Q1 2015

enerPLUS

FIRST QUARTER REPORT
THREE MONTHS ENDED MARCH 31, 2015

SELECTED FINANCIAL RESULTS	Three months ended March 31, 2015	2014
Financial (000's)		
Funds Flow	$ 109,164	$ 220,512
Cash and Stock Dividends	47,359	54,935
Net Income/(Loss)	(293,206)	40,037
Debt Outstanding – net of cash	1,272,204	1,020,720
Capital Spending	167,011	217,763
Property and Land Acquisitions	(236)	9,969
Property Divestments	3,712	117,225
Debt to Trailing 12-Month Funds Flow	1.7x	1.3x
Financial per Weighted Average Shares Outstanding		
Funds Flow	$ 0.53	$ 1.09
Net Income/(Loss) (Basic)	(1.42)	0.20
Weighted Average Number of Shares Outstanding (000's)	205,845	203,178
Selected Financial Results per BOE(1)(2)		
Oil & Natural Gas Sales(3)	$ 26.89	$ 55.66
Royalties and Production Taxes	(5.50)	(12.05)
Commodity Derivative Instruments	9.56	(1.72)
Cash Operating Expenses	(9.56)	(8.97)
Transportation Costs	(2.92)	(2.51)
General and Administrative	(2.36)	(2.31)
Share Based Compensation	(0.80)	(0.77)
Interest, Foreign Exchange and Other Expenses	(3.28)	(1.67)
Taxes	–	(0.87)
Funds Flow	$ 12.03	$ 24.79

SELECTED OPERATING RESULTS	Three months ended March 31, 2015	2014
Average Daily Production(2)		
Crude oil (bbls/day)	39,355	37,760
NGLs (bbls/day)	3,735	3,262
Natural gas (Mcf/day)	346,589	346,794
Total (BOE/day)	100,855	98,821
% Crude Oil & Natural Gas Liquids	43%	42%
Average Selling Price(2)(3)		
Crude oil (per bbl)	$ 44.04	$ 93.04
NGLs (per bbl)	22.48	67.90
Natural gas (per Mcf)	2.58	5.07
Net Wells drilled	28	30

(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.

Average Benchmark Pricing	Three months ended March 31, 2015	2014
WTI crude oil (US$/bbl)	$ 48.64	$ 98.68
AECO – monthly index (CDN$/Mcf)	2.95	4.76
AECO – daily index (CDN$/Mcf)	2.75	5.71
NYMEX – last day (US$/Mcf)	2.98	4.94
USD/CDN exchange rate	1.24	1.10

Share Trading Summary For the three months ended March 31, 2015	CDN* – ERF (CDN$)	U.S.** – ERF (US$)
High	$ 14.53	$ 11.73
Low	$ 9.41	$ 7.89
Close	$ 12.84	$ 10.14

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

2015 Dividends per Share	CDN$	US$(1)
January	$ 0.09	$ 0.08
February	$ 0.09	$ 0.07
March	$ 0.09	$ 0.07
First Quarter Total	$ 0.27	$ 0.22

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

PRESIDENT'S MESSAGE

I am pleased to report we delivered another quarter of consistent and strong operating results. We continued to demonstrate prudent financial stewardship through a focus on disciplined capital allocation and cost control. These efforts have resulted in lower capital spending and improvements in our operating and administrative costs relative to our expectations. We are well positioned to achieve our key operating targets in 2015 and remain in a strong financial position as we navigate through a challenging commodity price environment.

Production averaged approximately 100,900 BOE per day during the quarter. Crude oil and natural gas liquids accounted for 43% of first quarter volumes, which was in line with our expectations. Production is down 4% quarter-over-quarter in response to reduced capital spending and deferred activity. Of note, we delayed virtually all well completion activity in North Dakota from December until the end of February in response to low oil prices and cost uncertainty at the time. With prices stabilizing and improved cost structures, we plan to accelerate second quarter well completions in North Dakota and re-establish growth in the region. Given the solid momentum going into the second quarter, in part based upon strong well performance in North Dakota, we are well positioned to achieve our annual average production guidance of 93,000 – 100,000 BOE per day and liquids guidance of 42 – 44% despite the previously announced sale of non-core oil producing assets.

Significant declines in commodity prices resulted in first quarter funds flow of $109 million compared to $213 million in the fourth quarter of 2014. The West Texas Intermediate benchmark price for crude oil averaged US$48.64 per barrel during the quarter, down from approximately US$73 per barrel during the previous quarter. AECO and NYMEX gas prices were sharply lower quarter-over-quarter, both falling by 26%. Although supported by our strong commodity hedge position, funds flow over the quarter was impacted by one-time charges of $11 million and realized losses on our foreign exchange revenue hedges of $8.6 million. Funds flow was also impacted by our decision to delay completion activity in North Dakota until late February.

Our capital spending during the quarter was $167 million and remains on track with our full year capital program. We directed the majority of capital to our North Dakota, Wilrich and Canadian crude oil properties. In total, we drilled 27.9 net wells and brought 17.4 net wells on-stream across our portfolio in the first quarter.

Both our operating and G&A costs came in under expectations during the quarter at $11.03 per BOE and $2.36 per BOE respectively. Operating costs excluding Marcellus gathering fees were $9.66 per BOE during the quarter. Further information on our treatment of Marcellus gathering fees is provided in Management's Discussion and Analysis.

We incurred a non-cash asset impairment charge in the quarter of $268 million. Under U.S. GAAP we are required to use twelve month trailing average prices to determine impairment and consequently the impairment reflects the low oil prices in the fourth quarter of 2014 and the first quarter of 2015.

Our focus on cost efficiencies, the deferral of activity and our strong hedge position continue to help preserve our financial flexibility for 2015. We ended the quarter with a debt-to-trailing-twelve-month funds flow ratio of 1.7 times, up from 1.3 times at year-end 2014. We reduced our dividend by 44% to $0.05 per share effective with the April payment as we believe this is a more appropriate level in the context of current commodity prices. Subsequent to the quarter, our previously announced non-core asset sales closed generating proceeds of $186 million. These proceeds were used to repay the debt outstanding on our $1 billion bank credit facility, which is essentially undrawn following these divestments.

Production and Capital Spending

	Three months ended March 31, 2015	
	Average Production Volumes	**Capital Spending** ($ millions)
Crude Oil & NGLs (bbls/day)		
Canada	19,332	57
United States	23,758	79
Total Crude Oil & NGLs (bbls/day)	43,090	136
Natural Gas (Mcf/day)		
Canada	135,419	20
United States	211,170	11
Total Natural Gas (Mcf/day)	346,589	31
Company Total (BOE/day)	100,855	167

Net Drilling Activity* –** for the three months ended March 31, 2015

	Horizontal Wells Drilled	Wells Pending Completion/Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Crude Oil				
Canada	14.4	9.0	10.9	–
United States	8.2	7.3	3.6	–
Total Crude Oil	**22.6**	**16.3**	**14.5**	**–**
Natural Gas				
Canada	3.0	3.0	–	–
United States	2.2	2.2	2.9	–
Total Natural Gas	**5.2**	**5.2**	**2.9**	**–**
Company Total	**27.9**	**21.5**	**17.4**	**–**

* Wells drilled during the quarter that are pending potential completion/tie-in or abandonment as at March 31, 2015.
** Total wells brought on-stream during the quarter regardless of when they were drilled.
*** Table may not add due to rounding.

Asset Activity

We had some notable operational successes during the quarter. At Fort Berthold, we continue to evolve our completion design with strong results. Despite no operated on-stream activity for most of the quarter, we brought a 4-well pad on-stream at the end of February with initial 30 day average production rates (IP30) per well ranging from 1,290 – 1,390 barrels of oil per day. Additionally, one of our most recent Three Forks wells, located in the southeast area of our acreage, is significantly outperforming our expectations for that region with an IP30 rate of approximately 1,250 barrels of oil per day. In all, we drilled 8.2 net wells with 3.6 net wells brought on-stream over the quarter for a total investment of $79 million. Average daily production during the quarter was 26,500 BOE per day from both Fort Berthold and Sleeping Giant. We are seeing cost reductions materialize with well costs trending down close to 15% from 2014 levels. Our average well cost in Fort Berthold year-to-date is approximately US$11.5 million.

With drilling activity outpacing completions at Fort Berthold, we continued to build an inventory of drilled uncompleted wells which stood at 18.8 net wells at quarter-end. As completion activity begins to increase in the second quarter in response to prices stabilizing and improved cost structures, we will start to work through some of this uncompleted well inventory. We expect to re-establish production growth in North Dakota in the second quarter. We are also evaluating an increase in the number of planned completions in the second half of 2015.

In the Marcellus, capital spending was meaningfully lower in the quarter at $11 million, compared to $26 million during the previous quarter. Drilling activity slowed as we moved to a one-rig drilling program with 2.2 net wells drilled and 2.9 net wells brought on-stream. We continued to curtail production due to weak natural gas prices in the region and expect to continue curtailing production for the remainder of the year. Production during the quarter averaged 195 MMcf per day.

In our Canadian oil portfolio, we drilled 14.4 net wells with 10.9 net wells brought on-stream. The drilling activity was largely focused at Brooks, targeting the Lower Mannville sands. Average well results have been in line with our expectations and we are targeting growth of approximately 1,350 BOE per day during 2015, resulting in expected annual average production of approximately 3,900 BOE per day from the Brooks area. The timing of the Brooks drilling program was driven by lease retention.

In the Deep Basin, our operated 3 horizontal well pad was drilled and completed at Ansell. Initial production rates in late March showed encouraging results. The wells were completed under budget and initial production results support our assessment of a sweet spot trend across Enerplus' lands.

Crude Oil & Natural Gas Pricing

The West Texas Intermediate benchmark price for crude oil fell more than 30% quarter-over-quarter and over 50% from the first quarter of 2014. Both Canadian heavy and light oil differentials were slightly weaker, while the Bakken crude oil differential improved from the fourth quarter. Our average realized sales price for crude oil during the quarter was down approximately 36% from the fourth quarter to $44.04 per barrel. The outlook ahead on crude differentials is positive. Improved market access, particularly to the U.S. Gulf Coast, has reduced the downside impact mid-continent refinery outages have historically had on Canadian prices. Reduced supply from oil sands producers due to seasonal maintenance is expected to further strengthen Canadian crude oil differentials in the second quarter. The narrowing of the Bakken crude differential is a result of increased rail capacity coming into service during the quarter. The reversal of Enbridge's Line 9, scheduled for the second quarter of 2015, is expected to provide further support for U.S. Bakken differentials in the coming months.

On the natural gas side, both AECO and NYMEX fell sharply as a result of strong production in the U.S. combined with a delay in winter weather in key regions in the U.S. which allowed storage to return to more seasonally average levels compared to this time last year. Our realized sales price for natural gas was $2.58 per Mcf during the quarter, down approximately 21% from the previous quarter. In the Marcellus, our realized differential was US$1.32 per Mcf below NYMEX, compared to the average regional spot differential of US$1.68 per Mcf. Approximately 46% of our Marcellus production is sold under long-term sales contracts which have exposure to markets outside of Northeast Pennsylvania.

Our commodity hedge position continues to help support funds flow in 2015. Approximately 35% of our expected crude oil production net of royalties from April through December is hedged at over US$90 per barrel and approximately 46% of anticipated natural gas volumes net of royalties are hedged at US$3.92 per Mcf over the same period.

We have established an initial crude oil hedge position for 2016. Approximately 26% of our forecasted 2016 crude oil production net of royalties, is hedged with 6,000 barrels per day protected through 3-way collars (US$50 per barrel by US$65 per barrel by $US80 per barrel), and an additional 2,000 barrels per day swapped at US$65.50 per barrel.

Board & Executive Changes

I would like to thank Mr. Edwin Dodge who is retiring and not standing for re-election as a Board member this year. Ed joined the Board of Directors of Enerplus in May 2004 and his guidance and direction have helped to successfully grow and transition the business over the past 11 years.

I would also like to thank Mr. Donald Nelson who is not standing for re-election as a Board member this year. Don joined the Board of Directors of Enerplus in June 2012 and has provided valuable insight and guidance during his time as a Director.

I am pleased to announce that John Hoffman has joined the executive team of Enerplus in the position of Vice-President of Canadian Operations. John brings a wealth of experience to the role having spent 25 years in the Canadian energy industry in both leadership and engineering roles, focused largely in the Western Canadian Sedimentary Basin.

Outlook

Despite the current commodity price environment, Enerplus is well positioned. We remain committed to disciplined capital allocation with a strong focus on cost control. We continue to achieve excellent results from our asset base with strong momentum continuing into the second quarter. We are also seeing encouraging signs in the market with a modest recovery in crude oil prices and costs continuing to trend down. As we look to re-establish production growth in our North Dakota properties, we are well positioned to achieve our annual average production guidance range for the year. Supported by our commodity hedging program and commitment to reducing costs and driving operational efficiencies, we expect to remain in a position of strength through 2015.

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 7, 2015 and is to be read in conjunction with:

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

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" below for further information.

BASIS OF PRESENTATION

The Interim Financial Statements and notes have been prepared in accordance with U.S. GAAP including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified and all 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. The term netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating costs and transportation.

Calculation of Netback ($ millions)	**Three months ended March 31, 2015**	**2014**
Oil and natural gas sales	$ 244.1	$ 495.0
Less:		
Royalties	(39.1)	(87.3)
Production taxes	(10.8)	(19.9)
Cash operating costs[1]	(86.8)	(79.8)
Transportation	(26.5)	(22.3)
Netback before hedging	$ 80.9	$ 285.7
Cash gains/(losses) on derivative instruments	86.8	(15.3)
Netback after hedging	$ 167.7	$ 270.4

(1) Operating costs adjusted to exclude non-cash losses on fixed price electricity swaps of $0.9 million in the three months ended March 31, 2015 and $0.1 million in the three months ended March 31, 2014.

"Funds Flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. Funds flow is calculated as net cash provided by operating activities 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, 2015**	**2014**
Cash flow from operating activities	$ 131.1	$ 140.4
Asset retirement obligation expenditures	3.9	4.3
Changes in non-cash operating working capital	(25.8)	75.8
Funds flow	$ 109.2	$ 220.5

"Debt to Funds Flow Ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The debt to funds flow ratio is calculated as total debt net of cash divided by a trailing 12 months of funds flow. This measure is not equivalent to Debt to EBITDA and is not used by Enerplus to determine compliance with financial covenants.

"Adjusted Payout Ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. We calculate our adjusted payout ratio as cash dividends plus capital and office expenditures divided by funds flow.

Calculation of Adjusted Payout Ratio ($ millions)	**Three months ended March 31, 2015**	**2014**
Cash dividends[1]	$ 47.4	$ 42.1
Capital and office expenditures	167.9	218.2
	$ 215.3	$ 260.3
Funds flow	109.2	220.5
Adjusted payout ratio (%)	197%	118%

(1) Cash dividends exclude Stock Dividend Plan proceeds in 2014.

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "Senior Debt to EBITDA", "Total Debt to EBITDA", "Total Debt to Capitalization, "maximum debt to consolidated present value of total proven reserves" and "EBITDA to Interest" and are used to determine the Company's compliance with financial covenants under its bank credit facility and outstanding senior notes. Calculation of such terms is described under the "Liquidity and Capital Resources" section of this MD&A.

OVERVIEW

Our strong operational performance continued during the first quarter of 2015 as we focused on execution under a disciplined capital program. We met or exceeded all guidance targets and exited the quarter with a strong balance sheet.

Average daily production for the first quarter was 100,855 BOE/day, exceeding our guidance range of 93,000 – 100,000 BOE/day. Production was slightly lower compared to the fourth quarter of 2014 as we delayed North Dakota completions in response to low oil prices and cost uncertainties. We expect to re-establish growth in North Dakota in the second quarter as prices stabilize and costs are reduced. We continued to curtail Marcellus production during the quarter with total curtailments in line with our guidance. We are well positioned to achieve our annual average production guidance of 93,000 – 100,000 BOE/day and our crude oil and liquids guidance of 42% – 44% despite the previously announced sale of non-core crude oil assets which closed subsequent to the quarter.

First quarter funds flow decreased to $109.2 million from $220.5 million in the same period in 2014 as oil and gas sales reflected the dramatic decline in commodity prices. Our commodity hedges provided protection with cash gains of $86.8 million in the first quarter compared to losses of $15.3 million in the same period in 2014. Current quarter funds flow was reduced by $11 million as a result of a number of one-time charges including severance payments, rig termination charges and retroactive royalty adjustments. In addition, we recorded cash losses of $8.6 million on our foreign exchange collars as the Canadian dollar weakened against the U.S. dollar.

We reported a net loss of $293.2 million for the quarter compared to net income of $40.0 million in the same quarter of 2014. Our first quarter earnings benefited from commodity hedging gains of $50.4 million and one-time realized foreign exchange gains of $39.9 million as we crystalized gains on US$175 million in foreign exchange swaps. These gains were offset by asset impairment charges of $267.6 million in our U.S. cost centre as a result of the use of a 12-month trailing average commodity price to determine impairment, in accordance with U.S. GAAP.

Capital spending is on track, with $167.0 million spent in the first quarter. We continue to expect to spend $480 million in 2015 with the majority of spending weighted to the first half of the year.

General and administrative costs came in slightly under guidance of $2.40/BOE at $21.4 million or $2.36/BOE for the quarter compared to $20.5 million or $2.31/BOE in the first quarter of 2014, despite the inclusion of one-time charges for severance.

Effective in 2015 we have reclassified Marcellus gathering charges from operating expenses to transportation costs. These charges pertain to pipeline costs paid to third parties to transport saleable natural gas in the Marcellus from the lease to a downstream point of sale. This is a change in presentation and does not affect our netbacks, funds flow or net income. During the first quarter of 2015, gathering costs of $12.4 million or $1.37/BOE were reclassified from operating expenses to transportation costs. We expect annual gathering fees of approximately $1.35/BOE in 2015.

Based on the reclassification of $1.35/BOE of annual gathering costs, we are revising our 2015 guidance for operating costs downwards from $11.10/BOE to $9.75/BOE. Operating expenses came in below our revised guidance, totaling $87.7 million or $9.66/BOE compared to $79.9 million or $8.98/BOE in the first quarter of 2014. Operating costs in the first quarter were $6.1 million lower compared to the fourth quarter of 2014 as we began to see cost savings materialize. We are issuing 2015 transportation guidance of $3.00/BOE compared to previous transportation of $1.65/BOE. Transportation costs for the quarter were $26.5 million or $2.92/BOE, compared to $22.3 million or $2.51/BOE for the same period in 2014. Our aggregate guidance remains unchanged.

Despite a continued decline in commodity prices during the quarter we have maintained a strong balance sheet. At March 31, 2015, we were approximately 13% drawn on our $1.0 billion credit facility and had a debt to funds flow ratio of 1.7x and Senior Debt to Earnings before Interest, Taxes, Depreciation and Amortization and other non-cash charges ("EBITDA") ratio of 1.6x. Subsequent to the quarter, we closed non-core asset sales with combined proceeds of $185.8 million, net of closing costs, and used the proceeds to repay our outstanding debt. These divestments include the previously announced sale of our Pembina waterflood assets which closed on April 15, 2015.

RESULTS OF OPERATIONS

Production

Production for the first quarter totaled 100,855 BOE/day, exceeding our guidance range of 93,000 – 100,000 BOE/day and increasing 2% compared to 98,821 BOE/day in the first quarter of 2014. This increase was driven by growth in our Fort Berthold assets, where production increased 6% year over year due to our ongoing development program. Gas production remained relatively flat compared to the first quarter of 2014, with growth of almost 10% in our Marcellus gas production offset by the divestment of non-core Canadian natural gas properties in the second half of 2014.

Compared to production in the fourth quarter of 2014 of 105,591 BOE/day, production was down 4% primarily due to decreased crude oil and liquids production in the U.S. as we delayed North Dakota completions in response to low oil prices and cost uncertainties. Natural gas production also decreased slightly, down 3% compared to the fourth quarter. We continued to curtail our Marcellus natural gas production during the quarter in line with our guidance range.

Given the decrease in our crude oil production, our crude oil and natural gas liquids weighting decreased to 43% in the first quarter of 2015 from 44% in the fourth quarter of 2014. Our crude oil and natural gas liquids production remains in line with our guidance range of 42% – 44%.

Average daily production volumes for the three months ended March 31, 2015 and 2014 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2015**	**2014**	**% Change**
Crude oil (bbls/day)	39,355	37,760	4%
Natural gas liquids (bbls/day)	3,735	3,262	15%
Natural gas (Mcf/day)	346,589	346,794	0%
Total daily sales (BOE/day)	100,855	98,821	2%

We are maintaining our annual average production guidance for 2015 of 93,000 – 100,000 BOE/day and are well positioned to achieve both our production and liquids guidance despite the sale of non-core assets with production of approximately 1,900 BOE/day that closed subsequent to the quarter. This guidance includes our previously announced divestments but 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 2015 to the first quarter of 2014:

Pricing (average for the period)	Q1 2015	Q4 2014	Q3 2014	Q2 2014	Q1 2014
Benchmarks					
WTI crude oil (US$/bbl)	$ 48.64	$ 73.15	$ 97.17	$ 102.99	$ 98.68
AECO natural gas – monthly index (CDN$/Mcf)	2.95	4.01	4.22	4.68	4.76
AECO natural gas – daily index (CDN$/Mcf)	2.75	3.60	4.02	4.69	5.71
NYMEX natural gas – last day (US$/Mcf)	2.98	4.00	4.06	4.67	4.94
US/CDN exchange rate	1.24	1.14	1.09	1.09	1.10
Enerplus selling price[1]					
Crude oil (CDN$/bbl)	$ 44.04	$ 69.17	$ 88.28	$ 96.46	$ 93.04
Natural gas liquids (CDN$/bbl)	22.48	42.34	46.76	51.80	67.90
Natural gas (CDN$/Mcf)	2.58	3.25	3.36	4.15	5.07
Average differentials					
MSW Edmonton – WTI (US$/bbl)	$ (6.80)	$ (6.36)	$ (7.93)	$ (6.13)	$ (8.25)
WCS Hardisty – WTI (US$/bbl)	(14.73)	(14.24)	(20.18)	(20.04)	(23.13)
Brent Futures (ICE) – WTI (US$/bbl)	6.58	3.85	6.26	6.75	9.19
AECO monthly – NYMEX (US$/Mcf)	(0.60)	(0.47)	(0.18)	(0.38)	(0.63)
Enerplus realized differentials[1]					
Canada crude oil – WTI (US$/bbl)	$ (15.22)	$ (12.17)	$ (20.51)	$ (16.77)	$ (20.07)
Canada natural gas – NYMEX (US$/Mcf)	(0.46)	(0.62)	(0.29)	(0.46)	(0.04)
Bakken crude oil – WTI (US$/bbl)	(11.65)	(12.15)	(12.81)	(12.81)	(9.82)
Marcellus natural gas – NYMEX (US$/Mcf)	(1.32)	(1.62)	(1.70)	(1.48)	(0.86)

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

Crude Oil and Natural Gas Liquids

WTI crude oil prices continued their decline from the previous quarter, averaging US$48.64/bbl due to global oversupply and growing inventories in the U.S., which increased by 22% from the end of 2014. Growing concerns that storage could reach maximum levels in certain regions, specifically at Cushing, Oklahoma, resulted in daily WTI prices settling at a low of US$43.46/bbl in March. WTI prices have since recovered as the threat of storage congestion in the U.S. has eased somewhat heading into the summer.

Heavy crude oil differentials in Canada weakened slightly during the quarter, with WCS averaging US$14.73/bbl below WTI, compared to US$14.24/bbl below WTI in the previous quarter. Light crude oil differentials also weakened, averaging US$6.80/bbl below WTI during the quarter, compared to US$6.36/bbl in the previous quarter. Canadian heavy oil production continued to move on rail despite higher transportation costs compared to pipelines due to existing term rail commitments made by shippers. Despite Canadian crude differentials trading wider in the quarter, the outlook ahead is positive. Improved market access, particularly to the U.S. Gulf Coast, has reduced the downside impact mid-continent refinery outages have historically had on Canadian prices. Reduced supply from oil sands producers due to seasonal maintenance is expected to further strengthen Canadian crude oil differentials in the second quarter.

In the U.S., our average realized crude oil differential was US$11.65/bbl less than WTI, an improvement of US$0.50/bbl versus the previous quarter. Strong Brent/WTI spreads improved the netback associated with oil sold to rail buyers. Increased rail capacity coming into service started to compete for production that would otherwise flow via pipeline, which caused narrowing Bakken differentials during the quarter. The reversal of Enbridge's Line 9 scheduled for the second quarter of 2015 is expected to provide support for U.S. Bakken differentials in the coming months.

Our sales price for natural gas liquids during the quarter fell by 47% compared to the fourth quarter of 2014 to average $22.48/bbl. The price received for propane decreased almost 60% versus the previous quarter due to the decline in crude oil prices as well as rapidly building inventories, with propane stocks in the U.S. almost 90% higher on average during the quarter compared to the same period last year. Additionally, the benchmark prices for butane and condensate fell by 27% and 30%, respectively, during the quarter due to the significant weakness in crude oil prices.

Natural Gas

Natural gas prices at both AECO and NYMEX were sharply lower in the quarter as strong production in the U.S. combined with a lengthy delay to winter demand in key regions in the U.S. allowed gas in storage to return to more seasonally average levels compared to this time last year. AECO monthly index prices fell by 26% versus the previous quarter to average $2.95/Mcf, while NYMEX gas prices also fell by 26% to average US$2.98/Mcf. Natural gas prices have continued to weaken throughout April as we head into a shoulder season for demand and U.S. production remains strong relative to last year.

Natural gas prices in the Marcellus also traded sharply lower in the quarter. Spot prices on the Transco Leidy pipeline averaged US$1.29/Mcf and TGP Zone 4 Marcellus daily prices averaged US$1.29/Mcf, both over 35% lower than the previous quarter. Outside of the northeast Pennsylvania producing region, prices at Dominion South Point fell by only 22% to average US$1.85/Mcf in the quarter.

With approximately 46% of our Marcellus production sold under long-term sales contracts with stronger price exposure outside of the northeast Pennsylvania producing region, our overall realized Marcellus sales price was US$1.66/Mcf. This equated to a discount to NYMEX of US$1.32/Mcf for our Marcellus production.

Foreign Exchange

During the first quarter of 2015 the Canadian dollar continued to weaken and fell 8%; the largest quarterly decline since 2008 during the credit crisis. This was due to a number of factors including the Bank of Canada's unexpected interest rate cut of 25 basis points in January, the continued decline of global oil prices, and the anticipation of increasing interest rates in the U.S. as a result of a strengthening economy. The Canadian dollar began the year at a USD/CDN exchange rate of 1.17 and weakened to 1.28 before ending the quarter at 1.27. Subsequent to the quarter end, the Canadian dollar has strengthened to 1.20 as a result of improved oil prices and a more balanced tone from the Bank of Canada. The majority of our oil and gas sales are based on U.S. dollar denominated indices and therefore a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. Because we report in Canadian dollars, the weaker Canadian dollar also increases our U.S. dollar denominated operating costs, capital spending and the interest on our U.S. dollar denominated senior notes.

Price Risk Management

We have a price risk management program that considers our overall financial position, the economics of our capital program and potential acquisitions. As of May 5, 2015, we have swapped an average of 16,841 bbls/day of crude oil from April 1, 2015 to June 30, 2015 at an average price of US$90.40/bbl, which represents approximately 54% of our forecasted crude oil production after royalties for the same period. For the second half of 2015, we have 8,000 bbls/day of crude oil swapped at an average price of US$93.86/bbl, which represents approximately 26% of our forecasted crude oil production after royalties. In relation to these swaps, we have purchased call options to participate in price upside above US$93.00/bbl on 4,000 bbls/d, and sold put options at an average strike price of US$62.23/bbl, offsetting the cost of the call premium. If actual monthly WTI prices fall below US$62.23/bbl for individual months during the remainder of 2015, our swaps on approximately 13% of our forecasted net crude oil production are effectively converted to WTI monthly index plus US$29.87/bbl, using a weighted average swap price for the year of $92.10/bbl. Additionally, we have entered into WCS differential swap positions to manage our exposure related to Canadian crude oil differentials. Overall, we expect our crude related hedge contracts to protect a significant portion of our funds flow during 2015.

For 2016, we have downside protection on 26% of our forecasted crude oil production net of royalties, with 6,000 bbls/day protected through 3 way collars (US$50/bbl by US$65/bbl by $US80/bbl), and an additional 2,000 bbls/day swapped at $65.50/bbl.

During the quarter we added modestly to our 2015 NYMEX gas hedge program. As of May 5, 2015, we are swapped on an average of 115,600 Mcf/day at an average price of US$3.92/Mcf for the remainder of 2015, representing approximately 46% of our forecasted natural gas production after royalties. In relation to the swaps, we have purchased a call spread on 5,000 Mcf/d to participate in NYMEX price upside and sold NYMEX put options on 5,000 Mcf/day at an average price of $3.25/Mcf to offset the net cost of the call spread. We do not have any gas hedging in place for 2016.

The following is a summary of our financial contracts in place at May 5, 2015, expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)[1]			NYMEX Natural Gas (US$/Mcf)[1]			
	Apr 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Dec 31, 2015	Jan 1, 2016 – Dec 31, 2016	Apr 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Sep 30, 2015	Oct 1, 2015 – Oct 31, 2015	Nov 1, 2015 – Dec 31, 2015
Downside Protection							
Sold Swaps	$ 90.40	$ 93.86	$ 65.50	$ 3.98	$ 3.83	$ 3.85	$ 4.04
%	54%	26%	7%	43%	53%	45%	37%
Purchased Puts	–	–	$ 65.00	–	–	–	–
%	–	–	19%	–	–	–	–
Upside Participation Collars							
Sold Puts	$ 62.23	$ 62.23	$ 50.00	$ 3.25	$ 3.25	$ 3.25	$ 3.25
%	13%	13%	19%	2%	2%	2%	2%
Purchased Calls	93.00	93.00	–	$ 4.29	$ 4.29	$ 4.29	$ 4.29
%	13%	13%	–	2%	2%	2%	2%
Sold Calls	–	–	$ 80.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00
%	–	–	19%	2%	2%	2%	2%

(1) Based on weighted average price (before premiums) and assumed average annual production of 93,000 – 100,000 BOE/day for 2015 and 2016, less royalties and production taxes of 21.0% in aggregate.

During 2014, we entered into foreign exchange collars to hedge a floor exchange rate on a portion of our U.S. dollar denominated oil and natural gas sales with upside participation in the event the Canadian dollar weakened. As of May 5, 2015 we have US$24 million per month hedged for 2015 at an average USD/CDN floor of 1.1088, a ceiling of 1.1845 and a conditional ceiling of 1.1263. Under these contracts, if the monthly foreign exchange rate settles above the ceiling rate the conditional ceiling is used to determine the settlement amount.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses) ($ millions)	Three months ended March 31, 2015	2014
Cash gains/(losses):		
Crude oil	$ 70.6	$ (10.7)
Natural gas	16.2	(4.6)
Total cash gains/(losses)	$ 86.8	$ (15.3)
Non-cash gains/(losses):		
Change in fair value – crude oil	$ (36.0)	$ (9.4)
Change in fair value – natural gas	(0.4)	(7.9)
Total non-cash gains/(losses)	$ (36.4)	$ (17.3)
Total gains/(losses)	$ 50.4	$ (32.6)

(Per BOE)	Three months ended March 31, 2015	2014
Total cash gains/(losses)	$ 9.56	$ (1.72)
Total non-cash gains/(losses)	(4.01)	(1.94)
Total gains/(losses)	$ 5.55	$ (3.66)

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. In comparison, during the first quarter of 2014, we realized cash losses of $10.7 million on our crude oil contracts and $4.6 million on our natural gas contracts. The cash gains in 2015 were due to contracts which provided floor protection above market prices, while cash losses in 2014 were a result of prices rising above our fixed price swap positions.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At the end of the first quarter of 2015 the fair value of our crude oil and natural gas contracts represented net gain positions of $131.2 million and $48.8 million, respectively. The change in the fair value of our crude oil and natural gas contracts during the first quarter of 2015 represented losses of $36.0 million and $0.4 million, respectively.

During the first quarter of 2015 we recorded total cash losses of $8.6 million on our foreign exchange collars and $39.9 million in cash gains on the unwind of our US$175 million in foreign exchange swaps. Unrealized foreign exchange derivative losses of $51.8 million included $27.6 million to reverse cumulative mark-to-market gains on the foreign exchange swaps and $24.2 million of mark-to-market losses on our foreign exchange collars. At March 31, 2015, the fair value of foreign exchange derivatives was a net loss of $29.9 million. See Note 15 for further information.

Revenues

	Three months ended March 31,	
($ millions)	2015	2014
Oil and natural gas sales	$ 244.1	$ 495.0
Royalties	(39.1)	(87.3)
Oil and natural gas sales, net of royalties	$ 205.0	$ 407.7

Oil and natural gas revenues were $244.1 million in the first quarter of 2015, a decrease of 51% or $250.9 million compared to the same period in 2014. The decrease in revenue was driven by the weak commodity price environment, which saw benchmark prices decline between 40% and 50% in the first quarter of 2015 compared to the same period in 2014.

Royalties and Production Taxes

	Three months ended March 31,	
($ millions, except per BOE amounts)	2015	2014
Royalties	$ 39.1	$ 87.3
Per BOE	$ 4.31	$ 9.82
Production taxes	$ 10.8	$ 19.9
Per BOE	$ 1.19	$ 2.23
Royalties and production taxes	$ 49.9	$ 107.2
Per BOE	$ 5.50	$ 12.05
Royalties and production taxes (% of oil and natural gas sales, before transportation)	20%	22%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. During the first quarter royalties and production taxes decreased to $49.9 million from $107.2 million in the same quarter of 2014, primarily due to lower realized prices. Royalties and production taxes averaged 20% of oil and gas sales before transportation in 2015 compared to 22% for the same period in 2014.

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

Operating Expenses and Transportation Costs

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

During the first quarter of 2015, Marcellus gathering fees were $12.4 million or $1.37/BOE compared to $9.2 million or $1.04/BOE during the same period of 2014.

Total operating expenses and transportation costs for the current quarter and comparative periods before and after the reclassification are provided below:

	2015 Guidance	Three months ended March 31, 2015		Three months ended March 31, 2014	
	Per BOE	$ millions	Per BOE	$ millions	Per BOE
Operating Expenses, before reclassification	$ 11.10	$ 100.1	$ 11.03	$ 89.1	$ 10.02
Gathering Fees	(1.35)	(12.4)	(1.37)	(9.2)	(1.04)
Operating Expenses, after reclassification	$ 9.75	$ 87.7	$ 9.66	$ 79.9	$ 8.98
Transportation Costs, before reclassification	$ 1.65[1]	$ 14.1	$ 1.55	$ 13.1	$ 1.47
Gathering Fees	1.35	12.4	1.37	9.2	1.04
Transportation Costs, after reclassification	$ 3.00	$ 26.5	$ 2.92	$ 22.3	$ 2.51

(1) Traditionally, we have not provided guidance for transportation costs (total costs of $1.52/BOE in 2014, before reclassification of gathering costs). After the reclassification of gathering costs, we are guiding to $3.00/BOE for 2015

Operating costs totaled $87.7 million or $9.66/BOE during the first quarter compared to $79.9 million or $8.98/BOE in the first quarter of 2014. The increase in operating costs was due the impact of a weak Canadian dollar on our U.S. operating costs along with higher well servicing and repairs and maintenance costs in the U.S.

Compared to the fourth quarter of 2014, operating costs decreased $6.1 million as we began to realize cost savings across our operations as a result of our ongoing cost control measures. These savings were offset somewhat by the weakening Canadian dollar.

Transportation costs totaled $26.5 million or $2.92/BOE, compared to $22.3 million or $2.51/BOE for the same period in 2014. Transportation expense increased over the prior year as a result of higher Marcellus gathering fees and an overall increase in U.S. transportation fees due to a weak Canadian dollar.

We are adjusting our 2015 guidance for operating costs from $11.10/BOE to $9.75/BOE and are issuing transportation guidance of $3.00/BOE from $1.65/BOE to take into account the reclassification of the Marcellus gathering fees of $1.35/BOE between the two categories. The aggregate guidance remains unchanged from the beginning of the year.

Netbacks

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

	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 costs	(13.45)	(1.08)	(9.56)
Transportation	(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

Netbacks by Property Type	Three months ended March 31, 2014 Crude Oil	Natural Gas	Total
Average Daily Production	42,307 BOE/day	339,084 Mcfe/day	98,821 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 86.23	$ 5.44	$ 55.66
Royalties and production taxes	(21.64)	(0.81)	(12.05)
Cash operating costs	(12.43)	(1.06)	(8.97)
Transportation	(1.85)	(0.48)	(2.51)
Netback before hedging	$ 50.31	$ 3.09	$ 32.13
Cash gains/(losses)	(2.80)	(0.15)	(1.72)
Netback after hedging	$ 47.51	$ 2.94	$ 30.41
Netback before hedging ($ millions)	$ 191.5	$ 94.2	$ 285.7
Netback after hedging ($ millions)	$ 180.9	$ 89.5	$ 270.4

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

Our crude oil properties accounted for 69% of our corporate netback before hedging for the first quarter of 2015 compared to 67% for the same period in 2014. Crude oil and natural gas netbacks per BOE decreased in 2015 from the same period in 2014 as a result of a significant decline in commodity prices. The impact of lower prices was partially offset by cash hedging gains.

General and Administrative ("G&A") Expenses

Total G&A expenses include cash G&A expenses as well as share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans") and our stock option plan (see Note 14 for further detail). SBC charges are dependent on our share price and can fluctuate from period to period.

($ millions)	Three months ended March 31, 2015	2014
Cash:		
G&A expense	$ 21.4	$ 20.5
Share based compensation expense	7.3	6.9
Non-Cash:		
Share based compensation expense	5.0	2.9
Equity swap loss/(gain)	(1.6)	(1.2)
Total G&A expenses	$ 32.1	$ 29.1

(Per BOE)	Three months ended March 31, 2015	2014
Cash:		
G&A expense	$ 2.36	$ 2.31
Share based compensation expense	0.80	0.77
Non-Cash:		
Share based compensation expense	0.55	0.33
Equity swap loss/(gain)	(0.18)	(0.14)
Total G&A expenses	$ 3.53	$ 3.27

Cash G&A expenses during the first quarter of 2015 were $21.4 million or $2.36/BOE, in line with guidance of $2.40/BOE and slightly higher than $20.5 million or $2.31/BOE in the first quarter of 2014. The increase in cash G&A for the first quarter was primarily due to one-time severance payments of $2.0 million.

Our share price increased by 15% during the quarter, increasing our cash and non-cash SBC to $7.3 million ($0.80/BOE) and $5.0 million ($0.55/BOE), respectively, compared to $6.9 million ($0.77/BOE) and $2.9 million ($0.33/BOE) during the same period in 2014.

We have 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 $1.6 million on these hedges during the first quarter of 2015. As of March 31, 2015 we had 630,000 units hedged at a weighted average price of $15.82/share.

We continue to expect cash G&A expenses of approximately $2.40/BOE for 2015. We do not provide guidance for SBC because it is dependent on our share price and our performance relative to our peers.

Interest Expense

	Three months ended March 31,	
($ millions)	2015	2014
Interest on senior notes and bank facility	$ 16.8	$ 14.7
Non-cash interest expense	0.2	0.5
Total interest expense	$ 17.0	$ 15.2

We recorded total interest expense of $17.0 million during the first quarter of 2015 compared to $15.2 million for the same period in 2014. The increase in interest expense corresponds to an increase in higher interest rate senior notes following our September 2014 private placement of US$200 million, the proceeds of which were used to repay our short-term bank debt. Interest expense was further increased by the impact of a weaker Canadian dollar on our U.S. dollar denominated interest payments.

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

At March 31, 2015 approximately 90% of our debt was based on fixed interest rates and 10% on floating interest rates, with weighted average interest rates of 5.3% and 2.6%, respectively.

Foreign Exchange

	Three months ended March 31,	
($ millions)	2015	2014
Realized loss/(gain)	$ (35.6)	$ 0.1
Unrealized loss/(gain)	139.8	1.4
Total foreign exchange loss/(gain)	$ 104.2	$ 1.5

We recorded a net foreign exchange loss of $104.2 million during the first quarter of 2015 compared to $1.5 million for the same period in 2014. During the quarter, we unwound our US$175 million foreign exchange swaps with terms extending to 2021 for proceeds of $39.9 million. This gain was offset by realized losses on our foreign exchange collars and day-to-day transactions denominated in foreign currencies.

We recorded unrealized losses of $51.8 million on our foreign exchange derivatives and $88.0 million on the translation of U.S. dollar debt and working capital. See Note 12 for further details.

Capital Investment

($ millions)	Three months ended March 31, 2015	2014
Capital spending	$ 167.0	$ 217.8
Office capital	0.9	0.4
Sub-total	$ 167.9	$ 218.2
Property and land acquisitions	$ (0.2)	$ 10.0
Property divestments	(3.7)	(117.2)
Sub-total	$ (3.9)	$ (107.2)
Total	$ 164.0	$ 111.0

Capital spending for the first quarter of 2015 totaled $167.0 million compared to $217.8 million during the same period in 2014. Although spending slowed in the first quarter due to continued weakness in commodity prices, we continued to invest modestly in our core areas, with spending of $78.4 million on our Fort Berthold crude oil properties, $56.8 million on our Canadian crude properties, $19.5 million on our deep gas properties in Canada and $11.3 million on our Marcellus assets.

There were no acquisitions during the first quarter of 2015, although we recorded adjustments pertaining to prior period property acquisitions. In comparison, during the first quarter of 2014 we spent $10.0 million which included the purchase of additional undeveloped land in North Dakota and Pennsylvania.

During the first quarter of 2015, we completed several minor non-core property divestments of undeveloped land for proceeds of approximately $3.7 million. During the first quarter of 2014, property divestments totaled $117.2 million which included the sale of the balance of our Montney acreage and our overriding gas royalty interest in the Jonah property in Wyoming.

Subsequent to the quarter, we completed the sales of non-core assets for combined proceeds of $185.8 million, net of closing costs, including the previously announced sale of our Pembina waterflood assets that closed on April 15, 2015.

We continue to expect annual capital spending of $480 million, with the majority of spending weighted to the first half of 2015.

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

($ millions, except per BOE amounts)	Three months ended March 31, 2015	2014
DDA&A expense	$ 132.4	$ 132.2
Per BOE	$ 14.58	$ 14.86

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2015 DDA&A was $132.4 million compared to $132.2 million for the same period in 2014.

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.

During the first quarter of 2015, trailing 12-month averages of crude oil and natural gas prices decreased significantly and resulted in a non-cash impairment of $267.6 million (before tax) being recorded in the U.S. cost centre. No impairment was recorded to the Canadian cost centre. Enerplus did not record any ceiling test impairments on its oil and natural gas properties in 2014. If commodity prices remain at levels experienced during the first quarter of 2015, the trailing twelve month prices used in the ceiling calculation will decline further and may lead to additional write downs of our oil and natural gas properties. See Note 5 for trailing 12-month prices used and further information.

Asset Retirement Obligation

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are estimated by Enerplus based on our net ownership interest, anticipated costs to abandon and reclaim and the timing of the costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation to be $295.2 million at March 31, 2015 compared to $288.7 million at December 31, 2014. See Note 8 for further information. Asset retirement obligation settlements for the first quarter totaled $3.9 million compared to $19.4 million for the same period in 2014.

Income Taxes

	Three months ended March 31,	
($ millions)	**2015**	**2014**
Current tax expense	$ 0.1	$ 7.7
Deferred tax expense/(recovery)	(138.4)	24.5
Total tax expense/(recovery)	$ (138.3)	$ 32.2

We recorded a total tax recovery of $138.3 million for the three months ended March 31, 2015 compared to a $32.2 million expense for the same period in 2014. The decrease in total tax expense is due primarily to lower income in 2015 which included a $267.6 million non-cash asset impairment expense recorded in the U.S. cost centre during the quarter.

Given the decrease in commodity prices and U.S. forecasted net income for the year, we expect current tax of less than 1% of our U.S. funds flow in 2015. As a result, our current tax expense has decreased to $0.1 million for the three months ended March 31, 2015 from $7.7 million for the same period in 2014. Our U.S. current tax is comprised mainly of Alternative Minimum Tax ("AMT") payable with respect to our U.S. subsidiary. We expect to recover any AMT paid in future years as an offset to regular U.S. income taxes otherwise payable. We do not expect to pay any cash taxes in Canada in 2015. These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisitions and divestment activity. See Note 13 for further information.

SELECTED QUARTERLY CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended March 31, 2015			Three months ended March 31, 2014		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	16,973	22,382	39,355	16,577	21,183	37,760
Natural gas liquids (bbls/day)	2,359	1,376	3,735	2,540	722	3,262
Natural gas (Mcf/day)	135,419	211,170	346,589	151,627	195,167	346,794
Total average daily production (BOE/day)	41,902	58,953	100,855	44,388	54,433	98,821
Pricing[2]						
Crude oil (per bbl)	$ 41.47	$ 45.99	$ 44.04	$ 86.74	$ 97.97	$ 93.04
Natural gas liquids (per bbl)	29.14	11.06	22.48	69.46	62.38	67.90
Natural gas (per Mcf)	3.13	2.22	2.58	5.41	4.81	5.07
Capital Expenditures						
Capital spending	$ 76.9	$ 90.1	$ 167.0	$ 127.7	$ 90.1	$ 217.8
Acquisitions	1.2	(1.4)	(0.2)	–	10.0	10.0
Divestments	(1.0)	(2.7)	(3.7)	(67.7)	(49.5)	(117.2)
Netback Before Hedging						
Oil and natural gas sales	$ 107.9	$ 136.2	$ 244.1	$ 220.0	$ 275.0	$ 495.0
Royalties	(12.4)	(26.7)	(39.1)	(34.0)	(53.3)	(87.3)
Production taxes	(1.8)	(9.0)	(10.8)	(2.0)	(17.9)	(19.9)
Cash operating expense	(57.0)	(29.8)	(86.8)	(62.1)	(17.7)	(79.8)
Transportation expense	(6.2)	(20.3)	(26.5)	(5.9)	(16.4)	(22.3)
Netback before hedging	$ 30.5	$ 50.4	$ 80.9	$ 116.0	$ 169.7	$ 285.7
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (50.4)	$ –	$ (50.4)	$ 32.6	$ –	$ 32.6
General and administrative expense[3]	23.5	8.6	32.1	23.3	5.8	29.1
Current income tax expense/(recovery)	–	0.1	0.1	(0.2)	7.9	7.7

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

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2015				
First Quarter	$ 205.0	$ (293.2)	$ (1.42)	$ (1.42)
2014				
Fourth Quarter	$ 325.3	$ 151.7	$ 0.74	$ 0.73
Third Quarter	378.3	67.4	0.33	0.32
Second Quarter	414.9	40.0	0.20	0.19
First Quarter	407.7	40.0	0.20	0.19
Total 2014	$ 1,526.2	$ 299.1	$ 1.46	$ 1.44
2013				
Fourth Quarter	$ 332.4	$ 29.6	$ 0.15	$ 0.15
Third Quarter	365.4	(3.7)	(0.02)	(0.02)
Second Quarter	341.3	38.5	0.19	0.19
First Quarter	313.4	(16.4)	(0.08)	(0.08)
Total 2013	$ 1,352.5	$ 48.0	$ 0.24	$ 0.24

Oil and gas sales decreased in the first quarter of 2015 due to lower realized commodity prices and a decrease in crude oil production compared to the fourth quarter of 2014. From the first quarter of 2013, oil and gas sales increased steadily until the third quarter of 2014 when realized commodity prices began to decline significantly. Net income in the first quarter of 2015 was impacted by asset impairments related to the decrease in crude oil prices and by the significant fluctuation in the U.S. dollar relative to the Canadian dollar.

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, which is a senior debt to EBITDA threshold of 3.5x for a period of up to six months, after which it drops to 3.0x. At March 31, 2015 our senior debt to EBITDA ratio was 1.6x and our debt to funds flow ratio was 1.7x. Debt to funds flow is often used by investors and analysts to evaluate our liquidity, however, this measure is not used by Enerplus to determine compliance with financial covenants.

Total debt net of cash at March 31, 2015 was $1,272.2 million compared to $1,134.9 million at December 31, 2014. Total debt was comprised of $125.7 million of bank indebtedness and $1,149.1 million of senior notes less $2.6 million in cash. At March 31, 2015 we were approximately 13% drawn on our $1.0 billion senior, unsecured bank facility. Subsequent to quarter end, we closed non-core asset sales for proceeds of $185.8 million, net of closing costs, and used the proceeds to repay the drawn balance on our credit facility. The maturities on our senior notes range between 2015 and 2026, with approximately $100 million of scheduled principal repayments during 2015 and none in 2016.

Our working capital deficiency, excluding cash and current deferred financial and tax balances, increased to $290.6 million at March 31, 2015 from $260.5 million at December 31, 2014. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by funds flow, was 197% for the first quarter of 2015 compared to 118% for the same period in 2014. Despite the increase in our adjusted payout ratio we have continued to maintain our financial flexibility through an ongoing focus on cost efficiencies and the success of our non-core asset divestment program. As previously announced, in order to maintain our balance sheet strength we have reduced our monthly dividend by 44% from $0.09/share to $0.05/share effective with our March 2015 dividend, paid in April. We have also decreased our capital spending by 40% compared to 2014 levels, deferring spending and preserving opportunities.

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

The following table lists our financial covenants as at March 31, 2015:

Covenant Description		March 31, 2015
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[(1)]	50%	29%
Senior Notes:	**Maximum Ratio**	
Senior Debt to EBITDA[(2)]	3.0 x – 3.5 x	1.6x
Maximum debt to consolidated present value of total proven reserves	60%	42%
	Minimum Ratio	
EBITDA to Interest	4.0 x	12.9 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, 2015 were $165.9 million and $827.9 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 shareholders' equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes

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

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

Dividends

	Three months ended March 31,	
($ millions, except per share amounts)	2015	2014
Cash dividends	$ 47.4	$ 42.1
Stock Dividend Plan	–	12.8
Total dividends to shareholders	$ 47.4	$ 54.9
Per weighted average share (Basic)	$ 0.23	$ 0.27

We reported a total of $47.4 million or $0.23 per share in dividends to our shareholders in the first quarter of 2015 compared to $54.9 million or $0.27 per share in the first quarter of 2014.

Effective with the April 2015 payment, we reduced the monthly dividend by 44% from $0.09 per share to $0.05 per share to preserve our balance sheet strength in both the near and long term. 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,	
	2015	2014
Share capital ($ millions)	$ 3,125.9	$ 3,081.8
Common shares outstanding (thousands)	206,179	203,839
Weighted average shares outstanding – basic (thousands)	205,845	203,178
Weighted average shares outstanding – diluted (thousands)	205,845	205,878

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 Restricted Share Unit plan. In comparison, during the first quarter of 2014 a total of 1,081,000 shares and $18.9 million of additional equity was issued pursuant to the stock option plan and the currently inactive stock dividend plan. For further details see Note 14.

At March 31, 2015 we had 206,179,000 shares outstanding (2014 – 203,839,000) and at May 7, 2015 we had 206,224,000 shares outstanding.

2015 GUIDANCE

A summary of our 2015 guidance is below. This guidance does not include any unannounced acquisitions or divestments.

There have been no changes to our guidance this quarter, with the exception of a reclassification between operating expenses and transportation costs. This reclassification does not impact our netback, funds flow or net income.

Summary of 2015 Expectations	Target
Average annual production	93,000 – 100,000 BOE/day
Capital spending	$480 million
Production mix (volumes)	42% – 44% crude oil and liquids
Average royalty and production tax rate (% of gross sales, before transportation)	21%
Operating costs	$9.75/BOE (from $11.10/BOE, revised for Marcellus gathering cost reclassification)
Transportation costs	$3.00/BOE (revised for Marcellus gathering cost reclassification)
Cash G&A expenses	$2.40/BOE
U.S. Cash taxes (% of U.S. funds flow)	< 1%

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in 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, 2015, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on January 1, 2015 and ended March 31, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and forward-looking statements within the meaning of applicable securities laws ("forward-looking information"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected 2015 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our funds flow; the proportion and average production volumes associated with curtailments in the Marcellus; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity and foreign exchange risk management programs in 2015 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 2015 and its impact on our production level; potential future asset impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and 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; our future acquisitions and dispositions; and the amount of future cash dividends that we may pay to our shareholders.

The forward-looking information contained in this MD&A reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in further curtailment of production and/or reduced realized prices; current commodity price and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and resource volumes; the continued availability of adequate debt and/or equity financing and funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our funds flow and availability under our bank credit facility to fund our working capital deficiency; the availability of third party services; and the extent of our liabilities. In addition, our 2015 guidance contained in this MD&A is based on the following: a WTI price of US$55/bbl, a NYMEX price of US$2.75/Mcf, an AECO price of $2.50/GJ and a USD/CDN exchange rate of 1.25.

We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

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

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	March 31, 2015	December 31, 2014
Assets			
Current assets			
Cash		$ 2,603	$ 2,036
Accounts receivable	3	151,816	199,745
Deferred financial assets	15	182,713	215,706
Other current assets		9,827	8,241
		346,959	425,728
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	2,559,288	2,632,474
Other capital assets, net	4	20,927	20,591
Property, plant and equipment		2,580,215	2,653,065
Goodwill		640,551	624,390
Deferred income tax asset		488,177	348,117
Deferred financial assets	15	–	30,997
Total Assets		$ 4,055,902	$ 4,082,297
Liabilities			
Current liabilities			
Accounts payable	6	$ 337,537	$ 351,006
Dividends payable		10,309	18,516
Current portion of long-term debt	7	104,430	98,933
Deferred income tax liability		34,495	50,805
Deferred financial credits	15	36,731	10,826
		523,502	530,086
Deferred financial credits	15	–	2,396
Long-term debt	7	1,170,377	1,037,997
Asset retirement obligation	8	295,162	288,692
		1,465,539	1,329,085
Total Liabilities		1,989,041	1,859,171
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value Issued and outstanding: March 31, 2015 – 206 million shares December 31, 2014 – 206 million shares	14	3,125,895	3,120,002
Paid-in capital	14	48,554	46,906
Accumulated deficit		(1,379,825)	(1,039,260)
Accumulated other comprehensive income/(loss)		272,237	95,478
		2,066,861	2,223,126
Total Liabilities & Equity		$ 4,055,902	$ 4,082,297
Contingencies	16		

See accompanying notes to the Condensed Consolidated Financial Statements

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

Three months ended March 31 (CDN$ thousands) unaudited	Note	2015	2014
Revenues			
Oil and natural gas sales, net of royalties	9	$ 204,960	$ 407,740
Commodity derivative instruments gain/(loss)	15	50,398	(32,597)
		255,358	375,143
Expenses			
Production taxes		10,813	19,872
Operating		87,727	79,857
Transportation		26,483	22,333
General and administrative	10	32,080	29,123
Depletion, depreciation, amortization and accretion		132,350	132,180
Asset impairment	5	267,611	–
Interest	11	17,033	15,179
Foreign exchange (gain)/loss	12	104,202	1,469
Other expense/(income)		8,612	2,912
		686,911	302,925
Income/(loss) before taxes		(431,553)	72,218
Current income tax expense/(recovery)	13	63	7,678
Deferred income tax expense/(recovery)	13	(138,410)	24,503
Net Income/(loss)		$ (293,206)	$ 40,037
Other Comprehensive Income/(loss)			
Changes due to marketable securities (net of tax)			
Unrealized gain/(loss)		–	(145)
Realized (gain)/loss reclassified to net income		–	2,503
Change in cumulative translation adjustment		176,759	45,644
Other Comprehensive Income/(loss)		176,759	48,002
Total Comprehensive Income/(loss)		$ (116,447)	$ 88,039
Net income/(loss) per share			
Basic	14	$ (1.42)	$ 0.20
Diluted	14	$ (1.42)	$ 0.19

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Changes in Shareholders' Equity

Three months ended March 31 (CDN$ thousands) unaudited		**2015**		**2014**
Share Capital				
Balance, beginning of year	$	3,120,002	$	3,061,839
Stock Option Plan – cash		2,571		6,138
Share-based compensation – settled		3,095		–
Stock Option Plan – exercised		227		1,012
Stock Dividend Plan		–		12,781
Balance, end of period	$	3,125,895	$	3,081,770
Paid-in Capital				
Balance, beginning of year	$	46,906	$	38,398
Share-based compensation – settled		(3,095)		–
Stock Option Plan – exercised		(227)		(1,012)
Share-based compensation – non-cash		4,970		2,952
Balance, end of period	$	48,554	$	40,338
Accumulated Deficit				
Balance, beginning of year	$	(1,039,260)	$	(1,117,238)
Net income/(loss)		(293,206)		40,037
Dividends		(47,359)		(54,935)
Balance, end of period	$	(1,379,825)	$	(1,132,136)
Accumulated Other Comprehensive Income/(Loss)				
Balance, beginning of year	$	95,478	$	(50,697)
Changes due to marketable securities (net of tax)				
Unrealized gain/(loss)		–		(145)
Realized (gain)/loss reclassified to net income		–		2,503
Change in cumulative translation adjustment		176,759		45,644
Balance, end of period	$	272,237	$	(2,695)
Total Shareholders' Equity	$	2,066,861	$	1,987,277

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

Three months ended March 31 (CDN$ thousands) unaudited	**Note**	**2015**	**2014**
Operating Activities			
Net income/(loss)		$ (293,206)	$ 40,037
Non-cash items add/(deduct):			
Depletion, depreciation, amortization and accretion		132,350	132,180
Asset impairment	5	267,611	–
Changes in fair value of derivative instruments	15	87,499	6,809
Deferred income tax expense/(recovery)	13	(138,410)	24,503
Foreign exchange (gain)/loss on debt and working capital	12	88,014	10,987
Share-based compensation	14	4,970	2,952
Amortization of debt issue costs		240	246
Asset divestments (gain)/loss		–	2,798
Derivative settlement of foreign exchange swaps		(39,904)	–
Asset retirement obligation expenditures	8	(3,890)	(4,292)
Changes in non-cash operating working capital	17	25,822	(75,810)
Cash flow from operating activities		131,096	140,410
Financing Activities			
Proceeds from the issuance of shares	14	2,571	6,138
Cash dividends	14	(47,359)	(42,154)
Change in bank credit facility		45,820	(30,570)
Derivative settlement of foreign exchange swaps		39,904	–
Changes in non-cash financing working capital		(8,207)	101
Cash flow from financing activities		32,729	(66,485)
Investing Activities			
Capital and office expenditures		(167,888)	(218,193)
Property and land acquisitions		236	(9,969)
Property dispositions		3,712	117,225
Sale of marketable securities		–	13,300
Changes in non-cash investing working capital		931	24,677
Cash flow from investing activities		(163,009)	(72,960)
Effect of exchange rate changes on cash		(249)	1,782
Change in cash		567	2,747
Cash, beginning of period		2,036	2,990
Cash, end of period		$ 2,603	$ 5,737

See accompanying notes to the Condensed Consolidated Financial Statements

Notes to Condensed Consolidated Financial Statements

(unaudited)

1) REPORTING ENTITY

These interim Condensed Consolidated Financial Statements ("interim Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation ("The Company" or "Enerplus") including its Canadian and U.S. subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada. The interim Consolidated Financial Statements were authorized for issue by the Board of Directors on May 7, 2015.

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, 2015, and the 2014 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, 2014. 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, 2014.

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, 2015	December 31, 2014
Accrued receivables	$ 111,005	$ 136,949
Accounts receivable – trade	37,113	41,618
Current income tax receivable	6,474	23,900
Allowance for doubtful accounts	(2,776)	(2,722)
Total accounts receivable	$ 151,816	$ 199,745

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

As at March 31, 2015 ($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties	$ 13,084,358	$ 10,525,070	$ 2,559,288
Other capital assets	100,057	79,130	20,927
Total PP&E	$ 13,184,415	$ 10,604,200	$ 2,580,215

As at December 31, 2014 ($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties	$ 12,478,953	$ 9,846,479	$ 2,632,474
Other capital assets	97,893	77,302	20,591
Total PP&E	$ 12,576,846	$ 9,923,781	$ 2,653,065

5) ASSET IMPAIRMENT

	Three months ended March 31	
($ thousands)	2015	2014
Oil and natural gas properties	$ 267,611	$ –
Impairment expense	$ 267,611	$ –

For the three months ended March 31, 2015 non-cash impairment of $267.6 million was recorded in the United States cost centre due to lower 12-month average trailing crude oil prices. No impairments were recorded to the Canadian cost centre for the same period, and no impairments were recorded in either the United States or Canada cost centre for the period ending March 31, 2014.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from March 31, 2014 through March 31, 2015:

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 2015	$ 82.73	$ 1.14	$ 84.61	$ 3.88	$ 3.86
Q4 2014	94.99	1.09	94.84	4.30	4.60
Q3 2014	99.08	1.08	95.97	4.23	4.42
Q2 2014	100.27	1.06	98.28	4.08	4.05
Q1 2014	98.46	1.05	95.45	3.98	3.79

6) ACCOUNTS PAYABLE

($ thousands)	March 31, 2015	December 31, 2014
Accrued payables	$ 246,548	$ 239,773
Accounts payable – trade	90,989	111,233
Total accounts payable	$ 337,537	$ 351,006

7) DEBT

($ thousands)	March 31, 2015	December 31, 2014
Current:		
Senior notes	$ 104,430	$ 98,933
	104,430	98,933
Long-term:		
Bank credit facility	$ 125,737	$ 79,917
Senior notes	1,044,640	958,080
	1,170,377	1,037,997
Total debt	$ 1,274,807	$ 1,136,930

8) ASSET RETIREMENT OBLIGATION

Enerplus has estimated the present value of its asset retirement obligation to be $295.2 million at March 31, 2015 compared to $288.7 million at December 31, 2014, based on a total undiscounted liability of $741.8 million and $730.9 million, respectively. The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.89% (December 31, 2014 – 5.92%).

($ thousands)	Three months ended March 31, 2015	Year ended December 31, 2014
Balance, beginning of year	$ 288,692	$ 291,761
Change in estimates	5,755	4,378
Property acquisition and development activity	492	1,778
Dispositions	(40)	(4,313)
Settlements	(3,890)	(19,409)
Accretion expense	4,153	14,497
Balance, end of period	$ 295,162	$ 288,692

9) OIL AND NATURAL GAS SALES

	Three months ended March 31	
($ thousands)	2015	2014
Oil and natural gas sales	$ 244,077	$ 495,024
Royalties(1)	(39,117)	(87,284)
Oil and natural gas sales, net of royalties	$ 204,960	$ 407,740

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

10) GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended March 31	
($ thousands)	2015	2014
General and administrative expense	$ 21,435	$ 20,529
Share-based compensation expense	10,645	8,594
General and administrative expense	$ 32,080	$ 29,123

11) INTEREST EXPENSE

	Three months ended March 31	
($ thousands)	2015	2014
Realized:		
Interest on bank debt and senior notes	$ 16,793	$ 14,666
Unrealized:		
Cross currency interest rate swap (gain)/loss	–	267
Amortization of debt issue costs	240	246
Interest expense	$ 17,033	$ 15,179

12) FOREIGN EXCHANGE

($ thousands)	Three months ended March 31 2015		2014	
Realized:				
Foreign exchange (gain)/loss	$	(35,574)	$	50
Unrealized:				
Translation of U.S. dollar debt and working capital (gain)/loss		88,014		10,987
Cross currency interest rate swap (gain)/loss		–		(1,245)
Foreign exchange derivatives (gain)/loss		51,762		(8,323)
Foreign exchange (gain)/loss	$	104,202	$	1,469

13) INCOME TAXES

($ thousands)	Three months ended March 31 2015		2014	
Current tax expense/(recovery)				
Canada	$	–	$	(184)
United States		63		7,862
Current tax expense/(recovery)		63		7,678
Deferred tax expense/(recovery)				
Canada	$	(9,263)	$	1,687
United States		(129,147)		22,816
Deferred tax expense/(recovery)		(138,410)		24,503
Income tax expense/(recovery)	$	(138,347)	$	32,181

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

14) SHAREHOLDERS' EQUITY

a) Share Capital

	Three months ended March 31 2015		Year ended December 31 2014	
Authorized unlimited number of common shares **Issued:** (thousands)	Shares	Amount	Shares	Amount
Balance, beginning of year	205,732	$ 3,120,002	202,758	$ 3,061,839
Issued for cash:				
Stock Option Plan	189	2,571	1,944	31,350
Non-cash:				
Share-based compensation – settled	258	3,095	–	–
Stock Option Plan – exercised	–	227	–	4,978
Stock Dividend Plan(1)	–	–	1,030	21,835
Balance, end of period	206,179	$ 3,125,895	205,732	$ 3,120,002

(1) Effective with the October, 2014 dividend, Enerplus suspended the Stock Dividend Plan.

b) Dividends

($ thousands)	Three months ended March 31 2015	2014
Cash dividends	$ 47,359	$ 42,154
Stock dividends[(1)]	–	12,781
Dividends to shareholders	$ 47,359	$ 54,935

(1) Effective with the October 2014 dividend Enerplus suspended the Stock Dividend Plan.

c) Share-based Compensation

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

($ thousands)	Three months ended March 31 2015	2014
Cash:		
Long-term incentive plans expense	$ 7,274	$ 6,864
Non-Cash:		
Share-based compensation	4,970	2,952
Equity swap (gain)/loss	(1,599)	(1,222)
Share-based compensation expense	$ 10,645	$ 8,594

(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 our grant in March of 2014 and any prior grants will continue to be settled in cash.

The following table summarizes the PSU, RSU and Director Share Unit ("DSU") activity for the three months ended March 31, 2015:

For the three months ended March 31, 2015	Cash-settled LTI Plans			Equity-settled LTI Plans		
(thousands of units)	PSU	RSU	DSU	PSU	RSU	Total
Balance, beginning of year	406	398	122	510	775	2,211
Granted	–	–	77	907	1,333	2,317
Vested	–	(211)	–	–	(258)	(469)
Forfeited	(10)	(19)	–	(13)	(43)	(85)
Balance, end of period	396	168	199	1,404	1,807	3,974

Cash-settled LTI Plans

For three months ended March 31, 2015 the Company recorded cash share-based compensation expense of $7.3 million (2014 – $6.9 million). For the three months ended March 31, 2015, the Company made cash payments of $5.6 million related to its cash-settled plans (2014 – $11.5 million).

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

At March 31, 2015 ($ thousands, except for years)		**PSU**[1]		**RSU**		**DSU**		**Total**
Cumulative recognized share-based compensation expense	$	10,316	$	2,441	$	3,089	$	15,846
Unrecognized share-based compensation expense		2,472		574		–		3,046
Intrinsic value	$	12,788	$	3,015	$	3,089	$	18,892
Weighted-average remaining contractual term (years)		0.6		0.7		–		

(1) Includes estimated performance multipliers.

Equity-settled LTI Plans

For the three months ended March 31, 2015 the Company recorded non-cash share-based compensation expense of $5.0 million (2014 – $3.0 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, 2015 ($ thousands, except for years)		**PSU**[1]		**RSU**		**Total**
Cumulative recognized share-based compensation expense	$	3,820	$	10,109	$	13,929
Unrecognized share-based compensation expense		20,204		18,342		38,546
Fair value	$	24,024	$	28,451	$	52,475
Weighted-average remaining contractual term (years)		2.5		1.8		

(1) Includes estimated performance multipliers.

(ii) Stock Option Plan

The Company did not grant any stock options for the three months ended March 31, 2015. The following table summarizes the stock option plan activity for the period ended March 31, 2015:

Period ended March 31, 2015	**Number of Options** (thousands)		**Weighted Average Exercise Price**
Options outstanding, beginning of year	10,368	$	18.65
Granted	–		–
Exercised	(189)		13.71
Forfeited	(388)		19.98
Options outstanding, end of period	9,791	$	18.70
Options exercisable, end of period	7,764	$	19.95

At March 31, 2015, 7,764,000 options were exercisable at a weighted average reduced exercise price of $19.95 with a weighted average remaining contractual term of 3.9 years, giving an aggregate intrinsic value of nil (2014 – $20.3 million). The intrinsic value of options exercised for the period ended March 31, 2015 was $0.1 million (2014 – $2.9 million).

At March 31, 2015 the total share-based compensation expense related to non-vested options not yet recognized was $0.6 million. The expense is expected to be recognized in net income over a weighted-average period of 0.9 years.

d) Paid-in Capital

The following table summarizes the paid-in capital activity for the three months ended March 31, 2015 and the year ended December 31, 2014:

($ thousands)	Three months ended March 31, 2015	Year ended December 31, 2014
Balance, beginning of year	$ 46,906	$ 38,398
Share-based compensation – settled	(3,095)	–
Stock Option Plan – exercised	(227)	(4,978)
Share-based compensation – non-cash	4,970	13,486
Balance, end of period	$ 48,554	$ 46,906

e) Basic and Diluted Earnings Per Share

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

	Three months ended March 31	
(thousands, except per share amounts)	2015	2014
Net income/(loss)	$ (293,206)	$ 40,037
Weighted average shares outstanding – Basic	205,845	203,178
Dilutive impact of share-based compensation(1)	–	2,700
Weighted average shares outstanding – Diluted	205,845	205,878
Net income/(loss) per share		
Basic	$ (1.42)	$ 0.20
Diluted(1)	(1.42)	0.19

(1) For the three months ended March 31, 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, 2015, 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, 2015 senior notes included in long-term debt had a carrying value of $1,170.4 million and a fair value of $1,276.2 million (December 31, 2014 – $1,038.0 million and $1,150.0 million, respectively).

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

b) Derivative Financial Instruments

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

The following table summarizes the change in fair value for the three months ended March 31, 2015 and 2014:

Gain/(Loss) ($ thousands)	March 31, 2015	March 31, 2014	Income Statement Presentation
Cross Currency Interest Rate Swap:			
Interest	$ –	$ (267)	Interest expense
Foreign Exchange	–	1,245	Foreign exchange
Foreign Exchange Derivatives	(51,762)	8,323	Foreign exchange
Electricity Swaps	(927)	(46)	Operating expense
Equity Swaps	1,599	1,222	General and administrative expense
Commodity Derivative Instruments:			
Oil	(35,959)	(9,393)	Commodity derivative instruments
Gas	(450)	(7,893)	
Total	$ (87,499)	$ (6,809)	

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

	Three months ended March 31	
($ thousands)	2015	2014
Change in fair value gain/(loss)	$ (36,409)	$ (17,286)
Net realized cash gain/(loss)	86,807	(15,311)
Commodity derivative instruments gain/(loss)	$ 50,398	$ (32,597)

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

	March 31, 2015		December 31, 2014			
	Assets	Liabilities	Assets		Liabilities	
($ thousands)	Current	Current	Current	Long-term	Current	Long-term
Foreign Exchange Derivatives	$ 2,700	$ 32,615	$ 1,616	$ 28,665	$ 8,434	$ –
Electricity Swaps	–	2,295	–	–	1,368	–
Equity Swaps	–	1,821	–	–	1,024	2,396
Commodity Derivative Instruments:						
Oil	131,228	–	167,187	–	–	–
Gas	48,785	–	46,903	2,332	–	–
Total	$ 182,713	$ 36,731	$ 215,706	$ 30,997	$ 10,826	$ 2,396

c) Risk Management

(i) Market Risk

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

Commodity Price Risk:

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

The following tables summarize Enerplus' price risk management positions at May 5, 2015:

Crude Oil Instruments:

Instrument Type[1]	bbls/day	US$/bbl
April 1, 2015 – April 30, 2015		
WTI Swap	17,500	88.85
WCS Differential Swap	4,000	(18.24)
WTI Purchased Call	4,000	93.00
WTI Sold Put	4,000	62.23
May 1, 2015 – May 31, 2015		
WTI Swap	17,500	89.18
WCS Differential Swap	4,000	(18.24)
WTI Purchased Call	4,000	93.00
WTI Sold Put	4,000	62.23
Jun 1, 2015 – Jun 30, 2015		
WTI Swap	15,500	93.58
WCS Differential Swap	4,000	(18.24)
WTI Purchased Call	4,000	93.00
WTI Sold Put	4,000	62.23
Jul 1, 2015 – Dec 31, 2015		
WTI Swap	8,000	93.86
WCS Differential Swap	3,000	(17.85)
WTI Purchased Call	4,000	93.00
WTI Sold Put	4,000	62.23
Jan 1, 2016 – Dec 31, 2016		
WTI Swap	2,000	65.50
WTI Purchased Put	6,000	65.00
WTI Sold Put	6,000	50.00
WTI Sold Call	6,000	80.00

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

Natural Gas Instruments:

Instrument Type	MMcf/day	US$/Mcf
Apr 1, 2015 – Jun 30, 2015		
NYMEX Swap	110.0	3.98
NYMEX Purchased Call	5.0	4.29
NYMEX Sold Put	5.0	3.25
NYMEX Sold Call	5.0	5.00
Jul 1, 2015 – Sep 30, 2015		
NYMEX Swap	135.0	3.83
NYMEX Purchased Call	5.0	4.29
NYMEX Sold Put	5.0	3.25
NYMEX Sold Call	5.0	5.00
Oct 1, 2015 – Oct 31, 2015		
NYMEX Swap	115.0	3.85
NYMEX Purchased Call	5.0	4.29
NYMEX Sold Put	5.0	3.25
NYMEX Sold Call	5.0	5.00
Nov 1, 2015 – Dec 31, 2015		
NYMEX Swap	95.0	4.04
NYMEX Purchased Call	5.0	4.29
NYMEX Sold Put	5.0	3.25
NYMEX Sold Call	5.0	5.00

Electricity Instruments:

Instrument Type	MWh	CDN$/MWh
Apr 1, 2015 – Dec 31, 2015 AESO Power Swap	16.0	48.30
Jan 1, 2016 – Dec 31, 2016 AESO Power Swap	12.0	47.00

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

Foreign Exchange Risk:

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

Foreign Exchange Derivatives:

During 2014, Enerplus entered into foreign exchange collars to hedge a portion of its foreign exchange exposure on U.S. dollar denominated oil and gas sales. The following contracts are outstanding at May 5, 2015:

Instrument Type(1)	Monthly Notional Amount (US$ millions)	Floor	Ceiling	Conditional Ceiling(2)
Apr 1, 2015 – Dec 31, 2015	24.0	1.1088	1.1845	1.1263

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

During 2007 Enerplus entered into foreign exchange swaps on US$54.0 million of notional debt at an average US$/CDN$ exchange rate of 1.02. The remaining $10.8 million notional amount under the swap matures in October 2015 in conjunction with the final principal repayment on the US$54.0 million senior notes.

During 2011 Enerplus entered into foreign exchange swaps on US$175.0 million of notional debt at approximately par. During the quarter, Enerplus unwound these swaps and recognized a gain of $39.9 million and an offsetting non-cash loss of $27.6 million which have been included in foreign exchange gain/loss on the Consolidated Statements of Income/(Loss).

Interest Rate Risk:

At March 31, 2015, approximately 90% of Enerplus' debt was based on fixed interest rates and 10% was based on floating interest rates. At March 31, 2015 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 2015 and 2017 and has effectively fixed the future settlement cost on 630,000 shares at a weighted average price of $15.82 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, 2015 approximately 73% of Enerplus' marketing receivables were with companies considered investment grade.

At March 31, 2015 approximately $7.4 million or 5% of Enerplus' total accounts receivable were aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at March 31, 2015 was $2.8 million (December 31, 2014 – $2.7 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, 2015, 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, 2015	Three months ended March 31, 2014
Accounts receivable	$ 47,966	$ (37,424)
Other current assets	(4,798)	923
Accounts payable	(17,346)	(39,309)
	$ 25,822	$ (75,810)

b) Supplementary Cash Flow Information

($ thousands)	Three months ended, March 31, 2015	Three months ended, March 31, 2014
Income taxes paid/(received)	$ (19,344)	$ (134)
Interest paid	$ 6,482	$ 2,383

18) SUBSEQUENT EVENT

Subsequent to March 31, 2015 Enerplus closed non-core asset dispositions for proceeds of $185.8 million, after closing adjustments.

BOARD OF DIRECTORS

Elliott Pew(1)(2)
Corporate Director
Boerne, Texas

David H. Barr(12)
Corporate Director
The Woodlands, Texas

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Progress Energy Canada Ltd.
Calgary, Alberta

Edwin V. Dodge(11)
Corporate Director
Vancouver, British Columbia

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

Hilary A. Foulkes(5)(11)
Corporate Director
Calgary, Alberta

James B. Fraser(7)(11)
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Polson, Montana

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Corporate Director
Calgary, Alberta

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Corporate Director
Calgary, Alberta

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

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

Sheldon B. Steeves(5)(8)
Corporate Director
Calgary, Alberta

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

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas
President & Chief Executive Officer

Ray J. Daniels
Senior Vice President, Operations

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

Robert J. Waters
Senior Vice President & Chief Financial Officer

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Vice President, Corporate & Investor Relations

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President, U.S. Operations

Lisa M. Ower
Vice President, Human Resources

P. Scott Walsh
Vice President, Information & Corporate Services

Kenneth W. Young
Vice President, Land & Operations Services

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION

Enerplus Resources (USA) Corporation

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Netherland, Sewell & Associates,Inc.
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ABBREVIATIONS

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

Enerplus is a North American energy producer with a portfolio of high quality oil and gas assets in resource plays that offer significant organic growth potential. We are focused on creating value for our investors through the execution of a disciplined capital investment strategy that supports the successful development of our properties, and a monthly dividend to shareholders. We are a responsible developer of resources that strives to provide investors with a competitive return comprised of both growth and income.

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