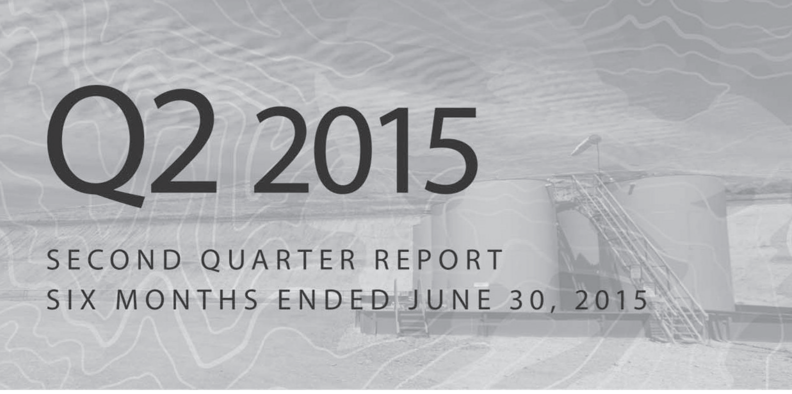

Q2 2015

enerPLUS

SECOND QUARTER REPORT
SIX MONTHS ENDED JUNE 30, 2015

SELECTED FINANCIAL RESULTS	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Financial (000's)				
Funds Flow[4]	$ 160,436	$ 213,211	$ 269,600	$ 433,723
Cash and Stock Dividends	30,935	55,214	78,294	110,149
Net Income/(Loss)	(312,544)	39,957	(605,750)	79,994
Debt Outstanding – net of cash	1,120,680	1,067,590	1,120,680	1,067,590
Capital Spending	147,979	204,427	314,989	422,190
Property Divestments	187,801	(525)	191,513	116,700
Debt to Funds Flow Ratio[4]	1.6x	1.3x	1.6x	1.3x
Financial per Weighted Average Shares Outstanding				
Funds Flow	$ 0.78	$ 1.04	$ 1.31	$ 2.13
Net Income/(Loss)	(1.52)	0.20	(2.94)	0.39
Weighted Average Number of Shares Outstanding (000's)	206,208	204,158	206,028	203,671
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 30.53	$ 53.32	$ 28.78	$ 54.45
Royalties and Production Taxes	(6.23)	(11.58)	(5.88)	(11.81)
Commodity Derivative Instruments	7.47	(2.60)	8.48	(2.17)
Cash Operating Expenses	(8.12)	(9.12)	(8.81)	(9.04)
Transportation Costs	(2.87)	(2.39)	(2.89)	(2.45)
General and Administrative	(2.03)	(1.97)	(2.19)	(2.14)
Cash Share-Based Compensation	0.13	(1.12)	(0.32)	(0.95)
Interest, Foreign Exchange and Other Expenses	(2.48)	(1.61)	(2.87)	(1.63)
Taxes	0.01	(0.40)	–	(0.63)
Funds Flow	$ 16.41	$ 22.53	$ 14.30	$ 23.63

SELECTED OPERATING RESULTS	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Average Daily Production[2]				
Crude Oil (bbls/day)	41,122	39,863	40,243	38,817
Natural Gas Liquids (bbls/day)	5,145	3,636	4,444	3,450
Natural Gas (Mcf/day)	366,971	362,929	356,836	354,906
Total (BOE/day)	107,429	103,987	104,160	101,418
% Crude Oil and Natural Gas Liquids	43%	42%	43%	42%
Average Selling Price[2][3]				
Crude Oil (per bbl)	$ 58.26	$ 96.46	$ 51.35	$ 93.25
Natural Gas Liquids (per bbl)	20.88	51.80	21.55	57.66
Natural Gas (per Mcf)	2.09	4.15	2.32	4.46
Net Wells Drilled	8	14	36	44

(1) Non-cash amounts have been excluded.
(2) Based on Company interest production volumes. See "Basis of Presentation" section in the following MD&A.
(3) Before transportation costs, royalties and commodity derivative instruments.
(4) These non-GAAP measures may not be directly comparable to similar measures presented by other entities. See "Non-GAAP Measures" section in the following MD&A.

Average Benchmark Pricing	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
WTI Crude Oil (US$/bbl)	$ 57.94	$ 102.99	$ 53.29	$ 100.84
AECO – monthly index (CDN$/Mcf)	2.67	4.68	2.81	4.72
AECO – daily index (CDN$/Mcf)	2.64	4.69	2.70	5.20
NYMEX – last day (US$/Mcf)	2.64	4.67	2.81	4.80
US/CDN exchange rate	1.23	1.09	1.24	1.10

Share Trading Summary For the three months ended June 30, 2015	CDN* – ERF (CDN$)	U.S.** – ERF (US$)
High	$ 16.09	$ 13.16
Low	10.61	8.56
Close	10.96	8.79

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

2015 Dividends per Share Payment Month	CDN$	US$[1]
First Quarter Total	$ 0.27	$ 0.22
April	$ 0.05	$ 0.04
May	0.05	0.04
June	0.05	0.04
Second Quarter Total	$ 0.15	$ 0.12
Total Year-to-Date	$ 0.42	$ 0.34

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

PRESIDENT'S MESSAGE

Through the second quarter of 2015, Enerplus continued to focus on operational execution under a disciplined capital program. We delivered production growth, improved cost performance and maintained a strong financial position.

Production volumes grew by 7% quarter over quarter to 107,429 BOE per day. This growth was primarily driven by increased activity in North Dakota, where production averaged approximately 27,100 BOE per day, up over 25% from the first quarter of 2015. We also saw growth from our gas portfolio with our Canadian Deep Basin and Marcellus assets showing production increases over the first quarter of 2015. Our production mix was essentially unchanged from the previous quarter, with crude oil and natural gas liquids accounting for 43% of production.

As a result of continued operational outperformance, we are increasing our average annual production guidance for both liquids and gas to 100,000-104,000 BOE per day from 97,000-103,000 BOE per day. We expect approximately 44,000-46,000 barrels per day of crude oil and natural gas liquids. This guidance includes year to date divestments of approximately 1,900 BOE per day.

We spent $148 million in our core areas during the quarter, and are on track to meet our annual capital spending guidance of $540 million, despite the weak Canadian dollar. Approximately 75% of spending in the quarter was directed to our North Dakota properties. In total we drilled 7.8 net wells and brought 22 net wells on-stream across our portfolio in the second quarter.

Both operating costs and G&A expenses for the quarter came in lower than forecast, at $7.85 per BOE and $2.03 per BOE, respectively. Based on our cost savings realized to date and our increased production target, we are decreasing our annual operating cost guidance to $9.25 per BOE from $9.75 per BOE and our G&A expense guidance to $2.25 per BOE from $2.40 per BOE, representing a combined decrease of $0.65 per BOE.

Funds flow increased by 47% to $160 million from the first quarter. This was largely a result of higher production, lower costs and improved crude oil prices, and despite slightly weaker gas pricing. Funds flow was also supported by our hedging program which generated gains of $73 million during the second quarter.

We incurred a non-cash asset impairment charge in the quarter of $497 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 commodity prices in the fourth quarter of 2014 and the first half of 2015.

During the quarter, we closed our previously announced non-core asset sales, along with the sale of additional minor non-core properties for proceeds of $188 million.

Our focus on cost control, strong 2015 hedge position, divestment proceeds, and disciplined capital spending have helped preserve our strong financial position. We ended the quarter with an improved trailing debt to funds flow ratio of 1.6 times, down from 1.7 times in the first quarter of 2015. At June 30, 2015, we were approximately 8% drawn on our $1 billion credit facility. Following the next scheduled repayment of our senior notes in October 2015 of US$10.8 million, we have no scheduled debt repayments until June of 2017.

Production and Capital Spending

	Three months ended June 30, 2015		Six months ended June 30, 2015	
	Average Production Volumes	Capital Spending ($ millions)	Average Production Volumes	Capital Spending ($ millions)
Crude Oil & NGLs (bbls/day)				
Canada	17,598	17.3	18,460	72.4
United States	28,669	110.8	26,227	189.2
Total Crude Oil & NGLs (bbls/day)	**46,267**	**128.1**	**44,687**	**261.6**
Natural Gas (Mcf/day)				
Canada	144,788	7.3	140,129	29.1
United States	222,183	12.6	216,707	24.3
Total Natural Gas (Mcf/day)	**366,971**	**19.9**	**356,836**	**53.4**
Company Total (BOE/day)	**107,429**	**148.0**	**104,160**	**315.0**

Net Drilling Activity*** – for the three months ended June 30, 2015

	Wells Drilled	Wells Pending Completion/Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Crude Oil				
Canada	1.0	1.0	6.6	–
United States	5.5	4.5	9.2	–
Total Crude Oil	**6.5**	**5.5**	**15.8**	**–**
Natural Gas				
Canada	0.7	0.7	3.0	–
United States	0.7	0.4	3.2	–
Total Natural Gas	**1.4**	**1.1**	**6.2**	**–**
Company Total	**7.8**	**6.5**	**22.0**	**–**

* Wells drilled during the quarter that are pending potential completion/tie-in or abandonment as at June 30, 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 re-established production growth in North Dakota in the second quarter of 2015. Production from Fort Berthold averaged approximately 27,100 BOE per day during the quarter, up over 25% from the first quarter of 2015. We drilled 5.5 net wells in Fort Berthold with 9.2 net wells brought on-stream during the quarter for a total capital outlay of $111 million.

We continue to run a one-rig drilling program as we work through our inventory of drilled uncompleted wells at Fort Berthold and expect to drill approximately 8 net wells in the second half of the year. We are ahead of schedule on our 2015 completions activity. During the first six months of 2015 we brought approximately 13 net wells on stream. We expect to bring up to 10 additional net wells on stream during the second half of the year. This activity is broadly weighted towards the third quarter and we expect production growth through the remainder of the year. Our high intensity completion design continues to yield excellent results. The average initial 30 day production rate (IP30) of our operated on-stream wells in the quarter was over 2,000 BOE per day, exceeding our high end type curve. We continue to see improved well costs with current costs down over 20% from 2014 levels.

In the Marcellus, continued low levels of spending ($12.6 million in the second quarter) led to 0.7 net wells drilled and 3.2 net wells on-stream. Despite the reduced activity, well outperformance resulted in production of 201 MMcf per day during the second quarter, a modest increase from the previous quarter.

In the Deep Basin, we drilled three excellent wells at our Ansell pad. The average peak 30 day production rate for a well on the pad was approximately 10 MMcf per day, on trend with our high end type curve.

Crude Oil & Natural Gas Pricing

The West Texas Intermediate (WTI) benchmark price for crude oil increased by 19% quarter-over-quarter to average US$57.94 per barrel in the second quarter. The strength in WTI prices combined with the narrowing of crude oil differentials in both Canada and the U.S. resulted in a 32% improvement in the selling price for our crude oil compared to the previous quarter. The average realized sales price for our crude oil was $58.26 per barrel during the quarter with crude oil properties generating approximately 90% of our corporate netback.

On the natural gas side, both AECO and NYMEX weakened from the previous quarter due to continued high production and increased storage levels across the continent. In the Marcellus, our realized differential widened US$0.07 per Mcf from the previous quarter to average US$1.39 per Mcf. Overall, as a result of lower benchmark pricing and continued pricing weakness in the Marcellus producing region, our realized sales price for gas fell by 19% compared to the previous quarter to average $2.09 per Mcf.

We continued to add to our commodity hedge position for both 2015 and 2016. For the second half of 2015, we have an average of 11,250 barrels per day of crude oil hedged (representing approximately 35% of our expected crude oil production net of royalties) at an average floor price of US$84.58 per barrel through a combination of swaps and three way collar structures. For 2016, we have an average of 11,000 barrels per day of crude oil hedged (representing approximately 34% of our expected crude oil production net of royalties) at an average floor price of US$64.35 per barrel through a combination of swaps and three way collar structures.

We have also added to our NYMEX gas hedging position. For the second half of 2015, we are swapped on an average of 128 MMcf per day at an average price of US$3.82 per Mcf, representing approximately 47% of our forecasted natural gas production after royalties. For 2016, we have 25 MMcf per day, or 9% of our forecasted natural gas production after royalties, hedged through three-way collars with an average floor price of US$3.00 per Mcf.

Outlook

We delivered another quarter of strong operating results. On the back of this operational momentum and improved cost efficiencies, we are increasing our 2015 production guidance and reducing our operating and G&A expense guidance.

We continue to navigate through this challenging commodity price environment with a strong balance sheet and hedging program that will support our funds flow. We remain focused on driving improvement in our operational efficiencies through both reducing our cost structures and optimizing well performance. Above all, the low commodity prices have not stopped us from committing the time and resources to ensure safe, responsible and sustainable operations across our business.

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 August 6, 2015 and is to be read in conjunction with:

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

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

BASIS OF PRESENTATION

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

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

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

NON-GAAP MEASURES

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

"Netback" is used by Enerplus and is useful to investors and securities analysts in evaluating operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating costs and transportation.

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

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

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

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

"Debt to Funds Flow Ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The debt to funds flow ratio is calculated as total debt net of cash, divided by a trailing 12 months of funds flow. This measure is not equivalent to Debt to Earnings before Interest, Taxes, Depreciation and Amortization and other non-cash charges ("EBITDA") and is not a debt covenant.

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

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

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

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

OVERVIEW

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

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

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

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

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

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

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

RESULTS OF OPERATIONS

Production

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

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

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

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

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

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

Pricing

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

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

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

Crude Oil and Natural Gas Liquids

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

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

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

Natural Gas

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

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

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

Foreign Exchange

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

Price Risk Management

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

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

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

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

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

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

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

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

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

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

ACCOUNTING FOR PRICE RISK MANAGEMENT

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

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

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

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

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

Revenues

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

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

Royalties and Production Taxes

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

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

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

Operating Expenses

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

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

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

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

Transportation Costs

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

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

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

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

Netbacks

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

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

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

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

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

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

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

General and Administrative Expenses

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

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

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

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

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

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

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

Interest Expense

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

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

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

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

Foreign Exchange

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

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

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

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

Capital Investment

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

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

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

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

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

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

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

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

Impairment

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

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

Asset Retirement Obligation

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

Income Taxes

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

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

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

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

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

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

SELECTED QUARTERLY CANADIAN AND U.S. FINANCIAL RESULTS

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

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

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

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

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Diluted
2015				
Second Quarter	$ 251.7	$ (312.5)	$ (1.52)	$ (1.52)
First Quarter	205.0	(293.2)	(1.42)	(1.42)
Total 2015	$ 456.7	$ (605.7)	$ (2.94)	$ (2.94)
2014				
Fourth Quarter	$ 325.3	$ 151.7	$ 0.74	$ 0.73
Third Quarter	378.3	67.4	0.33	0.32
Second Quarter	414.9	40.0	0.20	0.19
First Quarter	407.7	40.0	0.20	0.19
Total 2014	$ 1,526.2	$ 299.1	$ 1.46	$ 1.44
2013				
Fourth Quarter	$ 332.4	$ 29.6	$ 0.15	$ 0.15
Third Quarter	365.4	(3.7)	(0.02)	(0.02)
Second Quarter	341.3	38.5	0.19	0.19
First Quarter	313.4	(16.4)	(0.08)	(0.08)
Total 2013	$ 1,352.5	$ 48.0	$ 0.24	$ 0.24

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

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

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

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

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

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

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

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

Definitions

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

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

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

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

Footnotes

(1) Upon completion of a material acquisition, the Total Debt to Capitalization maximum ratio may increase to 55% for a period extending to and including the second full fiscal quarter after the completion of the acquisition.
(2) Senior Debt to EBITDA maximum ratio for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.

Dividends

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

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

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

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

Shareholders' Capital

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

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

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

U.S. Filing Status

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

2015 GUIDANCE

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

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

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of disclosure in Issuer's Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at June 30, 2015, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on April 1, 2015 and ended June 30, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

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

The forward-looking information contained in this MD&A reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in further curtailment of production and/or reduced realized prices; current commodity price and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and resource volumes; the continued availability of adequate debt and/or equity financing and funds flow to fund our capital, operating and working capital requirements, and dividend payments, as needed; the continued availability and sufficiency of our funds flow and availability under our bank credit facility to fund our working capital deficiency; the availability of third party services; and the extent of our liabilities. In addition, our 2015 guidance contained in this MD&A is based on the following July 22, 2015 forward prices: a WTI price of US$51.99/bbl, a NYMEX price of US$2.89/Mcf, and AECO price of $2.75/GJ and a CDN/USD exchange rate of 1.27.

We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information included in this MD&A is not a guarantee of future performance and should be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: changes in, including further decline of, commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; our risk management programs, including commodity hedging, being less effective in protecting our balance sheet and funds flow than anticipated; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; changes in estimates of our reserves and resource volumes; limited, unfavorable or a lack of access to capital markets; our inability to comply with covenants under our bank credit facility and senior notes; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; failure to complete any of the anticipated acquisitions or dispositions; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in our Annual MD&A and in our other public filings).

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	June 30, 2015	December 31, 2014
Assets			
Current Assets			
Cash		$ 1,002	$ 2,036
Accounts receivable	3	161,284	199,745
Deferred financial assets	15	83,617	215,706
Other current assets		14,868	8,241
		260,771	425,728
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	1,852,801	2,632,474
Other capital assets, net	4	20,265	20,591
Property, plant and equipment		1,873,066	2,653,065
Goodwill		637,429	624,390
Deferred income tax asset		685,988	348,117
Deferred financial assets	15	6,446	30,997
Total Assets		$ 3,463,700	$ 4,082,297
Liabilities			
Current liabilities			
Accounts payable	6	$ 317,043	$ 351,006
Dividends payable		10,311	18,516
Current portion of long-term debt	7	13,472	98,933
Deferred income tax liability		16,254	50,805
Deferred financial credits	15	17,819	10,826
		374,899	530,086
Deferred financial credits	15	–	2,396
Long-term debt	7	1,108,210	1,037,997
Asset retirement obligation	8	282,474	288,692
		1,390,684	1,329,085
Total Liabilities		1,765,583	1,859,171
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value Issued and outstanding: June 30, 2015 – 206 million shares December 31, 2014 – 206 million shares	14	3,126,568	3,120,002
Paid-in capital	14	53,106	46,906
Accumulated deficit		(1,723,304)	(1,039,260)
Accumulated other comprehensive income/(loss)		241,747	95,478
		1,698,117	2,223,126
Total Liabilities & Equity		$ 3,463,700	$ 4,082,297
Contingencies	16		

See accompanying notes to the Condensed Consolidated Financial Statements

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

(CDN$ thousands) unaudited	Note	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Revenues					
Oil and natural gas sales, net of royalties	9	$ 251,730	$ 414,925	$ 456,690	$ 822,665
Commodity derivative instruments gain/(loss)	15	(19,751)	(44,069)	30,647	(76,666)
		231,979	370,856	487,337	745,999
Expenses					
Production taxes		14,220	19,974	25,033	39,846
Operating		76,744	86,018	164,471	165,875
Transportation		28,018	22,630	54,501	44,963
General and administrative	10	24,262	28,180	56,342	57,303
Depletion, depreciation, amortization and accretion		137,403	148,656	269,753	280,836
Asset impairment	5	497,247	–	764,858	–
Interest	11	16,121	16,522	33,154	31,701
Foreign exchange (gain)/loss	12	(27,656)	(7,225)	76,546	(5,756)
Other expense/(income)		(85)	(360)	8,527	2,552
		766,274	314,395	1,453,185	617,320
Income/(loss) before taxes		(534,295)	56,461	(965,848)	128,679
Current income tax expense/(recovery)	13	(102)	3,797	(39)	11,475
Deferred income tax expense/(recovery)	13	(221,649)	12,707	(360,059)	37,210
Net Income/(Loss)		$ (312,544)	$ 39,957	$ (605,750)	$ 79,994
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		(30,490)	(43,414)	146,269	2,230
Other Comprehensive Income/(Loss)		(30,490)	(43,414)	146,269	4,588
Total Comprehensive Income/(Loss)		$ (343,034)	$ (3,457)	$ (459,481)	$ 84,582
Net income/(loss) per share					
Basic	14	$ (1.52)	$ 0.20	$ (2.94)	$ 0.39
Diluted	14	$ (1.52)	$ 0.19	$ (2.94)	$ 0.39

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Changes in Shareholders' Equity

Six months ended June 30 (CDN$ thousands) unaudited	**2015**	**2014**
Share Capital		
Balance, beginning of year	$ 3,120,002	$ 3,061,839
Stock Option Plan – cash	3,205	19,193
Share-based compensation – settled	3,094	–
Stock Option Plan – exercised	267	3,683
Stock Dividend Plan	–	17,487
Balance, end of period	$ 3,126,568	$ 3,102,202
Paid-in Capital		
Balance, beginning of year	$ 46,906	$ 38,398
Share-based compensation – settled	(3,094)	–
Stock Option Plan – exercised	(267)	(3,683)
Share-based compensation – non-cash	9,561	6,494
Balance, end of period	$ 53,106	$ 41,209
Accumulated Deficit		
Balance, beginning of year	$ (1,039,260)	$ (1,117,238)
Net income/(loss)	(605,750)	79,994
Dividends	(78,294)	(110,149)
Balance, end of period	$ (1,723,304)	$ (1,147,393)
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	146,269	2,230
Balance, end of period	$ 241,747	$ (46,109)
Total Shareholders' Equity	$ 1,698,117	$ 1,949,909

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Note	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Operating Activities					
Net income/(loss)		$ (312,544)	$ 39,957	$ (605,750)	$ 79,994
Non-cash items add/(deduct):					
Depletion, depreciation, amortization and accretion		137,403	148,656	269,753	280,836
Asset impairment	5	497,247	–	764,858	–
Changes in fair value of derivative instruments	15	73,738	130	161,237	6,939
Deferred income tax expense/(recovery)	13	(221,649)	12,707	(360,059)	37,210
Foreign exchange (gain)/loss on debt and working capital	12	(18,590)	(9,052)	69,424	1,935
Share-based compensation	14	4,591	3,542	9,561	6,494
Amortization of debt issue costs		240	247	480	493
Asset divestments (gain)/loss		–	–	–	2,798
Derivative settlement on senior notes		–	17,024	(39,904)	17,024
Asset retirement obligation expenditures	8	(2,569)	(4,240)	(6,459)	(8,532)
Changes in non-cash operating working capital	17	(22,771)	19,535	3,051	(56,275)
Cash flow from operating activities		135,096	228,506	266,192	368,916
Financing Activities					
Proceeds from the issuance of shares	14	634	13,055	3,205	19,193
Cash dividends	14	(30,935)	(50,508)	(78,294)	(92,662)
Change in bank credit facility		(45,386)	107,280	434	76,710
Repayment of senior notes		(88,897)	(37,898)	(88,897)	(37,898)
Derivative settlement on senior notes		–	(17,024)	39,904	(17,024)
Changes in non-cash financing working capital		(15)	103	(8,222)	204
Cash flow from financing activities		(164,599)	15,008	(131,870)	(51,477)
Investing Activities					
Capital and office expenditures		(149,439)	(205,623)	(317,327)	(423,816)
Property and land acquisitions		1,011	(3,231)	1,247	(13,200)
Property dispositions		187,801	(525)	191,513	116,700
Sale of marketable securities		–	–	–	13,300
Changes in non-cash investing working capital		(12,148)	(35,482)	(11,217)	(10,805)
Cash flow from investing activities		27,225	(244,861)	(135,784)	(317,821)
Effect of exchange rate changes on cash		677	(2,392)	428	(610)
Change in cash		(1,601)	(3,739)	(1,034)	(992)
Cash, beginning of period		2,603	5,737	2,036	2,990
Cash, end of period		$ 1,002	$ 1,998	$ 1,002	$ 1,998

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 August 6, 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 and six months ended June 30, 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)	June 30, 2015	December 31, 2014
Accrued receivables	$ 130,839	$ 136,949
Accounts receivable – trade	26,389	41,618
Current income tax receivable	6,798	23,900
Allowance for doubtful accounts	(2,742)	(2,722)
Total accounts receivable	$ 161,284	$ 199,745

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

As at June 30, 2015 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 12,945,978	$ (11,093,177)	$ 1,852,801
Other capital assets	101,274	(81,009)	20,265
Total PP&E	$ 13,047,252	$ (11,174,186)	$ 1,873,066

As at December 31, 2014 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	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

($ thousands)	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
Oil and natural gas properties:				
Canada cost centre	$ 28,100	$ –	$ 28,100	$ –
U.S. cost centre	469,147	–	736,758	–
Total impairment expense	$ 497,247	$ –	$ 764,858	$ –

The impairments for the three and six months ended June 30, 2015 were due to lower 12-month average trailing crude oil and natural gas prices.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from June 30, 2014 through June 30, 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
Q2 2015	$ 71.75	$ 1.16	$ 75.83	$ 3.42	$ 3.33
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

6) ACCOUNTS PAYABLE

($ thousands)	June 30, 2015	December 31, 2014
Accrued payables	$ 230,815	$ 239,773
Accounts payable – trade	86,228	111,233
Total accounts payable	$ 317,043	$ 351,006

7) DEBT

($ thousands)	June 30, 2015	December 31, 2014
Current:		
Senior notes	$ 13,472	$ 98,933
	13,472	98,933
Long-term:		
Bank credit facility	$ 80,351	$ 79,917
Senior notes	1,027,859	958,080
	1,108,210	1,037,997
Total debt	$ 1,121,682	$ 1,136,930

8) ASSET RETIREMENT OBLIGATION

Enerplus has estimated the present value of its asset retirement obligation to be $282.5 million at June 30, 2015 compared to $288.7 million at December 31, 2014 based on a total undiscounted liability of $698.2 million and $730.9 million, respectively. The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.95% (December 31, 2014 – 5.92%).

($ thousands)	Six months ended June 30, 2015	Year ended December 31, 2014
Balance, beginning of year	$ 288,692	$ 291,761
Change in estimates	4,779	4,378
Property acquisitions and development activity	586	1,778
Dispositions	(13,411)	(4,313)
Settlements	(6,459)	(19,409)
Accretion expense	8,287	14,497
Balance, end of period	$ 282,474	$ 288,692

9) OIL AND NATURAL GAS SALES

	Three months ended June 30		Six months ended June 30	
($ thousands)	2015	2014	2015	2014
Oil and natural gas sales	$ 298,433	$ 504,551	$ 542,510	$ 999,575
Royalties[1]	(46,703)	(89,626)	(85,820)	(176,910)
Oil and natural gas sales, net of royalties	$ 251,730	$ 414,925	$ 456,690	$ 822,665

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

10) GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended June 30		Six months ended June 30	
($ thousands)	2015	2014	2015	2014
General and administrative expense	$ 19,872	$ 18,672	$ 41,307	$ 39,201
Share-based compensation expense	4,390	9,508	15,035	18,102
General and administrative expense	$ 24,262	$ 28,180	$ 56,342	$ 57,303

11) INTEREST EXPENSE

	Three months ended June 30		Six months ended June 30	
($ thousands)	2015	2014	2015	2014
Realized:				
Interest on bank debt and senior notes	$ 15,881	$ 15,962	$ 32,674	$ 30,628
Unrealized:				
Cross currency interest rate swap (gain)/loss	–	313	–	580
Amortization of debt issue costs	240	247	480	493
Interest expense	$ 16,121	$ 16,522	$ 33,154	$ 31,701

12) FOREIGN EXCHANGE

($ thousands)	Three months ended June 30 2015	Three months ended June 30 2014	Six months ended June 30 2015	Six months ended June 30 2014
Realized:				
Foreign exchange (gain)/loss	$ 8,402	$ 16,626	$ (27,172)	$ 16,676
Unrealized:				
Translation of U.S. dollar debt and working capital (gain)/loss	(18,590)	(9,052)	69,424	1,935
Cross currency interest rate swap (gain)/loss	–	(14,885)	–	(16,130)
Foreign exchange derivatives (gain)/loss	(17,468)	86	34,294	(8,237)
Foreign exchange (gain)/loss	$ (27,656)	$ (7,225)	$ 76,546	$ (5,756)

13) INCOME TAXES

($ thousands)	Three months ended June 30 2015	Three months ended June 30 2014	Six months ended June 30 2015	Six months ended June 30 2014
Current tax expense/(recovery)				
Canada	$ (400)	$ (190)	$ (400)	$ (374)
United States	298	3,987	361	11,849
Current tax expense/(recovery)	(102)	3,797	(39)	11,475
Deferred tax expense/(recovery)				
Canada	$ (27,676)	$ (7,005)	$ (36,939)	$ (5,318)
United States	(193,973)	19,712	(323,120)	42,528
Deferred tax expense/(recovery)	(221,649)	12,707	(360,059)	37,210
Income tax expense/(recovery)	$ (221,751)	$ 16,504	$ (360,098)	$ 48,685

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

	Six months ended June 30 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	234	3,205	1,944	31,350
Non-cash:				
Share-based compensation – settled	258	3,094	–	–
Stock Option Plan – exercised	–	267	–	4,978
Stock Dividend Plan(1)	–	–	1,030	21,835
Balance, end of period	206,224	$ 3,126,568	205,732	$ 3,120,002

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

b) Dividends

($ thousands)	Three months ended June 30 2015	Three months ended June 30 2014	Six months ended June 30 2015	Six months ended June 30 2014
Cash dividends	$ 30,935	$ 50,508	$ 78,294	$ 92,662
Stock dividends[1]	–	4,706	–	17,487
Dividends to shareholders	$ 30,935	$ 55,214	$ 78,294	$ 110,149

(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 June 30 2015	Three months ended June 30 2014	Six months ended June 30 2015	Six months ended June 30 2014
Cash:				
Long-term incentive plans expense	$ (1,233)	$ 10,648	$ 6,041	$ 17,512
Non-cash:				
Long-term incentive plans expense	4,453	2,856	9,035	3,691
Stock option plan expense	138	686	526	2,803
Equity swap (gain)/loss	1,032	(4,682)	(567)	(5,904)
Share-based compensation expense	$ 4,390	$ 9,508	$ 15,035	$ 18,102

(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 six months ended June 30, 2015:

For the six months ended June 30, 2015 (thousands of units)	Cash-settled LTI plans PSU	Cash-settled LTI plans RSU	DSU	Equity-settled LTI Plans PSU	Equity-settled LTI Plans RSU	Total
Balance, beginning of year	406	398	122	510	775	2,211
Granted	–	–	77	948	1,389	2,414
Vested	(120)	(214)	(19)	–	(258)	(611)
Forfeited	(10)	(27)	–	(13)	(109)	(159)
Balance, end of period	276	157	180	1,445	1,797	3,855

Cash-settled LTI Plans

For the three and six months ended June 30, 2015 the Company recorded a cash share-based compensation recovery of $1.2 million and an expense of $6.0 million, respectively (June 30, 2014 – $10.6 million expense and $17.5 million expense). For the three and six months ended June 30, 2015 the Company made cash payments of nil and $5.6 million, respectively, related to its cash-settled plans (June 30, 2014 – $0.3 million and $11.8 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 June 30, 2015 ($ thousands, except for years)	**PSU**[1]	**RSU**	**DSU**	**Total**
Cumulative recognized share-based compensation expense	$ 10,103	$ 2,326	$ 2,329	$ 14,758
Unrecognized share-based compensation expense	1,215	302	–	1,517
Intrinsic value	$ 11,318	$ 2,628	$ 2,329	$ 16,275
Weighted-average remaining contractual term (years)	0.5	0.4	–	

(1) Includes estimated performance multipliers.

Equity-settled LTI Plans

For the three and six months ended June 30, 2015 the Company recorded non-cash share-based compensation expense of $4.5 million and $9.0 million, respectively (2014 – $2.9 million and $3.7 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 June 30, 2015 ($ thousands, except for years)	**PSU**[1]	**RSU**	**Total**
Cumulative recognized share-based compensation expense	$ 5,099	$ 13,284	$ 18,383
Unrecognized share-based compensation expense	10,997	15,534	26,531
Fair value	$ 16,096	$ 28,818	$ 44,914
Weighted-average remaining contractual term (years)	2.1	1.6	

(1) Includes estimated performance multipliers.

(ii) Stock Option Plan

The Company did not grant any stock options for the three and six months ended June 30, 2015. The following table summarizes the stock option plan activity for the period ended June 30, 2015:

Period ended June 30, 2015	**Number of Options** (thousands)	**Weighted Average Exercise Price**
Options outstanding, beginning of year	10,368	$ 18.65
Granted	–	–
Exercised	(234)	13.71
Forfeited	(653)	20.01
Options outstanding, end of period	9,481	$ 18.68
Options exercisable, end of period	7,489	$ 19.96

At June 30, 2015 7,489,000 options were exercisable at a weighted average reduced exercise price of $19.96 with a weighted average remaining contractual term of 3.7 years, giving an aggregate intrinsic value of nil (2014 – $36.7 million). The intrinsic value of options exercised for the three and six months ended June 30, 2015 was $0.1 million and $0.2 million, respectively (June 30, 2014 – $5.2 million and $8.1 million).

At June 30, 2015 the total share-based compensation expense related to non-vested options not yet recognized was $0.4 million. The expense is expected to be recognized in net income over a weighted-average period of 0.7 years.

d) Paid-in Capital

The following table summarizes the paid-in capital activity for the six months ended June 30, 2015 and the year ended December 31, 2014:

($ thousands)	Six months ended June 30, 2015	Year Ended December 31, 2014
Balance, beginning of year	$ 46,906	$ 38,398
Share-based compensation – settled	(3,094)	–
Stock Option Plan – exercised	(267)	(4,978)
Share-based compensation – non-cash	9,561	13,486
Balance, end of period	$ 53,106	$ 46,906

e) Basic and Diluted Earnings Per Share

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

	Three months ended June 30,		Six months ended June 30,	
(thousands, except per share amounts)	2015	2014	2015	2014
Net income/(loss)	$ (312,544)	$ 39,957	$ (605,750)	$ 79,994
Weighted average shares outstanding – Basic	206,208	204,158	206,028	203,671
Dilutive impact of share-based compensation(1)	–	4,364	–	3,892
Weighted average shares outstanding – Diluted	206,208	208,522	206,028	207,563
Net income/(loss) per share				
Basic	$ (1.52)	$ 0.20	$ (2.94)	$ 0.39
Diluted(1)	(1.52)	0.19	(2.94)	0.39

(1) For the three and six months ended June 30, 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 June 30, 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 June 30, 2015 senior notes had a carrying value of $1,041.3 million and a fair value of $1,121.0 million (December 31, 2014 – $1,057.0 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 and six months ended June 30, 2015 and 2014.

	Three months ended June 30,		Six months ended June 30,		
Gain/(Loss) ($ thousands)	**2015**	**2014**	**2015**	**2014**	**Income Statement Presentation**
Cross Currency Interest Rate Swap					
Interest	$ –	$ (313)	$ –	$ (580)	Interest expense
Foreign Exchange	–	14,885	–	16,130	Foreign exchange
Foreign Exchange Derivatives	17,468	(86)	(34,294)	8,237	Foreign exchange
Electricity Swaps	2,642	228	1,715	182	Operating expense
Equity Swaps	(1,032)	4,682	567	5,904	General and administrative expense
Commodity Derivative Instruments:					
Oil	(71,085)	(24,810)	(107,044)	(34,203)	Commodity derivative
Gas	(21,731)	5,284	(22,181)	(2,609)	instruments
Total	$ (73,738)	$ (130)	$ (161,237)	$ (6,939)	

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

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2015**	**2014**	**2015**	**2014**
Change in fair value gain/(loss)	$ (92,816)	$ (19,526)	$ (129,225)	$ (36,812)
Net realized cash gain/(loss)	73,065	(24,543)	159,872	(39,854)
Commodity derivative instruments gain/(loss)	$ (19,751)	$ (44,069)	$ 30,647	$ (76,666)

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

	June 30, 2015			December 31, 2014			
	Assets		Liabilities	Assets		Liabilities	
($ thousands)	Current	Long-term	Current	Current	Long-term	Current	Long-term
Foreign Exchange Derivatives	$ 2,519	$ –	$ 14,966	$ 1,616	$ 28,665	$ 8,434	$ –
Electricity Swaps	347	–	–	–	–	1,368	–
Equity Swaps	–	–	2,853	–	–	1,024	2,396
Commodity Derivative Instruments:							
Oil	53,697	6,446	–	167,187	–	–	–
Gas	27,054	–	–	46,903	2,332	–	–
Total	$ 83,617	$ 6,446	$ 17,819	$ 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 the Corporation's price risk management positions at July 22, 2015:

Crude Oil Instruments:

Instrument Type[1]	bbls/day	US$/bbl
Jul 1, 2015 – Sep 30, 2015		
WTI Swap	8,000	93.86
WTI Purchased Call	4,000	93.00
WTI Sold Put	4,000	62.23
WCS Differential Swap	4,000	(16.61)
MSW Differential Swap	1,000	(3.50)
Oct 1, 2015 – Dec 31, 2015		
WTI Swap	12,500	82.10
WTI Purchased Put	2,000	63.00
WTI Sold Call	2,000	70.00
WTI Purchased Call	4,000	93.00
WTI Sold Put	6,000	57.49
WCS Differential Swap	4,000	(16.61)
MSW Differential Swap	1,000	(3.50)
Jan 1, 2016 – Jun 30, 2016		
WTI Swap	3,000	64.28
WTI Purchased Put	8,000	64.38
WTI Sold Call	8,000	79.38
WTI Sold Put	8,000	50.13
WCS Differential Swap	2,000	(14.50)
Jul 1, 2016 – Dec 31, 2016		
WTI Purchased Put	11,000	64.35
WTI Sold Call	11,000	80.09
WTI Sold Put	11,000	49.34
WCS Differential Swap	2,000	(14.50)

(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
Jul 1, 2015 – Sep 30, 2015		
NYMEX Swap	155.0	3.73
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
Jan 1, 2016 – Dec 31, 2016		
NYMEX Purchased Put	25.0	3.00
NYMEX Sold Put	25.0	2.50
NYMEX Sold Call	25.0	3.75

Electricity Instruments:

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

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

Physical Contracts:

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

Foreign Exchange Risk:

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

Foreign Exchange Derivatives:

During 2015 Enerplus entered into foreign exchange forward rate swaps for July through December 2015 to buy US$6 million per month at an average US$/CDN$ exchange rate of 1.20 to partially mitigate losses on the foreign exchange collars entered into in 2014.

During 2014 Enerplus entered into foreign exchange collars to protect a portion of its foreign exchange exposure on U.S. dollar denominated oil and gas sales with upside participation in the event the Canadian dollar weakened. As of June 30, 2015 we have US$24 million per month hedged for the remainder of 2015 at an average USD/CDN floor of 1.1088, a ceiling of 1.1845 and a conditional ceiling of 1.1263.

During 2011 Enerplus entered into foreign exchange swaps on US$175.0 million of notional debt at approximately par. During 2015 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).

During 2007 Enerplus entered in 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.

Interest Rate Risk:

At June 30, 2015 approximately 93% of Enerplus' debt was based on fixed interest rates and 7% was based on floating interest rates. At June 30, 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 figure settlement cost on 524,000 shares at weighted average price of $16.51 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 June 30, 2015 approximately 63% of Enerplus' marketing receivables were with companies considered investment grade.

At June 30, 2015 approximately $4.7 million or 3% 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 of 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 uncollectable the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at June 30, 2015 was $2.7 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 June 30, 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

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2015	2014	2015	2014
Accounts receivable	$ (5,371)	$ 12,292	$ 18,696	$ (19,877)
Other current assets	(10,079)	(379)	(14,877)	544
Accounts payable	(7,321)	7,622	(768)	(36,942)
	$ (22,771)	$ 19,535	$ 3,051	$ (56,275)

b) Other

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2015	2014	2015	2014
Income taxes paid/(received)	$ 148	$ 18,521	$ (19,197)	$ 18,387
Interest paid	$ 25,936	$ 26,305	$ 32,418	$ 28,688

BOARD OF DIRECTORS

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

David H. Barr(9)(12)
Corporate Director
The Woodlands, Texas

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

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

Hilary A. Foulkes(5)(9)(11)
Corporate Director
Calgary, Alberta

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

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

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

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

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

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

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas
President & Chief Executive Officer

Ray J. Daniels
Senior Vice President, Operations

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

Robert J. Waters
Senior Vice President & Chief Financial Officer

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

John E. Hoffman
Vice President, Canadian Operations

Jodine J. Jenson Labrie
Vice President, Finance

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

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

Edward L. McLaughlin
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

LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Calgary, Alberta

AUDITORS

Deloitte LLP
Calgary, Alberta

TRANSFER AGENT

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

U.S. CO-TRANSFER AGENT

Computershare Trust Company, N.A.
Golden, Colorado

INDEPENDENT RESERVE ENGINEERS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates,Inc.
Dallas, Texas

STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

Toronto Stock Exchange: ERF
New York Stock Exchange: ERF

U.S.OFFICE

950 17th Street, Suite 2200
Denver, Colorado 80202

Telephone: 720.279.5500
Fax: 720.279.5550

ABBREVIATIONS

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

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.

ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE

Toll Free 1.800.319.6462
investorrelations@enerplus.com

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

enerPLUS

www.enerplus.com