use of proceeds therefrom; and the amount of future cash dividends that we may pay to our shareholders.*

*The forward-looking information contained in this MD&A reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in further curtailment of production and/or reduced realized prices; current commodity price and cost assumptions; 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; 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. In addition, our 2015 guidance contained in this MD&A is based on the following July 22, 2015 forward prices: a WTI price of US$51.99/bbl, a NYMEX price of US$2.89/Mcf, and AECO price of $2.75/GJ and a CDN/USD exchange rate of 1.27.*

*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 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, including further decline of, 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; curtailment of our production due to low realized prices or lack of adequate infrastructure; our risk management programs, including commodity hedging, being less effective in protecting our balance sheet and funds flow than anticipated; 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; changes in estimates of our reserves and resource volumes; limited, unfavorable or a lack of access to capital markets; our inability to comply with covenants under our bank credit facility and senior notes; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; failure to complete any of the anticipated acquisitions or dispositions; 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 our Annual MD&A and in our other public filings).*