Q1 2016

enerPLUS

FIRST QUARTER REPORT
THREE MONTHS ENDED MARCH 31, 2016

SELECTED FINANCIAL RESULTS	Three months ended March 31, 2016	2015
Financial (000's)		
Funds Flow[4]	$ 41,727	$ 109,164
Dividends to Shareholders	14,464	47,359
Net Income/(Loss)	(173,666)	(293,206)
Debt Outstanding – net of cash	992,837	1,272,204
Capital Spending	43,276	167,011
Property and Land Acquisitions	3,554	(236)
Property Divestments	187,768	3,712
Debt to Funds Flow Ratio[4]	2.3x	1.7x
Financial per Weighted Average Shares Outstanding		
Funds Flow	$ 0.20	$ 0.53
Net Income/(Loss)	(0.84)	(1.42)
Weighted Average Number of Shares Outstanding (000's)	206,716	205,845
Selected Financial Results per BOE[1][2]		
Oil & Natural Gas Sales[3]	$ 19.14	$ 26.89
Royalties and Production Taxes	(3.95)	(5.50)
Commodity Derivative Instruments	4.45	9.56
Cash Operating Expenses	(8.12)	(9.56)
Transportation Costs	(2.89)	(2.92)
General and Administrative Expenses	(2.07)	(2.36)
Cash Share-Based Compensation	(0.08)	(0.80)
Interest, Foreign Exchange and Other Expenses	(1.81)	(3.28)
Current Income Tax Recovery	0.02	–
Funds Flow	$ 4.69	$ 12.03

SELECTED OPERATING RESULTS	Three months ended March 31, 2016	2015
Average Daily Production[2]		
Crude Oil (bbls/day)	39,508	39,355
Natural Gas Liquids (bbls/day)	5,494	3,735
Natural Gas (Mcf/day)	317,150	346,589
Total (BOE/day)	97,860	100,855
% Crude Oil & Natural Gas Liquids	46%	43%
Average Selling Price[2][3]		
Crude Oil (per bbl)	$ 31.59	$ 44.04
Natural Gas Liquids (per bbl)	11.34	22.48
Natural Gas (per Mcf)	1.77	2.58
Net Wells Drilled	12	28

(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) Before transportation costs, royalties and commodity derivative instruments.
(4) These non-GAAP measures may not be directly comparable to similar measures presented by other entities. See "Non-GAAP Measures" section in the following MD&A.

Average Benchmark Pricing	Three months ended March 31, 2016	2015
WTI crude oil (US$/bbl)	$ 33.45	$ 48.64
AECO natural gas – monthly index (CDN$/Mcf)	2.11	2.95
AECO natural gas – daily index (CDN$/Mcf)	1.83	2.75
NYMEX natural gas – last day (US$/Mcf)	2.09	2.98
USD/CDN exchange rate	1.37	1.24

Share Trading Summary For the three months ended March 31, 2016	CDN* – ERF (CDN$)	U.S.** – ERF (US$)
High	$ 5.37	$ 4.03
Low	$ 2.68	$ 1.84
Close	$ 5.09	$ 3.93

* TSX and other Canadian trading data combined.

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

2016 Dividends per Share	CDN$	US$(1)
January	$ 0.03	$ 0.02
February	$ 0.03	$ 0.02
March	$ 0.03	$ 0.02
First Quarter Total	$ 0.09	$ 0.06

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

PRESIDENT'S MESSAGE

During the first quarter, we continued to position our company to deliver long-term profitability in a lower commodity price environment. Our focus on reducing costs and driving efficiencies across the organization has resulted in a meaningful reduction to our cost structure. As a result, we are reducing our combined operating, transportation and G&A cost guidance by $1.30 per BOE in 2016. In addition, we have been delivering on our portfolio optimization objectives with non-core divestments generating net proceeds of $188 million in the first quarter, further strengthening our Company's balance sheet. Operationally, our assets continue to deliver strong results and we remain on track to achieve our targets.

Production averaged 97,860 BOE per day during the quarter, including approximately 45,000 barrels per day of crude oil and natural gas liquids. Total production was down 8% from the previous quarter primarily as a result of non-core divestment activity during the fourth quarter of 2015 and first quarter of 2016, in which we divested properties with associated production of approximately 9,100 BOE per day. The divested production was approximately 90% natural gas weighted and, as a result, our crude oil and natural gas liquids weighting increased to 46% in the first quarter, from 43% in the previous quarter.

We continued to see outperformance from our North Dakota wells along with strong production results from our Canadian oil portfolio during the quarter. As a result, and despite the previously announced second quarter divestment of 2,300 BOE per day, we are maintaining our 2016 production guidance range of 90,000 to 94,000 BOE per day and 43,000 to 45,000 barrels per day of crude oil and natural gas liquids.

First quarter funds flow was $41.7 million ($0.20 per share), down approximately 60% from the fourth quarter of 2015 as a result of significantly lower crude oil and natural gas prices and lower realized gains on crude oil and natural gas hedging contracts.

We recorded a net loss of $173.7 million ($0.84 per share) in the first quarter. Our first quarter earnings benefited from a combined gain of $152.2 million on property divestments and the repurchase of a portion of our outstanding senior notes. These gains were offset by non-cash charges of $304.7 million related to asset impairment and a valuation allowance taken on our deferred tax asset as a result of the decline in 12-month trailing average commodity prices.

Our focus on maintaining our balance sheet strength and preserving the value of our high quality inventory during this period of low commodity prices resulted in a 50% reduction in capital spending from the fourth quarter of 2015, to $43.3 million. Capital spending was focused on our crude oil properties with $19.8 million directed to North Dakota and $19.1 million directed to our Canadian oil portfolio. We continue to budget 2016 capital spending of $200 million, with approximately 90% allocated to our crude oil plays (65% North Dakota, 25% Canada).

Our ongoing cost reduction efforts are delivering strong results. First quarter operating expenses of $8.15 per BOE were 6% lower than the fourth quarter of 2015 and 16% lower than the first quarter of 2015, despite lower volumes. Based on cost savings to date, the strengthening Canadian dollar relative to our U.S. dollar denominated operating costs, and the previously announced divestment of our higher cost northwest Alberta assets, we are reducing our 2016 guidance for operating expenses to $8.50 per BOE from $9.50 per BOE. We are also reducing our transportation cost guidance to $3.10 per BOE from $3.30 per BOE as a result of the strengthening Canadian dollar.

Cash G&A expenses during the first quarter were $2.07 per BOE, down 12% from the same period in 2015 and up 18% from the fourth quarter of 2015 largely due to severance payments incurred in the first quarter. As a result of the reduction of our workforce to better align with our more focused asset base and improved organizational efficiencies, we are reducing our 2016 guidance for cash G&A expenses to $2.00 per BOE from $2.10 per BOE.

Overall, taking into account our reduced operating, transportation and G&A expense guidance, we expect our 2016 cash costs to be approximately $1.30 per BOE lower than previously forecast.

As previously announced, effective with the April 2016 payment, we reduced the monthly dividend from $0.03 per share to $0.01 per share. This reduction reflected the need to rebalance the dividend level to better align with reduced funds flow in the context of the sustained low commodity price environment.

We further strengthened our balance sheet during the first quarter, ending the period with total debt, net of cash, of $992.8 million compared to $1,216.2 million at December 31, 2015. The $223 million reduction in total debt was a result of applying divestment proceeds against outstanding debt combined with the strengthening Canadian dollar relative to our U.S. dollar denominated senior notes. Total debt was comprised of $844.5 million of senior notes and $149.6 million of bank indebtedness (19% drawn on our $800 million facility) less $1.3 million in cash. At March 31, 2016, our senior debt to EBITDA ratio was 1.6 times and our debt to funds flow ratio was 2.3 times.

We had continued success in divesting non-core assets during the quarter which provided net proceeds of approximately $188 million. These proceeds, along with our largely undrawn bank credit facility, were used to fund the repurchase of US$172 million of our senior notes during the quarter, and a total of US$267 million of senior notes to date. The repurchases were completed at prices ranging from 90% of par to par value, with no penalty or make-whole payments required, resulting in a total gain of $19 million. As a result of replacing fixed term, higher interest rate senior debt with lower interest rate bank debt and using divestment proceeds to repay outstanding debt, we expect to save approximately US$13 million in interest expense on an annualized basis. Utilizing a portion of our bank credit facility in place of the senior notes provides additional flexibility within our capital structure to reduce our leverage further as cash becomes available.

Subsequent to the quarter, we announced an additional non-core divestment of certain assets located in northwest Alberta for proceeds of $95.5 million, subject to closing adjustments. Expected annual average 2016 production associated with these assets is approximately 2,300 BOE per day (50% natural gas). This divestment is expected to close in the second quarter of 2016 and we expect to realize a gain of approximately $70 million as a result of the sale. Upon closing, this will bring total 2016 divestment proceeds to $283 million.

In connection with our non-core assets sales, we have materially reduced the Company's future abandonment liabilities. Since the start of 2015, we have reduced our asset retirement obligations by over 30%.

Production and Capital Spending(1)

	Three months ended March 31, 2016	
	Average Production Volumes	**Capital Spending** ($ millions)
Crude Oil & NGLs (bbls/day)		
Canada	15,990	19.1
United States	29,012	20.7
Total Crude Oil & NGLs (bbls/day)	**45,002**	**39.8**
Natural Gas (Mcf/day)		
Canada	99,539	–
United States	217,611	3.5
Total Natural Gas (Mcf/day)	**317,150**	**3.5**
Company Total (BOE/day)	**97,860**	**43.3**

(1) Table may not add due to rounding.

Asset Activity

North Dakota

North Dakota production averaged 29,200 BOE per day during the first quarter, largely flat from the previous quarter and up 36% from the same period in 2015. We spent $19.8 million in North Dakota in the quarter drilling 4.4 net wells and bringing 2.5 net wells on-stream. Our well performance continues to be strong, with the two operated on-stream wells in the quarter delivering initial 30-day production rates of 1,990 and 1,750 BOE per day. Subsequent to the quarter, two further wells were brought on-stream that have averaged in excess of 2,000 BOE per day in the first 30 days of production. Well costs continue to trend down due to reduced drilling days, completions optimization and changes to facilities design. Our total drilling, completion, tie-in and facilities costs are currently US$8.5 million, down approximately 35% from 2014 levels.

We continue to run a single drilling rig in North Dakota given the sustained low commodity price environment but retain the flexibility to increase activity quickly given our inventory of drilled uncompleted wells, which stood at approximately 11 at the end of the first quarter. Our 2016 capital program is primarily focused in North Dakota, where we expect to spend approximately $130 million during the full year 2016, keeping North Dakota production largely flat.

Canada

Total production from Canada averaged 32,590 BOE per day during the quarter. Activity was focused on our waterflood assets at Cadogan, Giltedge and southeast Saskatchewan, where we drilled 4 producers and 3 injector wells. Results from the program have exceeded expectations with the wells producing at, or above, our type curve forecast. Production from the waterflood assets averaged 17,500 BOE per day during the quarter. Activity in Canada during the rest of 2016 will be largely focused on performance and cost optimization work.

Marcellus

Marcellus production averaged 190 MMcf per day during the first quarter, down approximately 7% from the previous quarter due to continued low levels of activity as a result of weak regional natural gas pricing. Capital spending in the quarter was $3.5 million, with 1.3 net wells brought on-stream. We continue to plan for modest levels of activity in the Marcellus, forecasting full year 2016 spending of $20 million, a reduction of approximately 37% from 2015 spending.

Net Drilling Activity(1) – for the three months ended March 31, 2016

	Wells Drilled	Wells On-stream
Crude Oil		
Canada	7.0	6.0
United States	4.4	2.5
Total Crude Oil	**11.4**	**8.5**
Natural Gas		
Canada	–	–
United States	0.1	1.3
Total Natural Gas	**0.1**	**1.3**
Company Total	**11.5**	**9.8**

(1) Table may not add due to rounding.

Crude Oil & Natural Gas Pricing

The WTI benchmark crude oil price fell by 21% versus the previous quarter as seasonal refinery outages combined with continued oversupply drove U.S. oil inventories to near-maximum levels. This supply imbalance pushed WTI prices to a low of US$26.05 per barrel in February before improving by the end of the quarter as refinery demand returned and there were growing indications of supply declines in North America and elsewhere. Modestly weaker crude oil differentials in both Canada and the U.S. also contributed to the weakness in realized oil prices during the quarter. Our average Bakken realized crude oil price differential was US$8.38 per barrel below WTI in the quarter.

NYMEX natural gas prices fell by 8% and AECO monthly prices fell by approximately 20% compared to the previous quarter. Both markets remained weak in response to continued high production with lower than normal seasonal demand that resulted in significant storage surpluses across North America relative to the first quarter of 2015.

Our overall realized natural gas price outperformed changes in NYMEX and AECO prices due to improving differentials in the Marcellus. Weaker NYMEX prices narrowed Marcellus benchmark differentials, resulting in an average Marcellus realized price differential of US$0.91 per Mcf below NYMEX, a 19% improvement from the previous quarter. We continue to expect our realized Marcellus differentials in 2016 to improve relative to recent years due to reduced industry spend and the continued build out of regional take-away capacity.

Risk Management

We continue to protect a portion of our funds flow through commodity hedging and have added additional price protection on both our crude oil and natural gas production in 2017. Currently, we have a combination of swaps and collars in 2016 and 2017 covering approximately 31% and 20% respectively, of forecast net oil production, after royalties. For natural gas, we have a combination of swaps and collars in 2016 and 2017 covering approximately 31% and 16% respectively, of forecast net natural gas production, after royalties.

Commodity Hedging Detail (as at May 2, 2016)

	Crude Oil (US$/bbl)[1]			NYMEX Natural Gas (US$/Mcf)[1]		
	Apr 1, 2016 – Jun 30, 2016	Jul 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Dec 31, 2017	Apr 1, 2016 – Oct 31, 2016	Nov 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Dec 31, 2017
Swaps						
Sold Swaps	$ 64.28	–	–	$ 2.53	$ 2.48	–
Volume (bbl/d or Mcf/d)	3,000	–	–	50,000	25,000	–
% of net production	10%	–	–	23%	11%	–
3 Way Collars						
Sold Puts	$ 50.13	$ 49.78	$ 35.67	$ 2.50	$ 2.50	$ 2.00
Volume (bbl/d or Mcf/d)	8,000	8,000	6,000	25,000	25,000	35,000
% of net production	26%	26%	20%	11%	11%	16%
Purchased Puts	$ 64.38	$ 63.98	$ 48.18	$ 3.00	$ 3.00	$ 2.67
Volume (bbl/d or Mcf/d)	8,000	8,000	6,000	25,000	25,000	35,000
% of net production	26%	26%	20%	11%	11%	16%
Sold Calls	$ 79.38	$ 79.63	$ 60.00	$ 3.75	$ 3.75	$ 3.32
Volume (bbl/d or Mcf/d)	8,000	8,000	6,000	25,000	25,000	35,000
% of net production	26%	26%	20%	11%	11%	16%
Collars						
Purchased Puts	$ 33.41	–	–	–	–	–
Volume (bbl/d or Mcf/d)	1,670	–	–	–	–	–
% of net production	5%	–	–	–	–	–
Sold Puts	$ 41.75	–	–	–	–	–
Volume (bbl/d or Mcf/d)	1,670	–	–	–	–	–
% of net production	5%	–	–	–	–	–

(1) Based on weighted average price (before premiums), assuming average annual production of 92,000 BOE/day for 2016 and 2017, less royalties and production taxes of 23% in aggregate.

Revised 2016 Guidance

We have revised our full year 2016 guidance as a result of further reductions to our cost structure related to operating, transportation and G&A expenses. Capital spending and production guidance remain unchanged. The revised guidance considers the announced divestment of our northwest Alberta assets expected to close during the second quarter.

Summary of 2016 Expectations	Revised Guidance	Original Guidance
Capital spending	$200 million	$200 million
Average annual production	90,000 – 94,000 BOE/day	90,000 – 94,000 BOE/day
Crude oil and natural gas liquids volumes	43,000 – 45,000 BOE/day	43,000 – 45,000 BOE/day
Average royalty and production tax rate	23%	23%
Operating expenses	$8.50/BOE	$9.50/BOE
Transportation expense	$3.10/BOE	$3.30/BOE
Cash G&A expenses	$2.00/BOE	$2.10/BOE

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation

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

The following discussion and analysis of financial results is dated May 5, 2016 and is to be read in conjunction with:

- the unaudited interim consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three months ended March 31, 2016 and 2015 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2015 and 2014 and for the years ended December 31, 2015, 2014 and 2013 (the "Financial Statements"); and
- our MD&A for the year ended December 31, 2015 (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 note 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 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.

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. Netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating expenses and transportation costs.

Calculation of Netback ($ millions)	Three months ended March 31, 2016	2015
Oil and natural gas sales	$ 170.5	$ 244.1
Less:		
Royalties	(27.8)	(39.1)
Production taxes	(7.4)	(10.8)
Cash operating expenses[1]	(72.3)	(86.8)
Transportation costs	(25.7)	(26.5)
Netback before hedging	$ 37.3	$ 80.9
Cash gains/(losses) on derivative instruments	39.6	86.8
Netback after hedging	$ 76.9	$ 167.7

(1) Operating costs adjusted to exclude non-cash losses on fixed price electricity swaps of $0.3 million in the three months ended March 31, 2016 and $0.9 million in the three months ended March 31, 2015.

"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 from 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 March 31, 2016	2015
Cash flow from operating activities	$ 69.7	$ 131.1
Asset retirement obligation expenditures	2.5	3.9
Changes in non-cash operating working capital	(30.5)	(25.8)
Funds Flow	$ 41.7	$ 109.2

"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 twelve 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 dividends plus capital and office expenditures divided by Funds Flow.

Calculation of Adjusted Payout Ratio ($ millions)	Three months ended March 31, 2016	2015
Dividends	$ 14.5	$ 47.4
Capital and office expenditures	43.3	167.9
Sub-total	$ 57.8	$ 215.3
Funds Flow	$ 41.7	$ 109.2
Adjusted Payout Ratio (%)	138%	197%

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 proved 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 during the first quarter, coupled with the success of our non-core asset divestment program, has allowed us to improve our financial flexibility and balance sheet strength. We remain well positioned to meet our average annual production guidance, despite our additional second quarter asset divestment, and are revising our operating expense, transportation cost and general and administrative ("G&A") expense guidance downwards by a combined total of $1.30/BOE to reflect cost savings to date.

Average daily production for the first quarter totaled 97,860 BOE/day, exceeding our annual guidance range of 90,000 – 94,000 BOE/day due to outperformance from our North Dakota wells and strong production results from our Canadian oil and natural gas properties. Compared to the fourth quarter of 2015, production decreased as a result of divestments with associated production of approximately 3,700 BOE/day in the fourth quarter and 5,400 BOE/day during the first quarter. Despite the previously announced second quarter sale of assets located in northwest Alberta with expected average 2016 production of 2,300 BOE/day, we are maintaining our average annual production guidance of 90,000 – 94,000 BOE/day and our liquids production guidance of 43,000 – 45,000 BOE/day.

Capital spending is on track, with $43.3 million spent in the first quarter. We continue to expect spending of $200 million in 2016, with the majority of our investment directed to our Fort Berthold properties.

Operating expenses came in below guidance for the quarter, at $8.15/BOE compared to annual guidance of $9.50/BOE. Compared to the fourth quarter of 2015, operating cost savings were a result of ongoing cost structure improvements. Based on cost savings to date, the additional divestment in the second quarter and the impact of a strengthening Canadian dollar on our U.S. dollar denominated expenditures, we are reducing our 2016 guidance for operating expenses to $8.50/BOE.

G&A expenses were also below guidance, totaling $2.07/BOE in the first quarter compared to annual guidance of $2.10/BOE, as a result of our staffing reductions and ongoing focus on cost control. Accordingly, we are revising our G&A guidance downwards to $2.00/BOE.

We continued to focus our portfolio during 2016, with first quarter asset divestment proceeds of $187.8 million, net of closing costs. Including the previously announced second quarter sale of non-core Canadian assets, we expect total proceeds of approximately $283 million year to date and gains on dispositions of approximately $215 million. In addition, we expect these divestments to reduce our asset retirement obligations by $22.7 million.

These asset divestment proceeds, along with our largely undrawn bank credit facility, provided funding for the repurchase of US$172 million of our senior notes during the quarter, and a total of US$267 million of senior notes to date. The senior note repurchases were completed at prices between 90% of par and par value resulting in an expected total gain of $19 million. At March 31, 2016, total debt net of cash was $992.8 million, a decrease of $223.4 million compared to $1,216.2 million at December 31, 2015. Our Senior Debt to EBITDA and Debt to Funds Flow ratios at March 31, 2016 were 1.6x and 2.3x, respectively; an improvement from 2.2x and 2.5x, respectively, at December 31, 2015.

We reported a net loss of $173.7 million and Funds Flow of $41.7 million during the first quarter, compared to a net loss of $625.0 million and Funds Flow of $102.7 million in the fourth quarter of 2015. Our first quarter earnings benefited from gains of $145.1 million on property divestments and $7.1 million on the repurchase of senior notes. These gains were offset by a non-cash asset impairment charge of $46.2 million and a non-cash valuation allowance of $258.5 million on our deferred tax asset, both recorded under U.S. GAAP as a result of the continued decline in twelve month trailing average commodity prices. Our commodity hedging program continued to provide protection, contributing total gains of $13.5 million to earnings and cash gains of $39.6 million to Funds Flow. We continue to expect our hedging program to provide Funds Flow protection during 2016. Subsequent to the quarter, we added downside protection on 6,000 bbls/day and 35,000 Mcf/day of our 2017 oil and natural gas production.

RESULTS OF OPERATIONS

Production

Production for the first quarter totaled 97,860 BOE/day, exceeding our average annual guidance range of 90,000 – 94,000 BOE/day. Compared to production in the fourth quarter of 2015 of 106,905 BOE/day, production was down 8% primarily due to asset divestments, including the fourth quarter sales of non-core Canadian shallow gas properties and non-operated North Dakota properties with production of approximately 2,700 BOE/day and 1,000 BOE/day, respectively, and the first quarter 2016 sale of Canadian Deep Basin properties with production of approximately 5,400 BOE/day.

Production in the first quarter of 2016 decreased 3% from production levels of 100,855 BOE/day in the same period of 2015. The decrease in production was due to the sale of non-core properties in Canada throughout 2015 and the first quarter of 2016, which was offset by production growth of approximately 7,700 BOE/day in our Fort Berthold crude oil assets due to our ongoing development program.

As a result of the sale of certain non-core Canadian natural gas properties in the fourth quarter of 2015 and the sale of our Alberta Deep Basin assets during the first quarter of 2016, our crude oil and natural gas liquids weighting increased to 46% in the first quarter of 2016 from 43% in the fourth quarter of 2015. Our crude oil and natural gas liquids production remains in line with our annual average guidance range of 43,000 – 45,000 BOE/day.

Average daily production volumes for the three months ended March 31, 2016 and 2015 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2016**	**2015**	**% Change**
Crude oil (bbls/day)	39,508	39,355	0%
Natural gas liquids (bbls/day)	5,494	3,735	47%
Natural gas (Mcf/day)	317,150	346,589	(8%)
Total daily sales (BOE/day)	97,860	100,855	(3%)

We are maintaining our annual average production guidance of 90,000 – 94,000 BOE/day and our liquids guidance of 43,000 – 45,000 BOE/day despite the previously announced second quarter sale of assets located in northwest Alberta with expected average 2016 production of 2,300 BOE/day. This guidance does not contemplate any additional acquisitions or divestments.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, Funds Flow and financial condition. The following table compares quarterly average prices from the first quarter of 2016 to the first quarter of 2015:

Pricing (average for the period)	**Q1 2016**	**Q4 2015**	**Q3 2015**	**Q2 2015**	**Q1 2015**
Benchmarks					
WTI crude oil (US$/bbl)	$ 33.45	$ 42.18	$ 46.43	$ 57.94	$ 48.64
AECO natural gas – monthly index (CDN$/Mcf)	2.11	2.65	2.80	2.67	2.95
AECO natural gas – daily index (CDN$/Mcf)	1.83	2.47	2.90	2.64	2.75
NYMEX natural gas – last day (US$/Mcf)	2.09	2.27	2.77	2.64	2.98
USD/CDN exchange rate	1.37	1.34	1.31	1.23	1.24
Enerplus selling price(1)					
Crude oil (CDN$/bbl)	$ 31.59	$ 43.04	$ 48.22	$ 58.26	$ 44.04
Natural gas liquids (CDN$/bbl)	11.34	16.61	13.51	20.88	22.48
Natural gas (CDN$/Mcf)	1.77	1.89	2.08	2.09	2.58
Average differentials					
MSW Edmonton – WTI (US$/bbl)	$ (3.69)	$ (2.44)	$ (3.42)	$ (3.06)	$ (6.80)
WCS Hardisty – WTI (US$/bbl)	(14.24)	(14.50)	(13.27)	(11.59)	(14.73)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.99)	(1.15)	(1.66)	(1.50)	(1.77)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(1.07)	(1.23)	(1.75)	(1.57)	(1.75)
AECO monthly – NYMEX (US$/Mcf)	(0.56)	(0.28)	(0.63)	(0.47)	(0.60)
Enerplus realized differentials(1)					
Canada crude oil – WTI (US$/bbl)	$ (14.14)	$ (13.63)	$ (11.82)	$ (12.50)	$ (15.22)
Canada natural gas – NYMEX (US$/Mcf)	(0.63)	(0.42)	(0.43)	(0.46)	(0.46)
Bakken crude oil – WTI (US$/bbl)	(8.38)	(7.93)	(8.52)	(9.30)	(11.65)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.91)	(1.13)	(1.64)	(1.39)	(1.32)

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

CRUDE OIL AND NATURAL GAS LIQUIDS

Our realized crude oil price averaged $31.59/bbl in the first quarter, 27% lower than the previous quarter. WTI crude oil prices fell by 21% versus the previous quarter as seasonal refinery outages combined with continued oversupply drove U.S. oil inventories to near-maximum levels. This supply imbalance pushed WTI prices to a low of US$26.05/bbl in February before improving by the end of the quarter as refinery demand returned and there were growing indications of supply declines in North America and elsewhere. Modestly weaker crude oil differentials in both Canada and the U.S. also contributed to the weakness in realized oil prices during the quarter.

Our realized price for natural gas liquids fell by 32% to average $11.34/bbl in the first quarter. This was in line with benchmark prices for Canadian liquids, which fell by an average of 29% due to weaker crude oil prices and the continued oversupply of propane in North America.

NATURAL GAS

Our realized natural gas price averaged $1.77/Mcf in the first quarter, 6% lower than the fourth quarter of 2015. NYMEX prices fell by 8% and AECO monthly prices fell by approximately 20% compared to the previous quarter. Both markets remained weak in response to continued high production with lower than normal seasonal demand that resulted in significant storage surpluses across North America relative to the first quarter of 2015.

Our overall realized natural gas price outperformed changes in NYMEX and AECO prices due to improving differentials in the Marcellus. Weaker NYMEX prices narrowed Marcellus benchmark differentials, resulting in monthly Tennessee Gas Pipeline Zone 4 – 300 Leg and Transco Leidy prices averaging approximately US$1.03/Mcf below NYMEX. Our Marcellus realized price differential averaged US$0.91/Mcf below NYMEX, a 19% improvement from the previous quarter. We continue to expect our realized Marcellus differentials in 2016 to improve relative to recent years due to reduced industry spend and the continued build out of regional take-away capacity.

FOREIGN EXCHANGE

The Canadian dollar was volatile throughout the first quarter, nearing a thirteen year low of 1.46 USD/CDN mid-January before rebounding following the Bank of Canada's decision to keep interest rates unchanged. The foreign exchange rate averaged 1.37 USD/CDN during the quarter and was 1.30 USD/CDN at March 31, 2016. The majority of our oil and natural 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. Because we report in Canadian dollars, the fluctuations in the Canadian dollar also impact our U.S. dollar denominated costs, capital spending and the reported value of our U.S. dollar denominated debt.

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. Since our 2015 annual report, we have added floor protection on a portion of our oil and natural gas production for 2017.

As of May 2, 2016, we have hedged approximately 9,500 bbls/day of our expected net crude oil production for the remainder of 2016 through a combination of swaps and collars, which represents approximately 31% of our 2016 forecasted net crude oil production, after royalties. For the second quarter of 2016 we have hedged approximately 12,700 bbls/day, which represents approximately 41% of our 2016 forecasted net crude oil production, after royalties. For the second half of 2016 we have hedged 8,000 bbls/day, which represents approximately 26% of our 2016 forecasted net crude oil production, after royalties. We have also initiated our 2017 hedging program, with three way collars on 6,000 bbls/day. Price protection levels are shown in the table below. When WTI prices settle below the sold put strike price in any given month, the three way collars provide protection of approximately US$14/bbl and US$12/bbl above WTI index prices in 2016 and 2017, respectively. Overall, we expect our crude oil related hedge contracts to protect a significant portion of our Funds Flow during 2016.

As of May 2, 2016, we have downside protection on approximately 69,500 Mcf/day of our expected net natural gas production for the remainder of 2016 consisting of a combination of NYMEX swaps and collars. This represents approximately 31% of our 2016 forecasted natural gas production, after royalties. We have also initiated a 2017 hedging program, with 35,000 Mcf/day hedged to date using three way collars. Price protection levels are shown in the table below. When NYMEX prices settle below the sold put strike price in any given month, the three way collars provide protection of approximately US$0.50/Mcf and US$0.67/Mcf above NYMEX index prices in 2016 and 2017, respectively.

The following is a summary of our financial contracts in place at May 2, 2016, expressed as a percentage of our anticipated net 2016 and 2017 production volumes:

	WTI Crude Oil (US$/bbl)[1]			NYMEX Natural Gas (US$/Mcf)[1]		
	Apr 1, 2016 – Jun 30, 2016	Jul 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Dec 31, 2017	Apr 1, 2016 – Oct 31, 2016	Nov 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Dec 31, 2017
Sold Swaps	$ 64.28	–	–	$ 2.53	$ 2.48	–
%	10%	–	–	23%	11%	–
Three Way Collars						
Sold Puts	$ 50.13	$ 49.78	$ 35.67	$ 2.50	$ 2.50	$ 2.00
%	26%	26%	20%	11%	11%	16%
Purchased Puts	$ 64.38	$ 63.98	$ 48.18	$ 3.00	$ 3.00	$ 2.67
%	26%	26%	20%	11%	11%	16%
Sold Calls	$ 79.38	$ 79.63	$ 60.00	$ 3.75	$ 3.75	$ 3.32
%	26%	26%	20%	11%	11%	16%
Collars						
Sold Puts	$ 41.75	–	–	–	–	–
%	5%	–	–	–	–	–
Purchased Puts	$ 33.41	–	–	–	–	–
%	5%	–	–	–	–	–

(1) Based on weighted average price (before premiums), assumed average annual production of 92,000 BOE/day for 2016 and 2017 less royalties and production taxes of 23.0% in aggregate.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	Three months ended March 31,	
($ millions)	2016	2015
Cash gains/(losses):		
Crude oil	$ 36.6	$ 70.6
Natural gas	3.0	16.2
Total cash gains/(losses)	$ 39.6	$ 86.8
Non-cash gains/(losses):		
Change in fair value – crude oil	$ (31.2)	$ (36.0)
Change in fair value – natural gas	5.1	(0.4)
Total non-cash gains/(losses)	$ (26.1)	$ (36.4)
Total gains/(losses)	$ 13.5	$ 50.4

	Three months ended March 31,	
(Per BOE)	2016	2015
Total cash gains/(losses)	$ 4.45	$ 9.56
Total non-cash gains/(losses)	(2.94)	(4.01)
Total gains/(losses)	$ 1.51	$ 5.55

During the first quarter of 2016 we realized cash gains of $36.6 million on our crude oil contracts and $3.0 million on our natural gas contracts. In comparison, during the first quarter of 2015 we realized cash gains of $70.6 million on our crude oil contracts and $16.2 million on our natural gas contracts. The cash gains in 2016 and 2015 were due to contracts which provided floor protection above market prices.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At the end of the first quarter of 2016, the fair value of our crude oil and natural gas contracts represented net gain positions of $36.1 million and $9.2 million, respectively. The change in the fair value of our crude oil and natural gas contracts during the first quarter of 2016 represented losses of $31.2 million and gains of $5.1 million, respectively.

Revenues

($ millions)	Three months ended March 31, 2016	2015
Oil and natural gas sales	$ 170.5	$ 244.1
Royalties	(27.8)	(39.1)
Oil and natural gas sales, net of royalties	$ 142.7	$ 205.0

Oil and natural gas revenues were $170.5 million in the first quarter of 2016, a decrease of 30% or $73.6 million compared to the same period in 2015. The decrease in revenue was a result of the decline in oil and natural gas prices over the period, along with a decrease in natural gas production due to asset divestments.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended March 31, 2016	2015
Royalties	$ 27.8	$ 39.1
Per BOE	$ 3.12	$ 4.31
Production taxes	$ 7.4	$ 10.8
Per BOE	$ 0.83	$ 1.19
Royalties and production taxes	$ 35.2	$ 49.9
Per BOE	$ 3.95	$ 5.50
Royalties and production taxes (% of oil and natural gas sales, before transportation)	21%	20%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. A large percentage of our production is from U.S. properties where royalty rates are generally not as sensitive to commodity price levels. During the first quarter of 2016 royalties and production taxes decreased to $35.2 million from $49.9 million in the same quarter of 2015, primarily due to lower realized prices and lower production volumes. Royalties and production taxes averaged 21% of oil and natural gas sales before transportation costs in 2016 compared to 20% for the same period in 2015 due to increased production from U.S. properties.

We continue to expect an average royalty and production tax rate of 23% in 2016. At this time, we do not expect the recently announced Alberta modernized royalty framework to have a significant impact on our Canadian royalties when it becomes effective in 2017; however, we continue to actively monitor the changes being proposed.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended March 31, 2016	2015
Operating expenses	$ 72.6	$ 87.7
Per BOE	$ 8.15	$ 9.66

Operating expenses for the first quarter of 2016 totaled $72.6 million compared to $87.7 million for the same period in 2015. On a per BOE basis, operating expenses were $8.15/BOE, beating our annual guidance of $9.50/BOE and a 16% reduction from the same period in 2015. The decrease compared to the first quarter of 2015 was a result of successful cost saving initiatives, less repairs and maintenance due to favourable winter conditions and the divestment of Canadian properties with higher operating costs throughout 2015.

Based on our cost savings to date, a stronger Canadian dollar and the recently announced divestment of our higher cost northwest Alberta assets, we are reducing our 2016 guidance for operating expenses to $8.50/BOE from $9.50/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended March 31, 2016	2015
Transportation costs	$ 25.7	$ 26.5
Per BOE	$ 2.89	$ 2.92

For the three months ended March 31, 2016, transportation costs were $25.7 million or $2.89/BOE compared to $26.5 million or $2.92/BOE for the same period in 2015.

As a result of the impact of a stronger Canadian dollar on our U.S. dollar denominated transportation costs, we are revising our annual 2016 transportation cost guidance to $3.10/BOE from $3.30/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.

	Three months ended March 31, 2016		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	48,280 BOE/day	297,480 Mcfe/day	97,860 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 27.54	$ 1.83	$ 19.14
Royalties and production taxes	(6.43)	(0.26)	(3.95)
Cash operating expenses	(10.17)	(1.02)	(8.12)
Transportation costs	(1.87)	(0.65)	(2.89)
Netback before hedging	$ 9.07	$ (0.10)	$ 4.18
Cash gains/(losses)	8.32	0.11	4.45
Netback after hedging	$ 17.39	$ 0.01	$ 8.63
Netback before hedging ($ millions)	$ 39.9	$ (2.6)	$ 37.3
Netback after hedging ($ millions)	$ 76.5	$ 0.4	$ 76.9

	Three months ended March 31, 2015		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	44,758 BOE/day	336,582 Mcfe/day	100,855 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 38.99	$ 2.87	$ 26.89
Royalties and production taxes	(9.71)	(0.36)	(5.50)
Cash operating expenses	(13.45)	(1.08)	(9.56)
Transportation costs	(1.98)	(0.60)	(2.92)
Netback before hedging	$ 13.85	$ 0.83	$ 8.91
Cash gains/(losses)	17.52	0.54	9.56
Netback after hedging	$ 31.37	$ 1.37	$ 18.47
Netback before hedging ($ millions)	$ 55.8	$ 25.1	$ 80.9
Netback after hedging ($ millions)	$ 126.4	$ 41.3	$ 167.7

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

Crude oil and natural gas netbacks per BOE decreased during the first quarter of 2016 compared to the same period in 2015 as a result of a significant decline in commodity prices. Realized cash hedging gains helped to offset the impact of lower prices.

General and Administrative 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 (see Note 14 to the Interim Financial Statements for further details).

	Three months ended March 31,	
($ millions)	2016	2015
Cash:		
G&A expense	$ 18.4	$ 21.4
Share-based compensation	0.7	7.3
Non-Cash:		
Share-based compensation	3.4	5.0
Equity swap gain	(0.1)	(1.6)
Total G&A expenses	$ 22.4	$ 32.1

	Three months ended March 31,	
(Per BOE)	2016	2015
Cash:		
G&A expense	$ 2.07	$ 2.36
Share-based compensation	0.08	0.80
Non-Cash:		
Share-based compensation	0.39	0.55
Equity swap gain	(0.02)	(0.18)
Total G&A expenses	$ 2.52	$ 3.53

Cash G&A expenses during the first quarter of 2016 were $18.4 million ($2.07/BOE), beating guidance of $2.10/BOE and lower than $21.4 million ($2.36/BOE) in the first quarter of 2015. The decrease in cash G&A was primarily due to the reduction in staff levels of approximately 20% throughout 2015, offset by additional one-time severance payments during the first quarter of 2016 as we continued to adjust staffing levels in response to a challenging commodity price environment.

Cash SBC expense was $0.7 million ($0.08/BOE) in the first quarter of 2016 compared to $7.3 million ($0.80/BOE) during same period in 2015 as we settled the final grants of our cash-settled Restricted Share Unit ("RSU") plans. The Director Share Unit ("DSU") plan is our only remaining cash-settled LTI plan.

We recorded non-cash SBC of $3.4 million ($0.39/BOE) in the first quarter of 2016 compared to $5.0 million ($0.55/BOE) during the same period in 2015. The decrease in non-cash SBC over the same period in 2015 was due to reduced staff levels and a decrease in our 2016 treasury-settled SBC grant as a result of current economic conditions.

We previously hedged a portion of the outstanding cash settled grants under our LTI plans. As a result of the increase in our share price since year end, we recorded a non-cash mark-to-market gain of $0.1 million on these hedges during the first quarter of 2016. As of March 31, 2016, we had 470,000 units hedged at a weighted average price of $16.89/share.

Based on staff reductions and our continued focus on cost control, we are reducing our 2016 guidance for cash G&A expenses to $2.00/BOE from $2.10/BOE.

Interest Expense

($ millions)	Three months ended March 31, 2016	2015
Interest on senior notes and bank facility	$ 14.5	$ 16.8
Non-cash interest expense	0.2	0.2
Total interest expense	$ 14.7	$ 17.0

We recorded total interest expense of $14.7 million during the first quarter of 2016 compared to $17.0 million for the same period in 2015. The decrease in interest expense corresponds to a decrease in the aggregate principal amount of our outstanding senior notes with higher fixed rates following our repurchase of US$172.0 million of senior notes during the first quarter. The repurchase of the senior notes was funded by both asset divestment proceeds and lower interest rate bank debt. Subsequent to the quarter, we repurchased an additional US$95 million of senior notes. In total, we have repurchased US$267 million of senior notes to date at prices ranging from 90% to par value. As a result of these optional prepayments, we expect to save approximately US$13 million in interest expense on an annualized basis.

At March 31, 2016, approximately 85% of our debt was based on fixed interest rates and 15% on floating interest rates, with a weighted average interest rate of 4.8% and a borrowing rate of 2.5%, respectively.

Foreign Exchange

($ millions)	Three months ended March 31, 2016	2015
Realized loss/(gain)	$ 1.8	$ (35.6)
Unrealized loss/(gain)	(56.2)	139.8
Total foreign exchange loss/(gain)	$ (54.4)	$ 104.2
USD/CDN exchange rate	1.37	1.24

We recorded a net foreign exchange gain of $54.4 million during the first quarter of 2016 compared to a loss of $104.2 million for the same period in 2015. Realized losses of $1.8 million recorded during the first quarter of 2016 related to day-to-day transactions recorded in foreign currencies. During the first quarter of 2015, we realized a foreign exchange gain of $35.6 million primarily as a result of a $39.9 million gain on the unwind of certain foreign exchange swaps.

Unrealized foreign exchange gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. At March 31, 2016, the Canadian dollar strengthened relative to the U.S. dollar compared to December 31, 2015, resulting in unrealized gains of $56.2 million. See Note 12 to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended March 31, 2016	2015
Capital spending	$ 43.3	$ 167.0
Office capital	–	0.9
Sub-total	43.3	167.9
Property and land acquisitions	$ 3.6	$ (0.2)
Property divestments	(187.8)	(3.7)
Sub-total	(184.2)	(3.9)
Total	$ (140.9)	$ 164.0

Capital spending for the first quarter of 2016 totaled $43.3 million compared to $167.0 million during the same period in 2015. Despite our reduced capital spending we continued to invest modestly in our core areas, with spending of $19.8 million on our Fort Berthold crude oil properties, $19.1 million on our Canadian crude properties and $3.5 million on our Marcellus assets.

During the first quarter of 2016, we completed several property divestments for combined proceeds of $187.8 million, net of closing costs, including the sale of certain Canadian Deep Basin properties located in Alberta with production of approximately 5,400 BOE/day. During the first quarter of 2015, property divestments totaled $3.7 million and consisted of minor non-core undeveloped lands.

Subsequent to the quarter, we entered into an agreement to sell certain non-core properties located in northwest Alberta, including our Pouce Coupe assets, for proceeds of approximately $95.5 million, subject to closing costs, and with estimated 2016 production of approximately 2,300 BOE/day. We expect the sale to close during the second quarter. Including this divestment, we expect year to date divestment proceeds of approximately $283.3 million.

We continue to expect annual capital spending of $200 million.

Gain on Asset Sales and Note Repurchases

We recorded a gain of $145.1 million on the sale of certain oil and natural gas properties during the first quarter of 2016. We expect to record an additional gain of approximately $70 million on the previously announced second quarter sale of non-core properties in northwest Alberta, bringing our year to date gain on asset divestments to approximately $215 million. Under full cost accounting rules, divestitures of oil and natural gas properties are generally accounted for as adjustments to the full cost pool with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would significantly alter the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized. Gains and losses are evaluated on a case by case basis for each asset sale, and future sales may or may not result in such treatment.

During the first quarter of 2016, we recorded a gain of $7.1 million on the repurchase of US$172 million of outstanding senior notes at a discount to par value. Subsequent to the quarter, we repurchased an additional US$95 million of senior notes at a price of 90% of par value, which we expect to result in a gain of approximately $12 million during the second quarter.

Depletion, Depreciation and Accretion ("DD&A")

	Three months ended March 31,	
($ millions, except per BOE amounts)	2016	2015
DD&A expense	$ 91.2	$ 132.4
Per BOE	$ 10.24	$ 14.58

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2016, DD&A was $91.2 million compared to $132.4 million for the same period in 2015. The decrease is primarily due to the cumulative effect of impairments recorded during 2015.

Impairment

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country basis using estimated after-tax future net cash flows discounted at 10 percent 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 reversed in future periods.

The trailing twelve month average crude oil and natural gas prices decreased significantly during 2015 and into the first quarter of 2016 resulting in non-cash impairments. For the three months ended March 31, 2016, we recorded an impairment of $46.2 million in the U.S. cost centre compared to $267.6 in the same period of 2015. No impairment was recorded to the Canadian cost centre in the first quarter of 2016 or 2015.

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. For the remainder of this year, the primary factors include future first-day-of-the-month commodity prices, reserves revisions, our capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. We expect the twelve month trailing prices to decline further during 2016, impacting the ceiling value and resulting in further non-cash impairments. See Note 5 to the Interim Financial Statements for trailing twelve month prices.

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 based on our net ownership interest and management's estimate of 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 $197.2 million at March 31, 2016, compared to $206.4 million at December 31, 2015. During the first quarter of 2016, asset retirement obligation settlements were $2.5 million and asset retirement obligations removed due to divestments were $10.0 million compared to $3.9 million and nil, respectively, for the same period in 2015. As a result of divestments year to date, including the previously announced second quarter sale of certain non-core assets in northwest Alberta, we expect to reduce our asset retirement obligation by $22.7 million or 12%. See Note 8 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended March 31,	
($ millions)	**2016**	**2015**
Current tax expense/(recovery)	$ (0.2)	$ 0.1
Deferred tax expense/(recovery)	256.5	(138.4)
Total tax expense/(recovery)	$ 256.3	$ (138.3)

We recorded a total tax expense of $256.3 million during the first quarter of 2016 compared to a $138.3 million total tax recovery for the same period in 2015. The current quarter expense includes an additional valuation allowance of $258.5 million recorded against our deferred income tax asset. The recovery in the first quarter of 2015 is due to a non-cash asset impairment expense recorded in the U.S. cost centre. We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not that all or a portion of our deferred income tax assets will be realized. Our assessment is primarily based on a projection of undiscounted future taxable income using historical trailing twelve months benchmark prices. After recording the valuation allowance, our overall net deferred income tax asset was $237.1 million at March 31, 2016 (December 31, 2015 – $516.1 million).

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 under our bank credit facility and senior notes, 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 March 31, 2016, our senior debt to EBITDA ratio was 1.6x and our Debt to Funds Flow Ratio was 2.3x. Although it is not included in our debt covenants, the Debt to Funds Flow Ratio is often used by investors and analysts to evaluate our liquidity.

We have continued to be diligent in managing and preserving our financial position in 2016. Our non-core asset divestment program continued to provide significant liquidity, with proceeds of $187.8 million during the first quarter and total proceeds of approximately $283 million to date, including the previously announced second quarter sale of non-core Canadian assets. These proceeds, along with our largely undrawn bank credit facility, were used to fund the repurchase of US$172 million of our senior notes during the quarter, and a total of US$267 million of senior notes to date. The repurchases were completed at prices ranging from 90% to par value, resulting in a total gain of $19 million. These gains, combined with year to date gains on asset sales of approximately $215 million, are expected to meaningfully improve our 2016 EBITDA. Furthermore, as a result of replacing fixed term, higher interest rate senior notes with lower interest rate bank debt and using divestment proceeds to repay outstanding debt, we expect to save approximately US$13 million in interest expense on an annualized basis. Utilizing a portion of our bank credit facility in place of the senior notes provides additional flexibility within our capital structure to reduce our leverage further as cash becomes available.

At March 31, 2016, total debt net of cash was $992.8 million, comprised of $149.6 million of bank indebtedness and $844.5 million of senior notes less $1.3 million in cash, compared to $1,216.2 million at December 31, 2015, comprised of $86.5 million of bank indebtedness and $1,137.1 million of senior notes less $7.5 million in cash. At March 31, 2016, we were approximately 19% drawn on our $800 million bank credit facility.

In addition to our non-core asset divestment program and debt management strategy, we continued to maintain our financial flexibility through an ongoing focus on cost efficiencies, disciplined capital spending and our previously announced reduction in monthly dividends to $0.01 per share, effective with our April 2016 payment. Our Adjusted Payout Ratio, which is calculated as cash dividends plus capital and office expenditures divided by Funds Flow, was 138% in the first quarter of 2016, compared to 197% for the same period in 2015. After adjusting for net acquisition and divestment proceeds, we had a funding surplus of $168.1 million, which we used to reduce our outstanding debt.

Our working capital deficiency, excluding cash and current deferred assets and liabilities, decreased to $85.2 million at March 31, 2016 from $104.0 million at December 31, 2015. We expect to finance our working capital deficit and our ongoing working capital requirements through Funds Flow and our bank credit facility. Furthermore, we have sufficient liquidity to meet our financial commitments, as disclosed under "Commitments" in the Annual MD&A.

At March 31, 2016, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Based on our current guidance, we expect to manage our business within these financial ratios; however, current oil and gas prices have created a significant level of uncertainty which may challenge the assumptions and estimates used in Management's forecast. If we exceed any of the covenants, we may be required to repay, refinance or renegotiate the terms of the debt. If we reach or exceed these covenant thresholds, there are a number of steps that may be taken to improve them, including asset divestments, a reduction to capital spending and equity issuances.

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 March 31, 2016:

Covenant Description		March 31, 2016
Bank Credit Facility:	**Maximum Ratio**	
Senior Debt to EBITDA	3.5 x	1.6 x
Total Debt to EBITDA	4.0 x	1.6 x
Total Debt to Capitalization	50%	36%
Senior Notes:	**Maximum Ratio**	
Senior Debt to EBITDA[1]	3.0 x – 3.5 x	1.6 x
Maximum debt to consolidated present value of total proved reserves[2]	60%	43%
	Minimum Ratio	
EBITDA to Interest	4.0 x	9.6 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 March 31, 2016 were $208.1 million and $613.7 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) 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.
(2) Maximum debt to consolidated present value of total proved reserves is calculated annually on December 31 based on before tax reserves at forecast prices discounted at 10%.

Dividends

	Three months ended March 31,	
($ millions, except per share amounts)	2016	2015
Dividends to shareholders	$ 14.5	$ 47.4
Per weighted average share (Basic)	$ 0.07	$ 0.23

We reported a total of $14.5 million or $0.07 per share in dividends to our shareholders in the first quarter of 2016 compared to $47.4 million or $0.23 per share in the first quarter of 2015.

Effective with the April 2016 payment, we reduced the monthly dividend by 67% from $0.03 per share to $0.01 per share to provide additional financial flexibility and to balance Funds Flow with capital and dividends. 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

	Three months ended March 31,	
	2016	2015
Share capital ($ millions)	$ 3,142.9	$ 3,125.9
Common shares outstanding (thousands)	207,133	206,179
Weighted average shares outstanding – basic (thousands)	206,716	205,845
Weighted average shares outstanding – diluted (thousands)	206,716	205,845

During the first quarter of 2016 a total 594,000 shares and $9.4 million of additional equity was issued pursuant to the treasury-settled RSU plan. In comparison, during the first quarter of 2015 a total of 447,000 shares and $5.7 million of additional equity was issued pursuant to the stock option plan and the treasury settled RSU plan. For further details see Note 14 to the Interim Financial Statements.

At March 31, 2016 and May 5, 2016 we had 207,133,000 shares outstanding (2015 – 206,179,000).

SELECTED QUARTERLY CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended March 31, 2016			Three months ended March 31, 2015		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	14,186	25,322	39,508	16,973	22,382	39,355
Natural gas liquids (bbls/day)	1,804	3,690	5,494	2,359	1,376	3,735
Natural gas (Mcf/day)	99,539	217,611	317,150	135,419	211,170	346,589
Total average daily production (BOE/day)	32,580	65,280	97,860	41,902	58,953	100,855
Pricing[2]						
Crude oil (per bbl)	$ 26.55	$ 34.42	$ 31.59	$ 41.47	$ 45.99	$ 44.04
Natural gas liquids (per bbl)	24.98	4.68	11.34	29.14	11.06	22.48
Natural gas (per Mcf)	2.01	1.66	1.77	3.13	2.22	2.58
Capital Expenditures						
Capital spending	$ 19.1	$ 24.2	$ 43.3	$ 76.9	$ 90.1	$ 167.0
Acquisitions	1.0	2.6	3.6	1.2	(1.4)	(0.2)
Divestments	(188.3)	0.5	(187.8)	(1.0)	(2.7)	(3.7)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 56.7	$ 113.8	$ 170.5	$ 107.9	$ 136.2	$ 244.1
Royalties	(5.4)	(22.4)	(27.8)	(12.4)	(26.7)	(39.1)
Production taxes	(0.8)	(6.6)	(7.4)	(1.8)	(9.0)	(10.8)
Cash operating expenses	(43.5)	(28.8)	(72.3)	(57.0)	(29.8)	(86.8)
Transportation costs	(3.6)	(22.1)	(25.7)	(6.2)	(20.3)	(26.5)
Netback before hedging	$ 3.4	$ 33.9	$ 37.3	$ 30.5	$ 50.4	$ 80.9
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (13.5)	$ –	$ (13.5)	$ (50.4)	$ –	$ (50.4)
General and administrative expense[4]	18.3	4.1	22.4	23.5	8.6	32.1
Current income tax expense/(recovery)	(0.3)	0.1	(0.2)	–	0.1	0.1

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See "Non-GAAP Measures" section in this MD&A.
(4) 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	Net Income/(Loss) Per Share Diluted
2016				
First Quarter	$ 142.7	$ (173.7)	$ (0.84)	$ (0.84)
2015				
Fourth Quarter	$ 199.4	$ (625.0)	$ (3.03)	$ (3.03)
Third Quarter	228.3	(292.7)	(1.42)	(1.42)
Second Quarter	251.7	(312.5)	(1.52)	(1.52)
First Quarter	205.0	(293.2)	(1.42)	(1.42)
Total 2015	$ 884.4	$ (1,523.4)	$ (7.39)	$ (7.39)
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

Oil and gas sales, net of royalties, decreased in the first quarter of 2016 due to lower realized commodity prices and a decrease in natural gas production compared to the fourth quarter of 2015. Oil and gas sales, net of royalties, increased during the first and second quarters of 2014 until realized commodity prices began to decline significantly in the third quarter. During 2015, the impact of weak commodity prices was somewhat offset by increasing production. Net losses reported in 2016 and 2015 were primarily due to asset impairments related to the decrease in the trailing twelve month average commodity prices, along with reduced revenues.

2016 UPDATED GUIDANCE

As a result of our continued focus on cost savings, the strengthening Canadian dollar and the divestment of higher operating cost properties, we have reduced our operating expense, transportation cost and cash G&A expense guidance by a total of $1.30/BOE, combined. All other guidance has been maintained and is summarized below. This guidance includes the previously announced second quarter sale of non-core assets located in northwest Alberta, but does not include any further unannounced acquisitions or divestments.

Summary of 2016 Expectations	Target
Capital spending	$200 million
Average annual production	90,000 – 94,000 BOE/day
Crude oil and natural gas liquids volumes	43,000 – 45,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	23%
Operating expenses	$8.50/BOE (from $9.50/BOE)
Transportation costs	$3.10/BOE (from $3.30/BOE)
Cash G&A expenses	$2.00/BOE (from $2.10/BOE)

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at March 31, 2016, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on January 1, 2016 and ended March 31, 2016 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 2016 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 funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management programs in 2016 and in the future; 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 2016 and its impact on our production level and land holdings; potential future asset and goodwill impairments, as well as the relevant factors that may affect such 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 the time at which we may pay 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; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes, and to negotiate relief if required; our future acquisitions and dispositions, expected timing thereof, production and reductions in asset retirement obligations associated therewith and use of proceeds therefrom; expected gains for accounting purposes in respect to our repurchase of senior notes and our asset divestments; anticipated amount of interest expense savings in respect to our repurchase of senior notes; 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 curtailment of production and/or reduced realized prices; current commodity price, differentials 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 contingent 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; our ability to negotiate debt covenant relief under our bank credit facility and outstanding senior notes if required; the availability of third party services; and the extent of our liabilities. In addition, our 2016 guidance contained in this MD&A is based on the following: a WTI price of US$42.38/bbl, a NYMEX price of US$2.28/Mcf, an AECO price of $1.72/GJ and a USD/CDN exchange rate of 1.29. 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: continued low commodity prices environment or 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; 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; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent 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; 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 the annual MD&A and in our other public filings).

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

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	March 31, 2016	December 31, 2015
Assets			
Current assets			
Cash		$ 1,281	$ 7,498
Accounts receivable	3	107,840	132,156
Deferred financial assets	15	45,276	71,438
Other current assets		6,441	9,953
		160,838	221,045
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	985,065	1,166,587
Other capital assets, net	4	17,083	19,686
Property, plant and equipment		1,002,148	1,186,273
Goodwill		644,852	657,831
Deferred income tax asset	13	237,076	516,085
Total Assets		$ 2,044,914	$ 2,581,234
Liabilities			
Current liabilities			
Accounts payable	6	$ 197,372	$ 239,950
Dividends payable		2,071	6,196
Deferred financial liabilities	15	5,648	4,100
		205,091	250,246
Deferred financial liabilities	15	1,818	3,193
Long-term debt	7	994,118	1,223,682
Asset retirement obligation	8	197,202	206,359
		1,193,138	1,433,234
Total Liabilities		1,398,229	1,683,480
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value Issued and outstanding: March 31, 2016 – 207.1 million shares December 31, 2015 – 206.5 million shares	14	3,142,931	3,133,524
Paid-in capital		50,198	56,176
Accumulated deficit		(2,882,748)	(2,694,618)
Accumulated other comprehensive income/(loss)		336,304	402,672
		646,685	897,754
Total Liabilities & Equity		$ 2,044,914	$ 2,581,234
Contingencies	16		
Subsequent events	18		

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

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

Three months ended March 31 (CDN$ thousands) unaudited	**Note**	**2016**	**2015**
Revenues			
Oil and natural gas sales, net of royalties	9	$ 142,661	$ 204,960
Commodity derivative instruments gain/(loss)	15	13,464	50,398
		156,125	255,358
Expenses			
Operating		72,590	87,727
Transportation		25,718	26,483
Production taxes		7,436	10,813
General and administrative	10	22,453	32,080
Depletion, depreciation and accretion		91,161	132,350
Asset impairment	5	46,177	267,611
Interest	11	14,716	17,033
Foreign exchange (gain)/loss	12	(54,408)	104,202
Gain on divestment of assets	4	(145,100)	–
Gain on prepayment of senior notes	7	(7,118)	–
Other expense/(income)		(160)	8,612
		73,465	686,911
Income/(Loss) before taxes		82,660	(431,553)
Current income tax expense/(recovery)	13	(159)	63
Deferred income tax expense/(recovery)	13	256,485	(138,410)
Net Income/(Loss)		$ (173,666)	$ (293,206)
Other Comprehensive Income/(Loss)			
Change in cumulative translation adjustment		(66,368)	176,759
Other Comprehensive Income/(Loss)		(66,368)	176,759
Total Comprehensive Income/(Loss)		$ (240,034)	$ (116,447)
Net Income/(Loss) per Share			
Basic	14	$ (0.84)	$ (1.42)
Diluted	14	$ (0.84)	$ (1.42)

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Condensed Consolidated Statements of Changes in Shareholders' Equity

Three months ended March 31 (CDN$ thousands) unaudited	**2016**	**2015**
Share Capital		
Balance, beginning of year	$ 3,133,524	$ 3,120,002
Stock Option Plan – cash	–	2,571
Share-based compensation – settled	9,407	3,095
Stock Option Plan – exercised	–	227
Balance, end of period	$ 3,142,931	$ 3,125,895
Paid-in Capital		
Balance, beginning of year	$ 56,176	$ 46,906
Share-based compensation – settled	(9,407)	(3,095)
Stock Option Plan – exercised	–	(227)
Share-based compensation – non-cash	3,429	4,970
Balance, end of period	$ 50,198	$ 48,554
Accumulated Deficit		
Balance, beginning of year	$ (2,694,618)	$ (1,039,260)
Net income/(loss)	(173,666)	(293,206)
Dividends	(14,464)	(47,359)
Balance, end of period	$ (2,882,748)	$ (1,379,825)
Accumulated Other Comprehensive Income/(Loss)		
Balance, beginning of year	$ 402,672	$ 95,478
Change in cumulative translation adjustment	(66,368)	176,759
Balance, end of period	$ 336,304	$ 272,237
Total Shareholders' Equity	$ 646,685	$ 2,066,861

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Condensed Consolidated Statements of Cash Flows

Three months ended March 31 (CDN$ thousands) unaudited	**Note**	**2016**	**2015**
Operating Activities			
Net income/(loss)		$ (173,666)	$ (293,206)
Non-cash items add/(deduct):			
Depletion, depreciation and accretion		91,161	132,350
Asset impairment	5	46,177	267,611
Changes in fair value of derivative instruments	15	26,335	87,499
Deferred income tax expense/(recovery)	13	256,485	(138,410)
Foreign exchange (gain)/loss on debt and working capital	12	(56,158)	88,014
Share-based compensation	14	3,429	4,970
Amortization of debt issue costs		182	240
Gain on divestment of assets		(145,100)	–
Gain on prepayment of senior notes		(7,118)	–
Derivative settlement of foreign exchange swaps		–	(39,904)
Asset retirement obligation expenditures	8	(2,454)	(3,890)
Changes in non-cash operating working capital	17	30,474	25,822
Cash flow from operating activities		69,747	131,096
Financing Activities			
Proceeds from the issuance of shares	14	–	2,571
Cash dividends	14	(14,464)	(47,359)
Increase/(decrease) in bank credit facility		70,849	45,820
Proceeds/(repayment) of senior notes	7	(226,029)	–
Derivative settlement of foreign exchange swaps		–	39,904
Changes in non-cash financing working capital		(4,125)	(8,207)
Cash flow from/(used in) financing activities		(173,769)	32,729
Investing Activities			
Capital expenditures and office expenditures		(43,292)	(167,888)
Property and land acquisitions		(3,554)	236
Property divestments		187,768	3,712
Changes in non-cash investing working capital		(42,125)	931
Cash flow from/(used in) investing activities		98,797	(163,009)
Effect of exchange rate changes on cash		(992)	(249)
Change in cash		(6,217)	567
Cash, beginning of period		7,498	2,036
Cash, end of period		$ 1,281	$ 2,603

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Notes to Condensed Consolidated Financial Statements

(unaudited)

1) REPORTING ENTITY

These interim Condensed Consolidated Financial Statements ("interim Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation ("The Company" or "Enerplus") including its Canadian and U.S. subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada. The interim Consolidated Financial Statements were authorized for issue by the Board of Directors on May 5, 2016.

2) BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under accounting principles generally accepted in the United States of America ("U.S. GAAP") for the three months ended March 31, 2016, and the 2015 comparative periods. Certain information and notes normally included with the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2015. 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, 2015.

These unaudited interim Consolidated Financial Statements reflect, in the opinion of Management, all normal and recurring adjustments necessary to present fairly the financial position and results of the Company as at and for the periods presented.

3) ACCOUNTS RECEIVABLE

($ thousands)	March 31, 2016	December 31, 2015
Accrued receivables	$ 72,321	$ 91,378
Accounts receivable – trade	19,937	22,615
Current income tax receivable	18,786	21,410
Allowance for doubtful accounts	(3,204)	(3,247)
Total accounts receivable	$ 107,840	$ 132,156

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

As at March 31, 2016 ($ thousands)	**Cost**	**Accumulated Depletion, Depreciation, and Impairment**	**Net Book Value**
Oil and natural gas properties	$ 13,168,213	$ 12,183,148	$ 985,065
Other capital assets	104,020	86,937	17,083
Total PP&E	$ 13,272,233	$ 12,270,085	$ 1,002,148

As at December 31, 2015 ($ thousands)	**Cost**	**Accumulated Depletion, Depreciation, and Impairment**	**Net Book Value**
Oil and natural gas properties	$ 13,541,670	$ 12,375,083	$ 1,166,587
Other capital assets	105,124	85,438	19,686
Total PP&E	$ 13,646,794	$ 12,460,521	$ 1,186,273

During the three months ended March 31, 2016, Enerplus disposed of certain Canadian properties for proceeds of $181.8 million, which resulted in a gain on disposition of $145.1 million (2015 – nil).

Under full cost accounting rules, divestitures of oil and gas properties are generally accounted for as adjustments to capitalized costs, with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would have otherwise significantly altered the relationship between a cost center's capitalized costs and proved reserves, then a gain or loss must be recognized.

5) ASSET IMPAIRMENT

	Three months ended March 31,	
($ thousands)	2016	2015
Oil and natural gas properties:		
Canada cost centre	$ –	$ –
U.S. cost centre	46,177	267,611
Impairment expense	$ 46,177	$ 267,611

For the three months ended March 31, 2016 non-cash impairment of $46.2 million was recorded in the United States cost centre due to lower 12-month average trailing crude oil prices (2015 – $267.6 million). No impairments were recorded to the Canada cost centre for the periods ended March 31, 2016 and 2015.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from March 31, 2015 through March 31, 2016:

Period	WTI Crude Oil US$/bbl	Exchange Rate US/CDN	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	AECO Natural Gas Spot CDN$/Mcf
Q1 2016	$ 46.26	1.32	$ 56.97	$ 2.41	$ 2.47
Q4 2015	50.28	1.27	59.38	2.58	2.69
Q3 2015	59.21	1.22	66.51	3.08	3.00
Q2 2015	71.75	1.16	75.83	3.42	3.33
Q1 2015	82.73	1.14	84.61	3.88	3.86

6) ACCOUNTS PAYABLE

($ thousands)	March 31, 2016	December 31, 2015
Accrued payables	$ 119,653	$ 167,253
Accounts payable – trade	77,719	72,697
Total accounts payable	$ 197,372	$ 239,950

7) DEBT

($ thousands)	March 31, 2016	December 31, 2015
Current	$ –	$ –
	–	–
Long-term:		
Bank credit facility	$ 149,599	$ 86,543
Senior notes	844,519	1,137,139
	994,118	1,223,682
Total debt	$ 994,118	$ 1,223,682

For the period ended March 31, 2016 Enerplus repurchased US$172 million in outstanding senior notes at a discount, resulting in a gain of $7.1 million, for a total payment of $226.0 million. Subsequent to March 31, 2016, an additional US$95 million in senior notes were repurchased at a discount and it is expected that an additional gain of $12 million will be recorded.

8) ASSET RETIREMENT OBLIGATION

Enerplus has estimated the present value of its asset retirement obligation to be $197.2 million at March 31, 2016 compared to $206.4 million at December 31, 2015, based on a total undiscounted liability of $506.0 million and $556.4 million, respectively. The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.92% (December 31, 2015 – 5.91%).

($ thousands)	Three months ended March 31, 2016	Year ended December 31, 2015
Balance, beginning of year	$ 206,359	$ 288,692
Change in estimate	169	(35,386)
Property acquisition and development activity	153	761
Divestments	(9,974)	(48,748)
Settlements	(2,454)	(14,935)
Accretion expense	2,949	15,975
Balance, end of period	$ 197,202	$ 206,359

9) OIL AND NATURAL GAS SALES

	Three months ended March 31,	
($ thousands)	2016	2015
Oil and natural gas sales	$ 170,423	$ 244,077
Royalties(1)	(27,762)	(39,117)
Oil and natural gas sales, net of royalties	$ 142,661	$ 204,960

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

10) GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended March 31,	
($ thousands)	2016	2015
General and administrative expense	$ 18,426	$ 21,435
Share-based compensation expense	4,027	10,645
General and administrative expense	$ 22,453	$ 32,080

11) INTEREST EXPENSE

	Three months ended March 31,	
($ thousands)	2016	2015
Realized:		
Interest on bank debt and senior notes	$ 14,534	$ 16,793
Unrealized:		
Amortization of debt issue costs	182	240
Interest expense	$ 14,716	$ 17,033

12) FOREIGN EXCHANGE

($ thousands)	Three months ended March 31, 2016	2015
Realized:		
Foreign exchange (gain)/loss	$ 1,750	$ (35,574)
Unrealized:		
Translation of U.S. dollar debt and working capital (gain)/loss	(56,158)	88,014
Foreign exchange derivatives (gain)/loss	–	51,762
Foreign exchange (gain)/loss	$ (54,408)	$ 104,202

13) INCOME TAXES

Enerplus' provision for income tax is a follows:

($ thousands)	Three months ended March 31, 2016	2015
Current tax expense/(recovery)		
Canada	$ (303)	$ –
United States	144	63
Current tax expense/(recovery)	(159)	63
Deferred Tax expense/(recovery)		
Canada	$ 12,846	$ (9,263)
United States	243,639	(129,147)
Deferred tax expense/(recovery)	256,485	(138,410)
Income tax expense/(recovery)	$ 256,326	$ (138,347)

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, recognition of valuation allowance, foreign rate differentials for foreign operations, statutory and other rate differentials, the reversal or recognition of previously recognized or unrecognized deferred tax assets, non-taxable portions of capital gains and losses, and non-deductible share-based compensation. Enerplus recorded an additional valuation allowance of $258.5 million in the quarter. For the year ended December 31, 2015, a total valuation allowance of $443.7 million was recognized, with most of it being recorded in the fourth quarter.

14) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized unlimited number of common shares Issued: (thousands)	Three months ended March 31, 2016 Shares	Amount	Year ended December 31, 2015 Shares	Amount
Balance, beginning of year	206,539	$ 3,133,524	205,732	$ 3,120,002
Issued for cash:				
Stock Option Plan	–	–	234	3,205
Non-cash:				
Share-based compensation – settled	594	9,407	573	10,050
Stock Option Plan – exercised	–	–	–	267
Balance, end of period	207,133	$ 3,142,931	206,539	$ 3,133,524

Dividends declared to shareholders for the three months ended March 31, 2016 were $14.5 million (2015 – $47.4 million).

b) Share-based compensation

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

($ thousands)	Three months ended March 31, 2016	2015
Cash:		
Long-term incentive plans expense	$ 733	$ 7,274
Non-Cash:		
Long-term incentive plans expense	3,429	4,970
Equity swap (gain)/loss	(135)	(1,599)
Share-based compensation expense	$ 4,027	$ 10,645

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

In 2014, the Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") plans were amended such that grants under the plans are settled through the issuance of treasury shares. The amendment was effective beginning with the grant in March of 2014. The final cash-settled PSU and RSU grants were settled in December, 2015 and March, 2016, respectively.

The following table summarizes the PSU, RSU and Director Share Unit ("DSU") activity for the three months ended March 31, 2016:

For the three months ended March 31, 2016 (thousands of units)	Cash-settled LTI plans RSU	DSU	Equity-settled LTI Plans PSU	RSU	Total
Balance, beginning of year	92	166	1,222	1,627	3,107
Granted	–	134	1,406	1,971	3,511
Vested	(89)	–	–	(594)	(683)
Forfeited	(3)	–	(86)	(79)	(168)
Balance, end of period	–	300	2,542	2,925	5,767

Cash-settled LTI Plans

For three months ended March 31, 2016 the Company recorded cash share-based compensation expense of $0.7 million (2015 – $7.3 million). For the three months ended March 31, 2016, the Company made cash payments of $2.7 million related to its cash-settled plans (2015 – $5.6 million).

Enerplus continues to grant DSUs through cash-settled awards. As of March 31, 2016, a liability of $1.8 million (2015 – $3.1 million) has been recorded to Accounts Payable on the Consolidated Balance Sheets.

Equity-settled LTI Plans

For the three months ended March 31, 2016 the Company recorded non-cash share-based compensation expense of $3.4 million (2015 – $5.0 million).

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

At March 31, 2016 ($ thousands, except for years)	**PSU(1)**	**RSU**	**Total**
Cumulative recognized share-based compensation expense	$ 5,378	$ 9,852	$ 15,230
Unrecognized share-based compensation expense	8,851	12,200	21,051
Fair value	$ 14,229	$ 22,052	$ 36,281
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 for the three months ended March 31, 2016. At March 31, 2016 all stock options are fully vested and any related non-cash share-based compensation expense has been fully recognized.

The following table summarizes the stock option plan activity for the period ended March 31, 2016:

Period ended March 31, 2016	**Number of Options** (thousands)	**Weighted Average Exercise Price**
Options outstanding, beginning of year	7,580	$ 18.49
Forfeited	(632)	19.00
Options outstanding, end of period	6,948	$ 18.45
Options exercisable, end of period	6,948	$ 18.45

At March 31, 2016, 6,948,000 options were exercisable at a weighted average reduced exercise price of $18.45 with a weighted average remaining contractual term of 3.3 years, giving an aggregate intrinsic value of nil (2015 – nil). The intrinsic value of options exercised for the period ended March 31, 2016 was nil (2015 – $0.1 million).

c) Basic and Diluted Net Income/(Loss) Per Share

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

	Three months ended March 31,	
(thousands, except per share amounts)	**2016**	**2015**
Net income/(loss)	$ (173,666)	$ (293,206)
Weighted average shares outstanding – Basic	206,716	205,845
Dilutive impact of share-based compensation(1)	–	–
Weighted average shares outstanding – Diluted	206,716	205,845
Net income/(loss) per share		
Basic	$ (0.84)	$ (1.42)
Diluted(1)	$ (0.84)	$ (1.42)

(1) For the three months ended March 31, 2016 and 2015 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 March 31, 2016, 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 March 31, 2016 senior notes included in long-term debt had a carrying value of $844.5 million and a fair value of $911.4 million (December 31, 2015 – $1,137.2 million and $1,220.8 million, respectively).

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

b) Derivative Financial Instruments

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

The following table summarizes the change in fair value for the three months ended March 31, 2016 and 2015:

Gain/(Loss) ($ thousands)	March 31, 2016	March 31, 2015	Income Statement Presentation
Foreign Exchange Derivatives	$ –	$ (51,762)	Foreign exchange
Electricity Swaps	(308)	(927)	Operating expense
Equity Swaps	135	1,599	General and administrative expense
Commodity Derivative Instruments:			
Oil	(31,276)	(35,959)	Commodity derivative instruments
Gas	5,114	(450)	
Total Unrealized Gain/(Loss)	$ (26,335)	$ (87,499)	

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

	Three months ended March 31,	
($ thousands)	2016	2015
Change in fair value gain/(loss)	$ (26,162)	$ (36,409)
Net realized cash gain/(loss)	39,626	86,807
Commodity derivative instruments gain/(loss)	$ 13,464	$ 50,398

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

	March 31, 2016			December 31, 2015		
	Assets	Liabilities		Assets	Liabilities	
($ thousands)	Current	Current	Long-term	Current	Current	Long-term
Electricity Swaps	$ –	$ 2,084	$ –	$ –	$ 1,776	$ –
Equity Swaps	–	3,564	1,818	–	2,324	3,193
Commodity Derivative Instruments:						
Oil	36,121	–	–	67,397	–	–
Gas	9,155	–	–	4,041	–	–
Total	$ 45,276	$ 5,648	$ 1,818	$ 71,438	$ 4,100	$ 3,193

c) Risk Management

In the normal course of operations, Enerplus is exposed to various market risks, including commodity prices, foreign exchange, interest rates and equity prices, credit risk and liquidity risk.

(i) Market Risk

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

Commodity Price Risk:

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

The following tables summarize Enerplus' price risk management positions at May 2, 2016:

Crude Oil Instruments:

Instrument Type[1]	bbls/day	US$/bbl
April 1, 2016 – April 30, 2016		
WTI Swap	3,000	64.28
WTI Purchased Put	11,000	55.82
WTI Sold Call	11,000	68.64
WTI Sold Put	8,000	50.13
WCS Differential Swap	3,000	(14.03)
MSW Differential Swap	1,000	(3.50)
May 1, 2016 – May 31, 2016		
WTI Swap	3,000	64.28
WTI Purchased Put	10,000	58.30
WTI Sold Call	10,000	72.36
WTI Sold Put	8,000	50.13
WCS Differential Swap	3,000	(14.03)
MSW Differential Swap	1,000	(3.50)
Jun 1, 2016 – Jun 30, 2016		
WTI Swap	3,000	64.28
WTI Purchased Put	8,000	64.38
WTI Sold Call	8,000	79.38
WTI Sold Put	8,000	50.13
WCS Differential Swap	3,000	(14.03)
MSW Differential Swap	1,000	(3.50)
Jul 1, 2016 – Dec 31, 2016		
WTI Purchased Put	8,000	63.98
WTI Sold Call	8,000	79.63
WTI Sold Put	8,000	49.78
WCS Differential Swap	3,000	(14.03)
MSW Differential Swap	1,000	(3.50)
Jan 1, 2017 – Dec 31, 2017		
WTI Purchased Put	6,000	48.18
WTI Sold Call	6,000	60.00
WTI Sold Put	6,000	35.67

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

Natural Gas Instruments:

Instrument Type[1]	MMcf/day	US$/Mcf
Apr 1, 2016 – Oct 31, 2016		
NYMEX Swap	50.0	2.53
NYMEX Purchased Put	25.0	3.00
NYMEX Sold Put	25.0	2.50
NYMEX Sold Call	25.0	3.75
Nov 1, 2016 – Dec 31, 2016		
NYMEX Swap	25.0	2.48
NYMEX Purchased Put	25.0	3.00
NYMEX Sold Put	25.0	2.50
NYMEX Sold Call	25.0	3.75
Jan 1, 2017 – Dec 31, 2017		
NYMEX Purchased Put	35.0	2.67
NYMEX Sold Put	35.0	2.00
NYMEX Sold Call	35.0	3.32

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

Electricity Instruments:

Instrument Type	MWh	CDN$/MWh
Apr 1, 2016 – Dec 31, 2016		
AESO Power Swap[1]	15.0	46.60
Jan 1, 2017 – Dec 31, 2017		
AESO Power Swap[1]	6.0	44.38

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

Physical Contracts:

Instrument Type	MMcf/day	US$/Mcf
Apr 1, 2016 – Oct 31, 2016 AECO-NYMEX Basis	21.4	(0.68)
Nov 1, 2016 – Oct 31, 2017 AECO-NYMEX Basis	80.0	(0.65)
Nov 1, 2017 – Oct 31, 2018 AECO-NYMEX Basis	80.0	(0.65)
Nov 1, 2018 – Oct 31, 2019 AECO-NYMEX Basis	80.0	(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. To mitigate exposure to fluctuations in foreign exchange, Enerplus may enter into foreign exchange derivatives. At March 31, 2016 Enerplus did not have any foreign exchange derivatives outstanding.

Interest Rate Risk:

At March 31, 2016, approximately 85% of Enerplus' debt was based on fixed interest rates and 15% was based on floating interest rates. To mitigate exposure to fluctuation in floating market interest rates, Enerplus may enter into interest rate derivatives. At March 31, 2016 Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 14. Enerplus has entered into various equity swaps maturing between 2016 and 2018 and has effectively fixed the future settlement cost on 470,000 shares at a weighted average price of $16.89 per share.

(ii) Credit Risk

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

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

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At March 31, 2016 approximately 62% of Enerplus' marketing receivables were with companies considered investment grade (December 31, 2015 – 61%).

At March 31, 2016 approximately $2.6 million or 2% of Enerplus' total accounts receivable were aged over 120 days and considered past due (December 31, 2015 – $2.6 million and 2%). The majority of these accounts are due from various joint venture partners. Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at March 31, 2016 was $3.2 million (December 31, 2015 – $3.2 million).

(iii) Liquidity Risk & Capital Management

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

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

At March 31, 2016, Enerplus was in full compliance with all covenants under the bank credit facility and outstanding senior notes.

16) CONTINGENCIES

Enerplus is subject to various legal claims and actions arising in the normal course of business. Although the outcome of such claims and actions cannot be predicted with certainty, the Company does not expect these matters to have a material impact on the 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.

17) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	Three months ended, March 31, 2016	Three months ended, March 31, 2015
Accounts receivable	$ 61,077	$ 47,966
Other current assets	3,331	(4,798)
Accounts payable	(33,934)	(17,346)
	$ 30,474	$ 25,822

b) Other

($ thousands)	Three months ended, March 31, 2016	Three months ended, March 31, 2015
Income taxes paid/(received)	$ (1,924)	$ (19,344)
Interest paid	$ 9,806	$ 6,482

18) SUBSEQUENT EVENTS

Subsequent to March 31, 2016, Enerplus entered into an agreement to sell non-core assets in Northwest Alberta for proceeds of approximately $95.5 million, before closing adjustments. A gain of approximately $70 million is expected to be recognized on this transaction.

Subsequent to March 31, 2016, Enerplus repurchased US$95 million in senior notes at a discount, and it is expected that an additional gain on repurchase will be recorded.

BOARD OF DIRECTORS

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

David H. Barr[9][12]
Corporate Director
The Woodlands, Texas

Michael R. Culbert[3][5][9]
President & CEO
Progress Energy Canada Ltd.
Calgary, Alberta

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

Hilary A. Foulkes[5][7][9][11]
Corporate Director
Calgary, Alberta

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

Susan M. MacKenzie[7][10][11]
Corporate Director
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

Jodine J. Jenson Labrie
Senior Vice President & Chief Financial Officer

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

Nathan D. Fisher
Vice President, U.S. Development & Geosciences

Daniel J. Fitzgerald
Vice President, Business Development

John E. Hoffman
Vice President, Canadian Operations

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

Edward L. McLaughlin
President, U.S. Operations

Lisa M. Ower
Vice President, People & Culture

Shaina B. Morihira
Corporate Controller, Finance

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 Corporation is a responsible developer of high quality crude oil and natural gas assets in Canada and the United States, focused on providing both growth and income to its shareholders.

ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE

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

Toll Free 1.800.319.6462
investorrelations@enerplus.com

enerPLUS

www.enerplus.com