FINANCIAL SUMMARY 2016

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2016 FINANCIAL SUMMARY

SELECTED FINANCIAL RESULTS	Three months ended December 31, 2016	Three months ended December 31, 2015	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015
Financial (000's)				
Adjusted Funds Flow[4]	$ 107,730	$ 102,674	$ 305,605	$ 493,101
Dividends to Shareholders	7,214	22,717	35,439	131,955
Net Income/(Loss)	840,325	(624,987)	397,416	(1,523,403)
Debt Outstanding, net of Cash and Restricted Cash	375,520	1,216,184	375,520	1,216,184
Capital Spending	57,462	89,490	209,135	493,403
Property and Land Acquisitions	118,452	8,794	126,126	9,552
Property Divestments	389,750	83,236	670,364	286,614
Debt to Adjusted Funds Flow Ratio[4]	1.2x	2.5x	1.2x	2.5x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ 3.49	$ (3.03)	$ 1.75	$ (7.39)
Net Income/(Loss) - Diluted	3.43	(3.03)	1.72	(7.39)
Weighted Average Number of Shares Outstanding (000's)	240,483	206,517	226,530	206,205
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 32.81	$ 23.81	$ 25.88	$ 27.07
Royalties and Production Taxes	(7.60)	(4.75)	(5.77)	(5.63)
Commodity Derivative Instruments	1.12	7.50	2.36	7.40
Cash Operating Expenses	(7.22)	(8.68)	(7.31)	(8.75)
Transportation Costs	(3.44)	(2.98)	(3.14)	(2.95)
General and Administrative Expenses	(1.63)	(1.75)	(1.75)	(2.09)
Cash Share-Based Compensation	(0.17)	0.16	(0.09)	(0.02)
Interest, Foreign Exchange and Other Expenses	(0.97)	(2.94)	(1.28)	(2.78)
Current Tax Recovery	0.26	0.07	0.07	0.43
Adjusted Funds Flow[4]	$ 13.16	$ 10.44	$ 8.97	$ 12.68

SELECTED OPERATING RESULTS	Three months ended December 31, 2016	Three months ended December 31, 2015	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015
Average Daily Production[2]				
Crude Oil (bbls/day)	37,128	41,135	38,353	41,639
Natural Gas Liquids (bbls/day)	4,413	5,092	4,903	4,763
Natural Gas (Mcf/day)	284,515	364,065	299,214	360,733
Total (BOE/day)	88,960	106,905	93,125	106,524
% Crude Oil and Natural Gas Liquids	47%	43%	46%	44%
Average Selling Price[2][3]				
Crude Oil (per bbl)	$ 53.91	$ 43.04	$ 44.84	$ 48.43
Natural Gas Liquids (per bbl)	21.31	16.61	15.29	18.06
Natural Gas (per Mcf)	2.89	1.89	2.06	2.15
Net Wells Drilled	5	2	25	46

(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 December 31, 2016	Three months ended December 31, 2015	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015
WTI crude oil (US$/bbl)	$ 49.29	$ 42.18	$ 43.32	$ 48.80
AECO natural gas – monthly index (CDN$/Mcf)	2.81	2.65	2.09	2.77
AECO natural gas – daily index (CDN$/Mcf)	3.09	2.47	2.16	2.69
NYMEX natural gas – last day (US$/Mcf)	2.98	2.27	2.46	2.66
US/CDN average exchange rate	1.33	1.34	1.32	1.28

Share Trading Summary For the twelve months ended December 31, 2016	CDN[1] – ERF (CDN$)	U.S.[2] – ERF (US$)
High	$ 13.55	$ 10.33
Low	$ 2.68	$ 1.84
Close	$ 12.74	$ 9.48

(1) TSX and other Canadian trading data combined.
(2) NYSE and other U.S. trading data combined.

2016 Dividends per Share	CDN$	US$[1]
First Quarter Total	$ 0.09	$ 0.07
Second Quarter Total	$ 0.03	$ 0.02
Third Quarter Total	$ 0.03	$ 0.02
Fourth Quarter Total	$ 0.03	$ 0.02
Total Year to Date	$ 0.18	$ 0.13

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

2016 HIGHLIGHTS

Financial and Operational Highlights

- Fourth quarter 2016 production averaged 88,960 BOE per day, bringing annual average 2016 production to 93,125 BOE per day, in line with guidance of 93,000 BOE per day. Fourth quarter 2016 crude oil and natural gas liquids production averaged 41,541 barrels per day, impacted by severe weather in North Dakota during the quarter. Annual average 2016 liquids production was 43,256 barrels per day, within the guidance range of 43,000 to 44,000 barrels per day.

- Enerplus realized strong value from its non-core divestments in 2016, selling 13,500 BOE per day (60% natural gas) of production for aggregate proceeds of $670.4 million.

- The Company reported fourth quarter 2016 net income of $840.3 million, or $3.43 per diluted share. Net income was impacted by a gain on the sale of the Company's non-operated North Dakota properties of $339.4 million, and a non-cash deferred tax recovery of $567.8 million primarily as a result of the reversal of a portion of the valuation allowance on the Company's deferred tax asset. For the year ended December 31, 2016, Enerplus reported net income of $397.4 million, or $1.72 per diluted share, compared with a net loss of $1,523.4 million, or $7.39 per share for the comparable 2015 period.

- Enerplus generated fourth quarter 2016 adjusted funds flow of $107.7 million, an increase of 34% from the previous quarter as a result of stronger commodity prices in the fourth quarter. The Company generated full year 2016 adjusted funds flow of $305.6 million, down 38% from the comparable 2015 period due to lower average commodity prices and lower hedging gains in 2016.

- Enerplus delivered strong operating cost performance in 2016 reflecting efficiency improvements and the divestment of higher cost properties. Fourth quarter operating expenses were $7.15 per BOE, a reduction of 18% compared to the same period in 2015. Full year 2016 operating expenses were $7.27 per BOE, a reduction of 17% compared to 2015.

- Fourth quarter 2016 cash G&A expenses were $1.63 per BOE, a reduction of 7% compared to the same period in 2015. Full year 2016 cash G&A expenses were $1.75 per BOE, a reduction of 16% compared to 2015. Enerplus' lower G&A cost structure is, in part, a result of a reduction in staffing levels related to non-core asset divestments.

- Transportation expense in the fourth quarter of 2016 was $3.44 per BOE, up slightly from the previous quarter. Full year 2016 transportation expense was $3.14 per BOE, a 6% increase from the prior year period.

- Capital spending in the fourth quarter of 2016 was $57.5 million, with approximately 72% allocated to North Dakota. Full year 2016 capital spending totaled $209.1 million, slightly below annual 2016 guidance of $215.0 million.

- Enerplus significantly strengthened its balance sheet during 2016 having reduced its total debt net of cash and restricted cash by 69%, or $840.7 million, over the twelve-month period. Total debt net of cash and restricted cash at December 31, 2016 was $375.5 million, and was comprised of $23.2 million of bank indebtedness and $745.6 million of senior notes less $393.3 million in cash, including $392.0 million in restricted cash. The restricted cash balance reflects proceeds from the sale of the Company's non-operated North Dakota properties which were placed in escrow in order to facilitate possible future like-kind transactions in accordance with U.S. federal tax regulations. Net debt to adjusted funds flow at year-end was 1.2 times.

Reserves Highlights

- Replaced 126% of 2016 production, adding 42.6 MMBOE (42% crude oil and natural gas liquids) of proved plus probable ("2P") reserves from development activities (including revisions).

- Material reserves growth was realized in Enerplus' North Dakota and Marcellus assets. The Company replaced 207% of 2016 North Dakota production, excluding production from Enerplus' non-operated North Dakota assets which were sold at the end of 2016, adding 17.5 MMBOE of 2P reserves (including revisions). The Company also replaced 175% of 2016 Marcellus production, adding 125.0 Bcf of 2P reserves (including revisions).

- Finding and development ("F&D") costs for proved developed producing ("PDP") reserves decreased by 60% to $4.77 per BOE for 2016, generating a PDP reserves recycle ratio of 2.0 times based on a 2016 operating netback of $9.66 per BOE. Enerplus' three-year average PDP reserves F&D cost was $10.37 per BOE.

- F&D costs for 2P reserves decreased by 43% to $4.82 per BOE for 2016, including future development costs (“FDC”), generating a 2P reserves recycle ratio of 2.0 times. Enerplus’ three-year average 2P reserves F&D cost, including FDC, was $8.11 per BOE.

- Enerplus sold various non-core properties in 2016 representing 37.3 MMBOE of 2P reserves at an average value of $20.38 per BOE. Total 2P reserves, net of divestments, were 382.5 MMBOE at year-end 2016, representing a 6% decrease from year-end 2015. Excluding acquisitions and divestments, 2P reserves increased by 2% in 2016.

- 2P reserves were comprised of 51% crude oil and natural gas liquids and 49% natural gas at year-end 2016.

- Total proved reserves account for 70% of 2P reserves. PDP reserves represent 71% of total proved reserves and 50% of 2P reserves.

Management's Discussion and Analysis ("MD&A")

The following discussion and analysis of financial results is dated February 23, 2017 and is to be read in conjunction with the audited Consolidated Financial Statements (the "Financial Statements") of Enerplus Corporation ("Enerplus" or the "Company"), as at December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014.

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" at the end of this MD&A for further information.

BASIS OF PRESENTATION

The Financial Statements and notes have been prepared in accordance with U.S. GAAP, including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Financial Statements. Certain prior period amounts have been restated to conform with current period presentation.

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

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

The following table provides a reconciliation of our production volumes:

	Year ended December 31,		
Average Daily Production Volumes	**2016**	**2015**	**2014**
Company interest production volumes			
Crude oil (bbls/day)	38,353	41,639	40,208
Natural gas liquids (bbls/day)	4,903	4,763	3,565
Natural gas (Mcf/day)	299,214	360,733	356,142
Company interest production volumes (BOE/day)	93,125	106,524	103,130
Royalty volumes			
Crude oil (bbls/day)	7,198	7,471	7,731
Natural gas liquids (bbls/day)	932	971	775
Natural gas (Mcf/day)	50,270	59,077	55,114
Royalty volumes (BOE/day)	16,508	18,288	17,692
Net production volumes			
Crude oil (bbls/day)	31,155	34,168	32,477
Natural gas liquids (bbls/day)	3,971	3,792	2,790
Natural gas (Mcf/day)	248,944	301,656	301,028
Net production volumes (BOE/day)	76,617	88,236	85,438

2016 FOURTH QUARTER OVERVIEW

Fourth quarter production averaged 88,960 BOE/day, in line with our target of 89,000 BOE/day, and a decrease of 3,117 BOE/day compared to third quarter production of 92,077 BOE/day. In the U.S. production during the fourth quarter was impacted by approximately 1,700 BOE/day of price related curtailments in the Marcellus and fewer on-streams in North Dakota along with severe winter weather. Canadian production was consistent with the prior quarter, with production from our November asset acquisition of a Canadian waterflood property offsetting price related shut-ins and minor non-core asset divestments. Operating costs increased somewhat in the fourth quarter, to $58.5 million or $7.15/BOE from $56.2 million or $6.64/BOE in the third quarter, due to additional weather related costs in December.

We reported net income of $840.3 million and adjusted funds flow of $107.7 million in the fourth quarter compared to a net loss of $100.7 million and adjusted funds flow of $80.1 million in the third quarter. Both net income and adjusted funds flow benefited from a $29.1 million or 15% increase in net oil and natural gas sales compared to the third quarter, with improved pricing offsetting the impact of lower production volumes. Net income also increased as a result of a non-cash deferred tax recovery of $567.8 million due to the reversal of a portion of the valuation allowance on our deferred tax asset and a $339.4 million gain on the sale of non-operated North Dakota properties.

On November 15, 2016, we closed the previously announced purchase of a Canadian waterflood property for proceeds of $110.3 million.

On December 30, 2016, we closed the previously announced sale of our non-operated North Dakota properties with production of approximately 5,000 BOE/day for proceeds of $392.0 million.

Selected Fourth Quarter Canadian and U.S. Financial Results

	Three months ended December 31, 2016			Three months ended December 31, 2015		
(millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	12,417	24,711	37,128	13,790	27,345	41,135
Natural gas liquids (bbls/day)	1,160	3,253	4,413	1,771	3,321	5,092
Natural gas (Mcf/day)	68,437	216,078	284,515	135,898	228,167	364,065
Total average daily production (BOE/day)	24,983	63,977	88,960	38,210	68,695	106,905
Pricing(2)						
Crude oil (per bbl)	$ 48.44	$ 56.66	$ 53.91	$ 38.11	$ 45.53	$ 43.04
Natural gas liquids (per bbl)	36.33	15.96	21.31	28.77	10.13	16.61
Natural gas (per Mcf)	3.13	2.82	2.89	2.46	1.55	1.89
Capital Expenditures						
Capital spending	$ 10.2	$ 47.3	$ 57.5	$ 26.8	$ 62.7	$ 89.5
Acquisitions	111.2	7.2	118.4	0.7	8.1	8.8
Divestments	(1.5)	(388.3)	(389.8)	0.9	(84.1)	(83.2)
Netback(3) Before Hedging						
Oil and natural gas sales	$ 78.9	$ 189.7	$ 268.6	$ 84.0	$ 150.2	$ 234.2
Royalties	(11.0)	(40.1)	(51.1)	(9.0)	(25.8)	(34.8)
Production taxes	(0.4)	(10.6)	(11.0)	(1.5)	(10.5)	(12.0)
Cash operating expenses	(30.7)	(28.4)	(59.1)	(54.4)	(30.9)	(85.3)
Transportation costs	(3.2)	(25.0)	(28.2)	(5.2)	(24.1)	(29.3)
Netback before hedging	$ 33.6	$ 85.6	$ 119.2	$ 13.9	$ 58.9	$ 72.8
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 33.0	$ —	$ 33.0	$ (31.1)	$ —	$ (31.1)
General and administrative expense(4)	21.0	7.0	28.0	10.4	8.1	18.5
Current income tax recovery	—	(2.1)	(2.1)	(0.4)	(0.3)	(0.7)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See "Non-GAAP Measures" section in this MD&A.
(4) Includes share-based compensation.

Comparing the fourth quarter of 2016 with the same period in 2015:

- Average daily production was 88,960 BOE/day, down 17% or approximately 17,945 BOE/day from 106,905 BOE/day in 2015 primarily due to our non-core Canadian asset divestments and lower capital spending.

- Despite a significant reduction in capital spending, U.S. production declined only modestly over the period as a result of strong well performance. This was offset somewhat by the divestment of 1,000 BOE/day of our non-operated North Dakota properties during the fourth quarter of 2015. U.S. crude oil production decreased 10% or 2,634 BOE/day from the fourth quarter of 2016 to the fourth quarter of 2015, while natural gas production decreased 5% or 2,015 BOE/day over the same period.

- Capital spending decreased to $57.5 million compared to $89.5 million in the fourth quarter of 2015. The majority of our capital investment in the fourth quarter was focused on our core areas, with spending of $41.1 million on our North Dakota crude oil properties, $10.2 million on our Canadian crude oil waterflood properties and $4.2 million on our Marcellus natural gas properties.

- Operating expenses decreased to $58.5 million ($7.15/BOE) compared to $85.6 million ($8.71/BOE) in the fourth quarter of 2015 as a result of ongoing cost efficiencies and the divestment of higher operating cost Canadian properties throughout 2016.

- Cash general and administrative ("G&A") expenses decreased to $13.4 million ($1.63/BOE) compared to $17.2 million ($1.75/BOE) in 2015 due to reductions in staffing levels and the success of our ongoing cost saving initiatives.

- We reported net income of $840.3 million in the fourth quarter of 2016 compared to a net loss of $625.0 million in the fourth quarter of 2015. The improvement year over year was primarily the result of a non-cash deferred tax recovery of $567.8 million due to the reversal of a portion of our valuation allowance on our deferred tax asset, compared to a non-cash deferred tax provision of $294.4 million on our deferred tax asset in the same period of 2015. Net income also benefitted from a gain of $339.4 million on the sale of our non-operated North Dakota property and a $221.0 million decrease in the non-cash impairment charge on our crude oil and natural gas assets compared to the fourth quarter of 2015.

- Adjusted funds flow increased to $107.7 million compared to $102.7 million in the fourth quarter of 2015. The increase in adjusted funds flow was a result of significantly higher commodity prices, which were offset in part by lower production volumes and a $64.1 million decrease in cash gains on commodity hedges.

2016 OVERVIEW AND 2017 OUTLOOK

Summary of Guidance and Results	Original 2016 Guidance	Revised 2016 Guidance	2016 Results	2017 Guidance
Capital spending ($ millions)	$200	$215	$209	$450
Average annual production (BOE/day)	90,000 - 94,000	93,000	93,125	86,000 – 90,000
Crude oil and natural gas liquids volumes (bbls/day)	43,000 - 45,000	43,000 - 44,000	43,256	40,000 – 43,000
Average royalty and production tax rate (% of oil and natural gas sales)	23%	22%	22%	23%
Operating expenses (per BOE)	$9.50	$7.50	$7.27	$7.85
Transportation costs (per BOE)	$3.30	$3.15	$3.14	$3.90
Cash G&A expenses (per BOE)	$2.10	$1.80	$1.75	$1.80

2016 Overview

We improved our financial position in 2016 despite the weakness and volatility in commodity prices. We achieved this through ongoing cost reductions, strong operational results, a disciplined capital program and a successful non-core asset divestment program.

Average annual production was 93,125 BOE/day, consistent with our guidance of 93,000 BOE/day. Crude oil and liquids volumes were 43,256 bbls/day, within our guidance range of 43,000 – 44,000 bbls/day.

Our capital spending for the year totaled $209.1 million, slightly below our guidance of $215 million due to weather related deferrals of spending in the fourth quarter.

Operating expenses and cash G&A expenses came in under our guidance, at $7.27/BOE and $1.75/BOE, respectively, compared to guidance of $7.50/BOE and $1.80/BOE, respectively. The outperformance was a result of our ongoing cost saving initiatives and our continued effort to focus our business through the sale of higher cost, non-core assets.

Net income for 2016 was $397.4 million, a significant increase from our net loss of $1,523.4 million in 2015 primarily due to a $1,051.3 million decrease in non-cash asset impairments, along with $578.5 million in realized gains on asset divestments and senior note prepayments.

Adjusted funds flow decreased 38% to $305.6 million in 2016 from $493.1 million in 2015. This was due to a $161.7 million decrease in net oil and gas sales over the period as a result of lower production volumes and weaker commodity prices, along with a $207.4 million decrease in realized gains on commodity hedges. These reductions were offset by significant cost savings in operating, interest and cash G&A expenses.

We continued to focus our portfolio during 2016, divesting of certain non-operated crude oil assets in the U.S. and lower margin crude oil and natural gas assets in Canada for aggregate proceeds of $670.4 million. These assets had associated production of approximately 13,500 BOE/day.

On May 31, 2016, we completed an equity financing of 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million net of issue costs).

Proceeds from both the asset divestments and equity financing were used to reduce our total debt, net of cash and restricted cash, by 69% or $840.7 million compared to the prior year. Net debt at December 31, 2016 was $375.5 million, comprised of $23.2 million of bank indebtedness and $745.6 million of senior notes less $393.3 million in cash and restricted cash. At December 31, 2016, we were approximately 3% drawn on our $800 million senior unsecured bank credit facility.

2017 Outlook

Our focus for 2017 is to deliver profitable growth and generate strong returns on capital while maintaining our balance sheet strength. Accordingly, we have increased our capital budget for 2017 to $450 million, with the majority directed to our North Dakota crude oil properties. We expect this spending level to generate significant liquids growth, with a 25% increase in liquids production from the beginning of 2017 to the fourth quarter of 2017, driven by 50% growth in our total North Dakota production over the same period.

Annual 2017 production is expected to average between 86,000 – 90,000 BOE/day, with crude oil and natural gas liquids production expected to average between 40,000 – 43,000 bbls/day. Following a limited completions program in North Dakota in the fourth quarter of 2016, capital spending is forecast to begin to ramp-up in the first half of 2017, driving strong liquids production growth in the back half of the year. Total fourth quarter production is expected to average 92,000 – 97,000 BOE/day, with a fourth quarter liquids production target of 45,000 - 50,000 bbls/day.

To support our 2017 capital program, we have increased our 2017 crude oil hedging program to 63% of our forecast crude oil production volumes, after royalties, and 23% of our natural gas production, after royalties. We have also added crude oil hedges in 2018 and 2019 on approximately 44% and 14%, respectively, based on our forecasted 2017 net crude oil production.

Operating expenses are expected to average approximately $7.85/BOE in 2017, modestly higher than 2016 levels as we expect to increase our corporate weighting of liquids production in 2017.

We expect cash G&A expenses in 2017 to average approximately $1.80/BOE. Although we expect total costs to decrease year over year, our per BOE expenses will remain flat due to lower production volumes.

Transportation costs are expected to average $3.90/BOE in 2017, an increase from 2016 levels. The increase is largely attributable to additional firm transportation commitments in the Marcellus that came into effect in August 2016 that deliver to higher priced markets, along with lower production volumes due to the non-operated year-end 2016 divestment and a weaker Canadian dollar projected in 2017 compared to 2016.

RESULTS OF OPERATIONS

Production

Average Daily Production Volumes	2016	2015	2014
Crude oil (bbls/day)	38,353	41,639	40,208
Natural gas liquids (bbls/day)	4,903	4,763	3,565
Natural gas (Mcf/day)	299,214	360,733	356,142
Total daily sales (BOE/day)	93,125	106,524	103,130

Production in 2016 averaged 93,125 BOE/day, in line with our guidance of 93,000 BOE/day. Crude oil and liquids volumes were 43,256 bbls/day, within our guidance range of 43,000 – 44,000 bbls/day. The 13% decrease in average production compared to the prior year was primarily due to the sale of non-core properties during the fourth quarter of 2015 and throughout the first three quarters of 2016 with associated production of approximately 11,800 BOE/day, and our reduced capital spending program compared to the prior year.

Our U.S. production decreased a modest 2% compared to 2015 despite our reduced capital spending. The decrease was primarily due to a 1,200 BOE/day or 4% reduction in Marcellus natural gas production due to lower investment and price related production curtailments during the year. In North Dakota, strong production from our crude oil properties offset the impact of decline and the fourth quarter 2015 sale of a portion of our non-operated properties.

Canadian production volumes decreased 12,310 BOE/day or 31% compared to the prior year, largely due to asset divestments. Price related shut-ins and asset declines also impacted Canadian production, but were offset somewhat by our November, 2016 acquisition of a Canadian waterflood property.

Our crude oil and natural gas liquids production accounted for 46% of our total average daily production in 2016, compared to 44% in 2015.

In 2015, production increased 3% over 2014 to average 106,524 BOE/day. Crude oil production increased 4% from the prior year due to 6,000 BOE/day or 28% growth in our North Dakota crude oil volumes. Our natural gas production was relatively consistent with 2014 at 360,733 Mcf/day, with 8% growth in our Marcellus production offset by decline in Canadian natural gas volumes over the same period.

2017 Guidance

We expect annual average production for 2017 of 86,000 – 90,000 BOE/day, including 40,000 – 43,000 bbls/day of crude oil and natural gas liquids. As a result of our increased capital spending program of $450 million, we expect strong production growth in the second half of the year, with liquids production expected to grow 25% from the beginning of 2017 to the end of the year. Accordingly, we are providing fourth quarter total average production guidance of 92,000 – 97,000 BOE/day and fourth quarter liquids production guidance of 45,000 – 50,000 bbls/day. This guidance includes the full year impact of our 2016 acquisitions and divestments, including the December 30, 2016 sale of 5,000 BOE/day non-operated North Dakota properties and the November 15, 2016 acquisition of a Canadian waterflood property.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, adjusted funds flow and financial condition. The following table summarizes our average selling prices, benchmark prices and differentials:

Pricing (average for the period)	2016	2015	2014
Benchmarks			
WTI crude oil (US$/bbl)	$ 43.32	$ 48.80	$ 93.00
AECO natural gas – monthly index ($/Mcf)	2.09	2.77	4.42
AECO natural gas – daily index ($/Mcf)	2.16	2.69	4.51
NYMEX natural gas – last day (US$/Mcf)	2.46	2.66	4.41
US/CDN average exchange rate	1.32	1.28	1.10
US/CDN period end exchange rate	1.34	1.38	1.16
Enerplus selling price(1)			
Crude oil ($/bbl)	$ 44.84	$ 48.43	$ 86.28
Natural gas liquids ($/bbl)	15.29	18.06	51.72
Natural gas ($/Mcf)	2.06	2.15	3.94
Average differentials			
MSW Edmonton – WTI (US$/bbl)	$ (3.21)	$ (3.93)	$ (7.17)
WCS Hardisty – WTI (US$/bbl)	(13.84)	(13.52)	(19.40)
Transco Leidy monthly – NYMEX (US$/Mcf)	(1.15)	(1.52)	(1.95)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(1.21)	(1.58)	(2.04)
AECO monthly – NYMEX (US$/Mcf)	(0.89)	(0.50)	(0.41)
Enerplus realized differentials(1)			
Canada crude oil – WTI (US$/bbl)	$ (13.21)	$ (13.34)	$ (17.36)
Canada natural gas – NYMEX (US$/Mcf)	(0.80)	(0.44)	(0.34)
Bakken crude oil – WTI (US$/bbl)	(7.46)	(9.44)	(12.94)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.93)	(1.37)	(1.43)

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

CRUDE OIL AND NATURAL GAS LIQUIDS

Our realized crude oil price in 2016 averaged $44.84/bbl, a 7% decrease compared to 2015. Benchmark WTI crude oil prices fell by 11% versus 2015 due to the continued oversupply of crude oil in the global markets for most of the year. In the fourth quarter of 2016, the Organization of the Petroleum Exporting Countries ("OPEC") and certain non-OPEC nations agreed to reduce production by approximately 1.8 million bbls/day through June 2017, which resulted in WTI prices strengthening at the end of the year to US$53.72/bbl.

Our Bakken sales price differential improved by 21% year over year, averaging US$7.46/bbl below WTI due to declining regional production and stronger local refinery demand. With the Dakota Access Pipeline expected to be completed and in service around mid-year 2017, increasing regional takeaway capacity, we are expecting our 2017 Bakken crude oil differential to improve to US$4.50/bbl below WTI, from our previous guidance of US$6.00/bbl below WTI. Canadian light sweet crude prices also improved, resulting in our Canadian realized price differentials to WTI narrowing slightly compared to the prior year.

We realized an average of $15.29/bbl on our natural gas liquids production, which was 15% lower than 2015 and largely in line with changes in underlying crude oil prices.

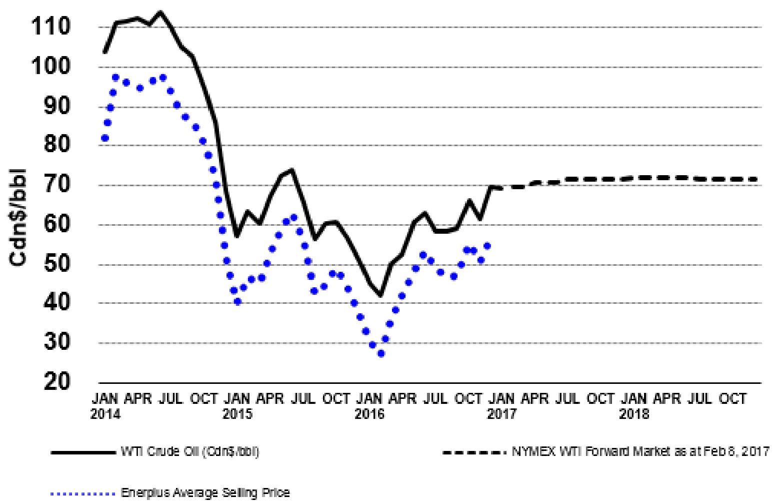
NATURAL GAS

Our realized natural gas price averaged $2.06/Mcf in 2016, a 4% decrease from 2015 realized prices but considerably stronger than the changes in benchmark prices during the period. NYMEX prices fell by 8% and AECO monthly prices fell by 25% compared to 2015 in response to excess inventories due to a warm winter in early 2016. However, with lower production levels and warmer than average summer temperatures in the U.S., NYMEX prices improved substantially over the course of the year and into 2017. In Alberta, concerns over congestion on regional pipelines due to continued production growth resulted in AECO prices averaging US$0.89/Mcf below NYMEX in 2016 compared to US$0.50/Mcf below NYMEX in 2015. Our overall realized natural gas price outperformed the benchmarks due to much stronger Marcellus basis differentials and the positive impact of our term AECO physical sales with fixed basis differentials at prices much narrower than where AECO basis market prices averaged.

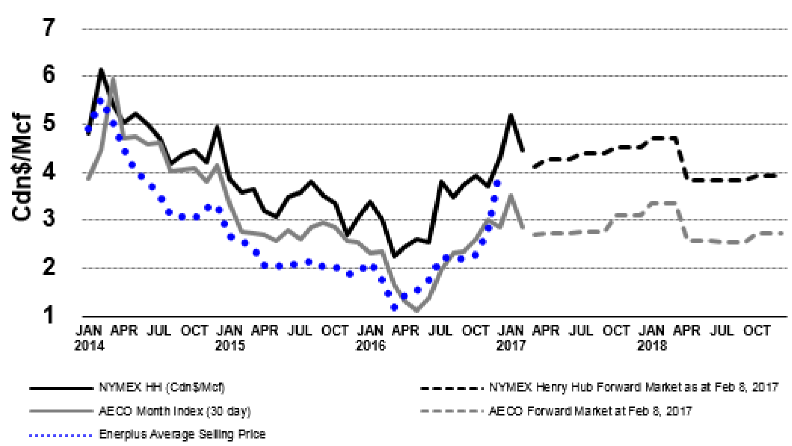
In the Marcellus, the Tennessee Gas Pipeline Zone 4 - 300 Leg and Transco Leidy monthly benchmark differentials averaged US$1.21/Mcf and US$1.15/Mcf below NYMEX compared to US$1.58/Mcf and US$1.52/Mcf below NYMEX in 2015. The strengthening in local Marcellus prices was due to additional pipeline capacity coming into service, as well as higher weather related demand in the region. Our realized sales price benefitted from August to December 2016 as we began to transport 30,000 Mcf/day of production to markets south of the Marcellus producing region, allowing us to realize sales prices closer to NYMEX pricing. This resulted in an average Marcellus realized sales price differential before transportation costs of US$0.93/Mcf below NYMEX, a 32% improvement from 2015.

We expect our realized Marcellus differentials in 2017 to continue to improve due to further pipeline capacity additions and stronger regional demand alleviating some of the constraints in the region. There is the potential for differentials to widen in certain periods of the year as seasonal demand falls and until sufficient pipeline capacity is built to fully relieve the congestion. We expect our Marcellus natural gas realized differential to average US$0.90/Mcf below NYMEX in 2017.

Monthly Crude Oil Prices



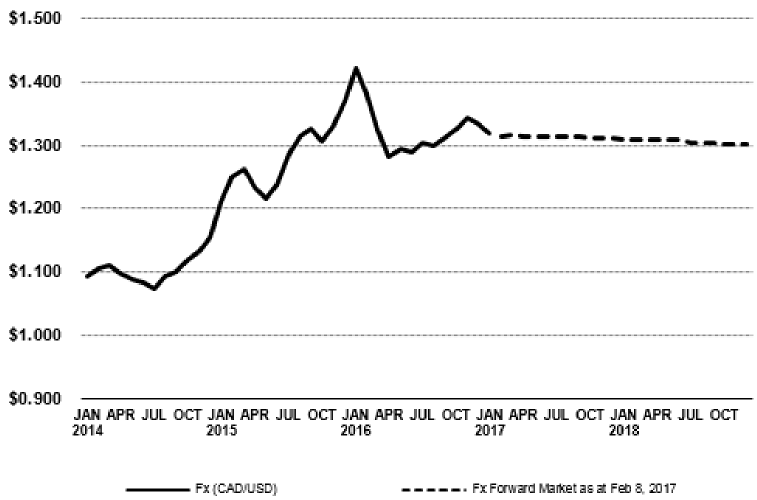
Monthly Natural Gas Prices



FOREIGN EXCHANGE

The Canadian dollar was volatile throughout 2016, beginning the year near a thirteen year low of 1.47 USD/CDN and strengthening to 1.25 USD/CDN in late April before closing the year at 1.34 USD/CDN. Overall, the Canadian dollar weakened relative to the U.S. dollar, averaging 1.32 USD/CDN. The majority of our oil and natural gas sales are based on U.S. dollar denominated indices, and a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. Because we report in Canadian dollars, the weaker Canadian dollar also increases our U.S. dollar denominated costs, capital spending and the cost of our U.S. dollar denominated senior notes.

Monthly USD/CDN Exchange Rate



Price Risk Management

We have a price risk management program that considers our overall financial position, the economics of our capital program and potential acquisitions.

As of February 23, 2017, we have hedged approximately 18,000 bbls/day of our crude oil production for 2017, which represents approximately 63% of our forecasted 2017 crude oil production, after royalties. For 2018, we have hedged 12,500 bbls/day, which represents approximately 44% of our forecasted 2017 crude oil production, after royalties. We have also added hedges through 2019 to protect the long term economics of a portion of our capital program. Our crude oil hedges are predominantly three way collars, which consist of a sold put, a purchased put and a sold call. When WTI prices settle below the sold put strike in any given month, the three way collars provide a limited amount of protection above the WTI index prices equal to the difference between the strike price of the purchased and sold puts. Overall, we continue to expect our crude oil hedge contracts to protect a significant portion of our adjusted funds flow.

As of February 23, 2017, we have hedged approximately 50,000 Mcf/day of our natural gas production for 2017 using NYMEX three way collars. This represents approximately 23% of our 2017 forecasted 2017 natural gas production, after royalties. When NYMEX prices settle below the sold put strike price in any given month, the three way collars provide a limited amount of protection above the NYMEX index prices equal to the value between the strike price of the purchased and sold puts.

The following is a summary of our financial contracts in place at February 23, 2017, expressed as a percentage of our anticipated production volumes, after royalties, for 2017:

	WTI Crude Oil (US$/bbl)[1]					NYMEX Natural Gas (US$/Mcf)[1]
	Jan 1, 2017 – Jun 30, 2017	Jul 1, 2017 – Dec 31, 2017	Jan 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Dec 31, 2019	Jan 1, 2017 – Dec 31, 2017
Swaps						
Sold Swaps	$ 53.50	$ 53.50	$ 53.73	$ 53.73	-	-
%	7%	7%	11%	11%	-	-
Three Way Collars						
Sold Puts	$ 38.94	$ 39.62	$ 43.13	$ 45.00	$ 43.75	$ 2.06
%	49%	63%	33%	3%	14%	23%
Purchased Puts	$ 50.29	$ 50.61	$ 54.00	$ 56.00	$ 54.69	$ 2.75
%	49%	63%	33%	3%	14%	23%
Sold Calls	$ 61.14	$ 60.33	$ 63.09	$ 70.00	$ 66.18	$ 3.41
%	49%	63%	33%	3%	14%	23%

(1) Based on weighted average price (before premiums) assuming average annual production of 88,000 BOE/day for 2017, less royalties and production taxes of 23%.

We did not have any foreign exchange contracts in place during 2016. In comparison, during 2015, we recorded realized foreign exchange losses of $39.2 million on foreign exchange costless collars and foreign exchange gains of $39.9 million and $3.3 million, respectively, on the unwind of our US$175 million foreign exchange swap and the final settlement of the foreign exchange swap on our US$54 million senior notes.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)

($ millions)	2016	2015	2014
Cash gains/(losses):			
Crude oil	$ 75.0	$ 217.2	$ 7.0
Natural gas	5.3	70.5	(3.5)
Total cash gains/(losses)	$ 80.3	$ 287.7	$ 3.5
Non-cash gains/(losses):			
Crude oil	$ (96.2)	$ (99.8)	$ 182.0
Natural gas	(13.5)	(45.2)	48.9
Total non-cash gains/(losses)	$ (109.7)	$ (145.0)	$ 230.9
Total gains/(losses)	$ (29.4)	$ 142.7	$ 234.4

(Per BOE)	2016	2015	2014
Total cash gains/(losses)	$ 2.36	$ 7.40	$ 0.09
Total non-cash gains/(losses)	(3.22)	(3.73)	6.14
Total gains/(losses)	$ (0.86)	$ 3.67	$ 6.23

During 2016, we realized cash gains of $75.0 million on our crude oil contracts and $5.3 million on our natural gas contracts. In comparison, in 2015 we realized cash gains of $217.2 million on our crude oil contracts and $70.5 million on our natural gas contracts. During 2014, we realized cash gains of $7.0 million on our crude oil contracts and cash losses of $3.5 million on our natural gas contracts. The cash gains in each year were due to contracts which provided floor protection above market prices, while cash losses were a result of natural gas 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. The fair value of our crude oil and natural gas contracts represented net loss positions of $28.8 million and $9.5 million, respectively, at December 31, 2016, and net gain positions of $67.4 million and $4.0 million, respectively, at December 31, 2015. The change in fair value of our crude oil and natural gas contracts represented losses of $96.2 million and $13.5 million, respectively, during 2016 and losses of $99.8 million and $45.2 million, respectively, during 2015.

Revenues

($ millions)	2016	2015	2014
Oil and natural gas sales	$ 882.1	$ 1,052.4	$ 1,849.3
Royalties	(159.4)	(168.0)	(323.1)
Oil and natural gas sales, net of royalties	$ 722.7	$ 884.4	$ 1,526.2

Oil and natural gas sales revenue for 2016 totaled $882.1 million, a decrease of 16% from $1,052.4 million in 2015. The decrease in revenue was a result of the continued decline in commodity prices compared to the prior year along with lower production due to non-core asset divestments and lower capital spending.

In 2015, oil and natural gas sales revenue decreased 43% to $1,052.4 million from $1,849.3 million in 2014 as a result of weak commodity prices, offset somewhat by growth in production volumes.

Royalties and Production Taxes

($ millions, except per BOE amounts)	2016	2015	2014
Royalties	$ 159.4	$ 168.0	$ 323.1
Per BOE	$ 4.67	$ 4.32	$ 8.58
Production taxes	$ 37.4	$ 50.9	$ 81.5
Per BOE	$ 1.10	$ 1.31	$ 2.17
Royalties and production taxes	$ 196.8	$ 218.9	$ 404.6
Per BOE	$ 5.77	$ 5.63	$ 10.75
Royalties and production taxes (% of oil and natural gas sales)	22%	21%	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. A large percentage of our production is from U.S. properties where royalty rates are generally not as sensitive to commodity price levels.

Royalties and production taxes were in line with our guidance for 2016, averaging 22% of oil and natural gas sales, before transportation. Royalties and production taxes decreased to $196.8 million in 2016 from $218.9 million in 2015 primarily due to lower production volumes, a decrease in realized crude oil and natural gas prices and a 1.5% rate reduction of production taxes in North Dakota. In 2015, royalties and production taxes decreased to $218.9 million from $404.6 million in the prior year primarily due to decreased realized crude oil and natural gas prices.

2017 Guidance

We expect royalty and production taxes in 2017 to average 23% of our oil and gas sales, before transportation. The increase compared to 2016 is due to the higher percentage of U.S. production as a result of additional capital spending and growth in our U.S. assets, as well as the divestment of our non-core Canadian properties during 2016.

Operating Expenses

($ millions, except per BOE amounts)	2016	2015	2014
Cash operating expenses	$ 249.0	$ 340.1	$ 347.3
Non-cash (gains)/losses(1)	(1.1)	0.4	1.3
Total operating expenses	$ 247.9	$ 340.5	$ 348.6
Per BOE	$ 7.27	$ 8.76	$ 9.26

(1) Non-cash (gains)/losses on fixed price electricity swaps.

Operating expenses during 2016 were $247.9 million or $7.27/BOE, beating our guidance of $7.50/BOE, largely due to higher than expected production volumes from our lower operating cost Marcellus properties during the fourth quarter. Compared to 2015, expenses decreased $92.6 million or 27% primarily due to successful cost saving initiatives, lower repairs and maintenance costs and the divestment of higher operating cost Canadian properties throughout 2016.

Operating expenses during 2015 were $340.5 million or $8.76/BOE compared to $348.6 million or $9.26/BOE in 2014. The improvement resulted mainly from cost savings and a continued increase in the U.S. weighting of production, which has lower operating metrics. This was offset in part by the impact of a weaker Canadian dollar on our U.S. dollar denominated operating expenses.

2017 Guidance

We expect operating expenses of $7.85/BOE in 2017. The modest increase from 2016 is a result of the expected increase in the corporate weighting of our liquids production.

Transportation Costs

($ millions, except per BOE amounts)	2016	2015	2014
Transportation costs	$ 107.1	$ 114.7	$ 101.2
Per BOE	$ 3.14	$ 2.95	$ 2.69

Transportation costs increased on a per BOE basis throughout the year to average $3.14/BOE in 2016, consistent with our guidance of $3.15/BOE and a 6% increase compared to $2.95/BOE in 2015. The increase was primarily due to the increased weighting of U.S. production with higher associated transportation costs and additional firm transportation commitments in the Marcellus, effective August 2016.

Transportation costs increased to $2.95/BOE in 2015 compared to $2.69/BOE in 2014 as a result of increasing U.S. production and costs associated with securing U.S. pipeline capacity. The impact of a weakening Canadian dollar on our U.S. transportation costs further increased our total reported expense.

2017 Guidance

We expect transportation costs of $3.90/BOE in 2017. The increase from 2016 is largely attributable to additional firm transportation commitments in the Marcellus that came into effect in August 2016 to deliver production to higher priced markets, lower production volumes due to the year-end 2016 divestment of non-operated North Dakota properties and a weaker Canadian dollar projected in 2017.

Netbacks

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

Netbacks by Property Type	Year ended December 31, 2016 Crude Oil		Natural Gas		Total
Average Daily Production	47,206 BOE/day		275,538 Mcfe/day		93,125 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)		(per Mcfe)		(per BOE)
Oil and natural gas sales	$ 37.86		$ 2.26		$ 25.88
Royalties and production taxes	(9.38)		(0.34)		(5.77)
Cash operating expenses	(10.29)		(0.72)		(7.31)
Transportation costs	(1.97)		(0.72)		(3.14)
Netback before hedging	$ 16.22		$ 0.48		$ 9.66
Cash gains/(losses)	4.34		0.05		2.36
Netback after hedging	$ 20.56		$ 0.53		$ 12.02
Netback before hedging ($ millions)	$ 280.4		$ 48.8		$ 329.2
Netback after hedging ($ millions)	$ 355.3		$ 54.2		$ 409.5

Netbacks by Property Type	Year ended December 31, 2015 Crude Oil	Natural Gas	Total
Average Daily Production	49,069 BOE/day	344,730 Mcfe/day	106,524 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 43.67	$ 2.15	$ 27.07
Royalties and production taxes	(10.54)	(0.24)	(5.63)
Cash operating expenses	(11.98)	(1.00)	(8.75)
Transportation costs	(1.84)	(0.65)	(2.95)
Netback before hedging	$ 19.31	$ 0.26	$ 9.74
Cash gains/(losses)	12.13	0.56	7.40
Netback after hedging	$ 31.44	$ 0.82	$ 17.14
Netback before hedging ($ millions)	$ 345.7	$ 33.0	$ 378.7
Netback after hedging ($ millions)	$ 562.9	$ 103.5	$ 666.4

Netbacks by Property Type	Year ended December 31, 2014 Crude Oil	Natural Gas	Total
Average Daily Production	45,225 BOE/day	347,430 Mcfe/day	103,130 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 79.12	$ 4.28	$ 49.13
Royalties and production taxes	(19.78)	(0.61)	(10.75)
Cash operating expenses	(11.76)	(1.21)	(9.23)
Transportation costs	(1.89)	(0.55)	(2.69)
Netback before hedging	$ 45.69	$ 1.91	$ 26.46
Cash gains/(losses)	0.42	(0.03)	0.09
Netback after hedging	$ 46.11	$ 1.88	$ 26.55
Netback before hedging ($ millions)	$ 754.3	$ 241.9	$ 996.2
Netback after hedging ($ millions)	$ 761.3	$ 238.4	$ 999.7

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

Crude oil and natural gas netbacks per BOE after hedging were lower during 2016 compared to 2015 and 2014 primarily due to the weakness in commodity prices compared to both the prior years and lower realized hedging gains compared to 2015, partially offset by significant improvements in our operating costs. During 2016, our crude oil properties accounted for 85% and 87% of our netback before and after hedging, respectively.

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 to the Financial Statements for further details.

($ millions)	2016	2015	2014
Cash:			
G&A expense	$ 59.8	$ 81.3	$ 83.5
Share-based compensation expense	3.1	0.9	(1.2)
Non-Cash:			
Share-based compensation expense	27.0	19.6	13.4
Equity swap loss/(gain)	(3.6)	2.1	9.3
Total G&A expenses	$ 86.3	$ 103.9	$ 105.0

(Per BOE)	2016	2015	2014
Cash:			
G&A expense	$ 1.75	$ 2.09	$ 2.22
Share-based compensation expense	0.09	0.02	(0.03)
Non-Cash:			
Share-based compensation expense	0.80	0.51	0.36
Equity swap loss/(gain)	(0.11)	0.05	0.24
Total G&A expenses	$ 2.53	$ 2.67	$ 2.79

Cash G&A expenses in 2016 totaled $59.8 million ($1.75/BOE), outperforming our guidance of $1.80/BOE and a decrease of 26% from $81.3 million ($2.09/BOE) in 2015. The reduction from 2015 was primarily due to continued cost savings initiatives and the impact of ongoing staff reductions as we continue to divest of non-core assets and focus our business.

Our share price increased significantly during 2016, resulting in cash SBC expense of $3.1 million ($0.09/BOE) compared to an expense of $0.9 million ($0.02/BOE) in 2015. Following the settlement of the final grants of our cash-settled Restricted Share Unit ("RSU") plans during the year, the Director Share Unit ("DSU") plan is our only remaining LTI plan that we intend to settle in cash. We recorded non-cash SBC of $27.0 million ($0.80/BOE) in 2016 compared to $19.6 million ($0.51/BOE) in 2015. The increase in non-cash SBC was a result of an improvement in our performance multiplier based on our relative return in the Toronto Stock Exchange Oil and Gas Producers Index, along with additional grants issued under the treasury-settled LTI plans rather than the cash-settled plans.

Cash G&A expenses in 2015 were $81.3 million ($2.09/BOE) compared to $83.5 million ($2.22/BOE) in 2014. The decrease in cash G&A expenses compared to 2014 was primarily due to a 20% reduction in staff levels offset by one-time severance charges. Cash SBC expense was $0.9 million ($0.02/BOE) in 2015 compared to a recovery of $1.2 million ($0.03/BOE) in 2014. We recorded non-cash SBC of $19.6 million ($0.51/BOE) in 2015 compared to $13.4 million ($0.36/BOE) in 2014. The increase in non-cash SBC was a result of additional grants issued under the treasury-settled LTI plans.

We have hedged a portion of the outstanding cash-settled units under our LTI plans. We recorded a non-cash mark-to-market gain of $3.6 million on these hedges in 2016 (2015 - $2.1 million loss; 2014 – $9.3 million loss). As of December 31, 2016, we have 470,000 units hedged at a weighted average price of $16.89/share.

2017 Guidance

We expect our cash G&A expense to be approximately $1.80/BOE in 2017, consistent with 2016 despite lower expected production levels.

Interest Expense

($ millions)	2016	2015	2014
Interest on senior notes and bank facility	$ 45.4	$ 66.5	$ 62.2
Non-cash interest expense	-	-	0.6
Total interest expense	$ 45.4	$ 66.5	$ 62.8

Interest on our senior notes and bank credit facility in 2016 decreased 32% to $45.4 million compared to $66.5 million in 2015. The decrease in interest expense corresponds to a decrease in the aggregate principal amount of our outstanding senior notes following our repurchase of US$267 million of senior notes during the first half of 2016. The repurchase was funded by asset divestment proceeds and lower interest rate bank debt, which was repaid following our May 31, 2016 equity financing and the closing of our second quarter Canadian non-core asset divestment.

Interest expense increased to $66.5 million in 2015 from $62.8 million in 2014 due to the impact of a weaker Canadian dollar on our U.S. dollar denominated interest payments and an increased weighting of senior notes with higher interest rates compared to our bank credit facility following our US$200 million private placement in September 2014. Non-cash amounts recorded in 2014 consisted of unrealized losses on the interest component of our cross currency interest rate swap. See Note 11 to the Financial Statements for further details.

At December 31, 2016, approximately 97% of our debt consisted of fixed interest rate senior notes and approximately 3% was floating bank debt with weighted average interest rates of 5.0% and 2.6%, respectively.

Foreign Exchange

($ millions)	2016	2015	2014
Realized loss/(gain)	$ 0.1	$ (8.7)	$ 11.2
Unrealized loss/(gain)	(40.6)	182.6	45.9
Total foreign exchange loss/(gain)	$ (40.5)	$ 173.9	$ 57.1
US/CDN average exchange rate	1.32	1.28	1.10
US/CDN period end exchange rate	1.34	1.38	1.16

We recorded a net foreign exchange gain of $40.5 million in 2016 compared to losses of $173.9 million and $57.1 million in 2015 and 2014, respectively. Our foreign exchange exposure relates to fluctuations in the Canadian and U.S. dollar exchange rate.

In 2016, we recorded a realized loss of $0.1 million on day-to-day transactions denominated in foreign currencies, compared to a gain of $8.7 million and a loss of $11.2 million in 2015 and 2014, respectively. In 2015, realized foreign exchange included a gain of $39.9 million on the unwind of our US$175 million foreign exchange swaps and a gain of $3.3 million on the final settlement of our US$54 million senior notes and the corresponding foreign exchange swap. These gains were offset by cumulative losses of $39.2 million on our foreign exchange collars with final settlements in December 2015. In 2014, we recorded a $15.8 million loss on the final settlement of our cross currency interest rate swap and a gain of $0.7 million on our costless collars.

Unrealized foreign exchange gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. Comparing December 31, 2016 to December 31, 2015, the Canadian dollar strengthened relative to the U.S. dollar and we reduced our U.S. dollar denominated senior notes by 33%, resulting in an unrealized gain of $40.6 million. See Note 12 to the Financial Statements for further details.

Capital Investment

($ millions)	2016	2015	2014
Capital spending	$ 209.1	$ 493.4	$ 811.0
Office capital	1.5	4.5	7.0
Sub-total	210.6	497.9	818.0
Property and land acquisitions	$ 126.1	$ 9.5	$ 18.5
Property divestments	(670.4)	(286.6)	(203.6)
Sub-total	(544.3)	(277.1)	(185.1)
Total	$ (333.7)	$ 220.8	$ 632.9

2016

Capital spending in 2016 totaled $209.1 million, slightly below our revised guidance of $215 million due to some weather related deferrals of spending during the fourth quarter. We continued to focus capital on our core areas during 2016, spending $136.4 million on our North Dakota crude oil properties, $44.4 million on our Canadian crude oil waterflood properties and $24.3 million on our Marcellus natural gas assets. Through our capital program in 2016 we added 43 MMBOE of gross proved plus probable reserves, replacing 126% of our 2016 production, before accounting for acquisitions and divestments.

We recorded net divestment proceeds of $670.4 million in 2016. In Canada, we sold properties for combined proceeds of $281.0 million with production of approximately 8,500 BOE/day. Sold properties consisted mainly of natural gas assets, and included certain Deep Basin natural gas properties with production of 5,400 BOE/day and non-core properties in northwest Alberta with production of 2,300 BOE/day. Divestments resulted in a $35.6 million reduction to future asset retirement obligations. On December 30, 2016, we closed the sale of our non-operated assets in North Dakota with production of approximately 5,000 BOE/day for proceeds of $392.0 million, which was reported as restricted cash at December 31, 2016.

Property and land acquisitions in 2016 totaled $126.1 million, largely due to our acquisition of a Canadian waterflood property for a purchase price of $110.3 million, net of closing adjustments.

2015

Capital spending in 2015 totaled $493.4 million and included spending of $302.3 million on our North Dakota crude oil properties, $115.7 million on our Canadian crude oil properties, $32.2 million on our Marcellus assets and $40.4 million on our Deep Basin properties in Canada. Through our capital program in 2015 we added 42 MMBOE of gross proved plus probable reserves, replacing 108% of our 2015 production, before accounting for acquisitions and divestments.

During 2015, we recorded net divestment proceeds of $286.6 million. In Canada, we divested of assets for combined proceeds of $198.9 million with production of approximately 4,900 BOE/day including the sale of our Pembina waterflood assets and certain non-core shallow gas assets with production of 2,700 BOE/day. In the U.S., we divested of assets for combined proceeds of $87.7 million with production of approximately 1,250 BOE/day, including the sale of a portion of our non-operated North Dakota properties for proceeds of $80.4 million, and our operated Marcellus assets for proceeds of $3.5 million.

Property and land acquisitions in 2015 totaled $9.5 million and included minor acquisitions of leases and undeveloped land.

2014

Capital spending in 2014 totaled $811.0 million and included spending of $343.7 million on our North Dakota crude oil properties, $176.6 million on our Canadian crude oil properties, $158.8 million on our Marcellus assets and $124.5 million on our deep gas properties in Canada. Through our capital program in 2014 we added 75 MMBOE of gross proved plus probable reserves, replacing over 200% of our 2014 production.

Property divestments in 2014 totaled $203.6 million. In Canada we divested of natural gas properties in the Deep Basin area with production of approximately 3,100 BOE/day for proceeds of $91.0 million and recognized the remaining $65.8 million of proceeds on the 2013 sale of our undeveloped Montney acreage. During the first quarter, we sold our gross overriding royalty interest in the Jonah natural gas property in Wyoming with production of approximately 400 BOE/day for proceeds of $44.0 million, after closing adjustments. Property and land acquisitions in 2014 totaled $18.5 million and included several minor acquisitions across our core areas.

2017 Guidance

To re-position ourselves for growth in 2017, we are increasing our capital spending guidance to $450 million, more than twice our spending levels in 2016. We will continue to focus our spending on our core areas, with $330 million currently allocated to North Dakota crude oil properties, $60 million to Canadian waterflood crude oil properties and $60 million to the Marcellus natural gas properties.

Gain on Asset Sales and Note Repurchases

We recorded gains of $559.2 million on asset divestments during 2016, including a gain of $339.4 million on the fourth quarter sale of our non-operated North Dakota property. No gains were recorded on asset sales in 2015 or 2014. Under full cost accounting rules, divestments of oil and natural gas properties are generally accounted for as adjustments to the full cost pool with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would significantly alter the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized. Gains and losses are evaluated on a case by case basis for each asset sale, and future sales may or may not result in such treatment.

During the first half of 2016, we recorded a total gain of $19.3 million on the repurchase of US$267 million of outstanding senior notes at prices between 90% of par and par value.

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

($ millions, except per BOE amounts)	2016	2015	2014
DD&A expense	$ 329.0	$ 508.2	$ 567.7
Per BOE	$ 9.65	$ 13.06	$ 15.08

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. DD&A has decreased from 2014 to 2016 primarily due to the quarterly asset impairments recorded during 2015 and 2016 under the U.S. GAAP full cost ceiling test methodology.

Impairments

PP&E

($ millions)	2016	2015	2014
Canada cost centre	$ 89.4	$ 286.7	$ —
U.S. cost centre	211.8	1,065.7	—
Total Impairments	$ 301.2	$ 1,352.4	$ —

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country cost centre 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. Standardized Measure is not related to our capital spending investment criteria and is not a fair value based measurement, but rather a prescribed accounting calculation. Under U.S. GAAP impairments are not reversed in future periods.

The trailing twelve month average crude oil and natural gas prices have decreased significantly in 2016 and 2015, resulting in non-cash impairments totaling $301.2 million and $1,352.4 million (before tax), respectively. We did not record any impairments on our oil and natural gas properties in 2014.

The following table outlines the twelve month average trailing benchmark prices and exchange rates used in our ceiling test at December 31, 2016, 2015 and 2014:

Year	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
2016	$ 42.75	1.32	$ 52.26	$ 2.49	$ 2.17
2015	$ 50.28	1.27	$ 59.38	$ 2.58	$ 2.69
2014	$ 94.99	1.09	$ 94.84	$ 4.30	$ 4.60

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. For the next year, the primary factors include future first-day-of-the-month commodity prices, reserves revisions, our capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. Although the twelve month average trailing commodity prices are below current levels, there is the potential for prices to decline further, impacting the ceiling value which could result in further non-cash impairments.

Goodwill

Goodwill impairment testing is performed annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. We perform a qualitative assessment of goodwill by evaluating potential indicators of impairment, and if it is more likely than not that the fair value of the reporting unit is less than its carrying value we perform quantitative impairment tests. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to earnings in the consolidated statements of income/(loss) in the Financial Statements.

Our annual goodwill impairment assessments as at December 31, 2016 and 2015 indicated no impairment.

Asset Retirement Obligation

In connection with our operations, we incur abandonment and reclamation costs related to assets, such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are based on management's estimate of our net ownership interest, 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 $181.7 million at December 31, 2016, compared to $206.4 million at December 31, 2015. The decrease was largely due to the removal of $35.6 million of asset retirement obligations related to asset divestments during 2016. See Note 8 to the Financial Statements for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2016, we spent $8.4 million (2015 – $14.9 million) on our asset retirement obligations and we expect to spend approximately $13.1 million in 2017. The majority of our abandonment and reclamation costs are expected to be incurred between 2025 and 2055. We do not reserve cash or assets for the purpose of funding our future asset retirement obligations. Any abandonment and reclamation costs are anticipated to be funded out of cash flow and available credit facilities.

Income Taxes

($ millions)	2016	2015	2014
Current tax expense/(recovery)	$ (2.4)	$ (16.9)	$ 5.0
Deferred tax expense/(recovery)	(234.8)	(150.6)	132.8
Total tax expense/(recovery)	$ (237.2)	$ (167.5)	$ 137.8

Our current tax recovery mainly relates to a refund of U.S. Alternative Minimum Tax ("AMT") from a prior period.

The total tax recovery in 2016 was $237.2 million, compared to $167.5 million in 2015. The increased recovery in 2016 is due primarily to the removal of a portion of our valuation allowance recorded in 2015 due to higher future taxable income projected this year compared to 2015. We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not all or a portion of our deferred income tax assets will be realized. We have considered available positive and negative evidence, including future taxable income and reversing existing temporary differences in making this assessment. This assessment is primarily the result of projecting future taxable income using December 30 benchmark forward prices for 2017, held constant and adjusted for other significant items affecting taxable income. Had we utilized forecast prices and costs to estimate future taxable income we expect that all of our deferred income tax assets would be realized and no valuation allowance would be required. Our overall deferred income tax asset, net of valuation allowance, is $733.4 million as at December 31, 2016 (2015 - $516.1 million).

In 2015, our total tax recovery was $167.5 million compared to an expense of $137.8 million in 2014. The recovery in 2015 was due primarily to lower income, which was impacted by a $1,352.4 million non-cash charge for asset impairments and a valuation allowance recorded against a portion of our deferred income tax asset.

Our estimated tax pools at December 31, 2016 are as follows:

Pool Type ($ millions)		**2016**
Canada		
Canadian development expenditures ("CDE")	$	63
Canadian exploration expenditures ("CEE")		236
Undepreciated capital costs ("UCC")		166
Non-capital losses and other credits		397
	$	862
U.S.		
Alternative minimum tax credit ("AMT")	$	112
Net operating losses		894
Depletable and depreciable assets		1,370
	$	2,376
Total tax pools and credits	$	3,238
Capital losses	$	1,224

Capital losses reflect the balance of unused capital losses available for carry-forward in Canada. These capital losses have an indefinite carry-forward period however can only be used to offset capital gains. We do not anticipate future capital gains that will allow us to utilize the capital losses. Therefore, a full valuation allowance has been applied to the deferred tax asset in respect of these capital losses.

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 maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At December 31, 2016, our senior debt to adjusted EBITDA ratio was 0.8x and our net debt to adjusted funds flow ratio was 1.2x, a significant improvement from 2.2x and 2.5x, respectively, at December 31, 2015. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate our liquidity.

We strengthened our financial position significantly in 2016, reducing our net debt by 69% over the twelve month period. The overall reduction in debt was funded through proceeds from our May 2016 equity issuance and our ongoing non-core asset divestment program. On May 31, 2016, we completed an equity financing for 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million, net of issue costs). Asset divestments throughout 2016 resulted in aggregate divestment proceeds of $670.4 million. This additional liquidity was used to repay our bank credit facility, repurchase US$267 million of senior notes during the first half of 2016, at prices ranging from 90% of par to par value, and purchase our Canadian waterflood property in November for $110.3 million.

Net acquisition and divestment proceeds include $392.0 million from the sale of non-operated North Dakota properties, which were classified as restricted cash on the December 31, 2016 balance sheet. As of the date of this report, we expect to continue to hold these funds in escrow for a period of up to 180 days from the date of closing to facilitate possible future like-kind transactions in accordance with U.S. federal tax regulations.

Total debt, net of cash and restricted cash, at December 31, 2016 was $375.5 million compared to $1,216.2 million at December 31, 2015. Total debt was comprised of $23.2 million of bank indebtedness and $745.6 million of senior notes less $393.3 million in cash, including restricted cash. Our next scheduled senior notes repayment of US$22 million is due in June 2017 with remaining maturities extending to 2026.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by adjusted funds flow, was 80% for 2016 compared to 128% in 2015. After adjusting for net acquisition and divestment proceeds, our funding surplus for the year ended December 31, 2016 was $603.8 million compared to $144.8 million in 2015. We expect to continue to pay monthly dividends to our shareholders of $0.01 per share, however, if economic conditions change we may make adjustments.

Our working capital deficiency, excluding cash and current deferred financial and tax balances, decreased to $94.4 million at December 31, 2016 from $104.0 million at December 31, 2015. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, adjusted funds flow and our bank credit facility. In addition, we have sufficient liquidity to meet our financial commitments for the near term, as disclosed under "Commitments" below.

During the fourth quarter, we completed a one year extension of our $800 million senior, unsecured, covenant-based bank credit facility, which now matures on October 31, 2019. There were no other amendments to the agreement terms or debt covenants. Drawn fees on our bank credit facility 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 December 31, 2016 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 December 31, 2016:

Covenant Description		December 31, 2016
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA	3.5x	0.8x
Total debt to adjusted EBITDA	4.0x	0.8x
Total debt to capitalization	50%	23%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA(1)	3.0x – 3.5x	0.8x
Senior debt to consolidated present value of total proved reserves(2)	60%	28%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	20.4x

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 December 31, 2016 were $451.8 million and $921.0 million, respectively.
"Total Debt" is calculated as the sum of Senior Debt plus subordinated debt. Enerplus currently does not have any subordinated debt.
"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes
(1) Senior Debt to adjusted EBITDA maximum ratio for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.
(2) Maximum debt to consolidated present value of total proved reserves is calculated annually on December 31 based on before tax reserves at forecast prices discounted at 10%.

Counterparty Credit

OIL AND NATURAL GAS SALES COUNTERPARTIES

Our oil and natural gas receivables are with customers in the oil and gas industry and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. A credit review process is in place to assess and monitor our counterparties' creditworthiness on a regular basis. This process involves reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted, we obtain financial assurances such as letters of credit, parental guarantees or third party insurance to mitigate a portion of our credit risk. This process is utilized for both our oil and natural gas sales counterparties as well as our financial derivative counterparties.

FINANCIAL DERIVATIVE COUNTERPARTIES

We are exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. We mitigate this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the great majority of our financial counterparties. These agreements provide some credit protection by generally allowing parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. To date we have not experienced any losses due to non-performance by our derivative counterparties. At December 31, 2016, we had $40.9 million of mark-to-market liabilities. The majority of our outstanding derivative contracts are with financial institutions which are members of our bank syndicate. All of our derivative counterparties are considered investment grade.

Dividends

($ millions, except per share amounts)	2016	2015	2014
Cash dividends	$ 35.4	$ 132.0	$ 199.3
Stock dividend plan	—	—	21.8
Total dividends to shareholders	$ 35.4	$ 132.0	$ 221.1
Per weighted average share (Basic)	$ 0.16	$ 0.64	$ 1.08

We reported total dividends of $35.4 million or $0.16 per share to our shareholders in 2016. During 2015 and 2014 we reported total dividends of $132.0 million or $0.64 per share and $221.1 million or $1.08 per share, respectively.

Cash dividends for 2016 represented approximately 12% of adjusted funds flow, compared to approximately 27% in 2015 and 23% in 2014. 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.

To provide additional financial flexibility and to better balance adjusted funds flow with capital and dividends, we reduced our monthly dividend to $0.01 per share, effective with our April 2016 payment. During 2015, we reduced our monthly dividend twice, from $0.09 per share to $0.05 per share in April and to $0.03 per share in December.

The dividend is part of our strategy to create shareholder value; however, a sustained low price environment may impact our ability to pay dividends. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	2016	2015	2014
Share capital ($ millions)	$ 3,366.0	$ 3,133.5	$ 3,120.0
Common shares outstanding (thousands)	240,483	206,539	205,732
Weighted average shares outstanding – basic (thousands)	226,530	206,205	204,510
Weighted average shares outstanding – diluted (thousands)	231,293	206,205	207,424

On May 31, 2016, 33,350,000 common shares were issued at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million, net of issue costs).

During 2016, a total of 594,000 shares (2015 – 807,000; 2014 – 2,974,000) and $9.4 million of additional equity (2015 – $13.3 million; 2014 – $53.2 million) was issued pursuant to the treasury-settled LTI plans. For further details see Note 14 to the Financial Statements.

At February 23, 2017, we had 241,010,880 shares outstanding.

Commitments

As at December 31, 2016 we had the following minimum annual commitments:

		Minimum Annual Commitment Each Year					Total Committed
($ millions)	Total	2017	2018	2019	2020	2021	after 2021
Bank credit facility(1)	$ 23.2	$ —	$ —	$ 23.2	$ —	$ —	$ —
Senior notes(1)	746	30	29.5	59.5	109.6	109.6	407.9
Transportation commitments	293.6	31.9	29.1	24.6	22.8	19.5	165.7
Processing commitments	42.9	11.4	10.1	10.1	1.6	1.6	8.1
Drilling and completions	29.1	29.1	—	—	—	—	—
Office lease commitments	88.3	12.2	12.0	10.5	10.8	10.8	32.0
Sublease recoveries	(9.3)	(2.0)	(1.6)	(1.7)	(1.8)	(1.5)	(0.7)
Net office lease commitments	79.1	10.2	10.4	8.8	9.1	9.3	31.2
Total commitments(2)(3)	$ 1,213.6	$ 112.2	$ 79.2	$ 126.3	$ 143.0	$ 140.0	$ 612.9

(1) Interest payments have not been included.
(2) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(3) US$ commitments have been converted to CDN$ using the December 31, 2016 foreign exchange rate of 1.3427.

In the Marcellus, we have firm sales contracts for up to 65,000 Mcf/day through 2026. We also have firm transportation agreements in place for approximately 66,000 Mcf/day, which expire between 2020 and 2033. This includes the agreement for additional interstate pipeline capacity on the Tennessee Gas Pipeline from our Marcellus producing region to downstream connections that became effective in August 2016. Under this agreement, we are committed to a US$0.63/Mcf demand toll for 30,000 Mcf/day of natural gas for 11 years, reducing to 15,000 Mcf/day for an additional 9 years, with a total estimated transportation commitment of $148.3 million extending to 2036. We have also entered into a binding contract for five years of firm transportation capacity for 30,000 Mcf/day on the PennEast pipeline project. This project is currently pending regulatory approval with an expected in-service date of 2018.

In Canada, we have various firm transportation agreements for approximately 2,700 BOE/day of our crude oil and natural gas liquids production in 2017, decreasing to approximately 1,800 BOE/day on average from 2018 to 2027. We also have firm natural gas transportation contracts in 2017 for approximately 99,000 Mcf/day. At December 31, 2016, we have firm natural gas liquids fractionation contracts for 825 BOE/day, which increase to 1,125 BOE/day from April 2017 through 2026.

Our Canadian office lease is committed to 2024 and our U.S. office lease expires in 2019. Annual costs of these lease commitments include rent and operating fees. Our office lease commitments are shown net of sublease agreements, which we entered into to reduce our obligations.

Our commitments, contingencies and guarantees are more fully described in Note 16 to the Financial Statements.

SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

	Year ended December 31, 2016			Year ended December 31, 2015		
(millions, except per unit amounts)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Average Daily Production Volumes[(1)]						
Crude oil (bbls/day)	13,089	25,264	38,353	15,165	26,474	41,639
Natural gas liquids (bbls/day)	1,408	3,495	4,903	1,997	2,766	4,763
Natural gas (Mcf/day)	79,057	220,157	299,214	136,924	223,809	360,733
Total average daily production (BOE/day)	27,673	65,452	93,125	39,983	66,541	106,524
Pricing[(2)]						
Crude oil (per bbl)	$ 39.91	$ 47.39	$ 44.84	$ 45.28	$ 50.23	$ 48.43
Natural gas liquids (per bbl)	27.52	10.36	15.29	29.41	9.88	18.06
Natural gas (per Mcf)	2.20	2.00	2.06	2.83	1.74	2.15
Capital Expenditures						
Capital spending	$ 44.4	$ 164.7	$ 209.1	$ 157.7	$ 335.7	$ 493.4
Acquisitions	114.4	11.7	126.1	3.6	5.9	9.5
Divestments	(281.0)	(389.4)	(670.4)	(198.9)	(87.7)	(286.6)
Netback[(3)] Before Hedging						
Oil and natural gas sales	$ 269.2	$ 612.9	$ 882.1	$ 414.4	$ 638.0	$ 1052.4
Royalties	(35.8)	(123.6)	(159.4)	(44.8)	(123.2)	(168.0)
Production taxes	(2.5)	(34.9)	(37.4)	(5.5)	(45.4)	(50.9)
Cash operating expenses	(135.7)	(113.3)	(249.0)	(216.7)	(123.4)	(340.1)
Transportation costs	(14.0)	(93.1)	(107.1)	(22.6)	(92.1)	(114.7)
Netback before hedging	$ 81.2	$ 248.0	$ 329.2	$ 124.8	$ 253.9	$ 378.7
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 29.4	$ —	$ 29.4	$ (142.7)	$ —	$ (142.7)
General and administrative expense[(4)]	63.9	22.4	86.3	77.0	26.9	103.9
Current income tax expense/(recovery)	(0.7)	(1.7)	(2.4)	(0.8)	(16.1)	(16.9)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See “Non-GAAP Measures” section in this MD&A.
(4) Includes share-based compensation.

THREE YEAR SUMMARY OF KEY MEASURES

($ millions, except per share amounts)	2016	2015	2014
Oil and natural gas sales, net of royalties	$ 722.7	$ 884.4	$ 1,526.2
Net income/(loss)	397.4	(1,523.4)	299.1
Per share (Basic)	1.75	(7.39)	1.46
Per share (Diluted)	1.72	(7.39)	1.44
Adjusted funds flow(1)	305.6	493.1	859.0
Cash and stock dividends(2)	35.4	132.0	221.1
Per share (Basic)(2)	0.16	0.64	1.08
Total assets	2,638.9	2,581.2	4,031.5
Debt net of cash and restricted cash	375.5	1,216.2	1,134.9

(1) See “Non-GAAP Measures” section of this MD&A.
(2) Calculated based on dividends paid or payable. Cash and stock dividends to shareholders per share may not correspond to actual dividends as a result of using the annual weighted average shares outstanding.

2016 versus 2015

Net oil and natural gas sales were $722.7 million in 2016 compared to $884.4 million in 2015 due to weaker commodity prices and lower production volumes as a result of our asset divestments over the period.

We reported net income of $397.4 million in 2016 compared to a net loss of $1,523.4 million in 2015 primarily due to decreases of $1,051.3 million in non-cash asset impairment charges and $179.2 in DD&A recorded on our crude oil and natural gas assets and gains of $578.5 million realized in 2016 on our asset divestments and the prepayment of senior notes.

Adjusted funds flow decreased 38% to $305.6 million in 2016 from $493.1 million in 2015. The decrease was mainly a result of a $207.4 million decrease in realized gains on commodity hedges and a $161.7 million decline in net crude oil and gas sales over the period, offset by a combined decrease in cash operating costs, interest expense and cash G&A expenses of $133.7 million.

2015 versus 2014

In 2015, oil and natural gas sales, net income and adjusted funds flow decreased due to weak commodity prices, which were somewhat offset by production growth. A net loss was realized in 2015 primarily as a result of non-cash asset impairment charges of $1,352.4 million and a non-cash valuation allowance on our deferred income tax asset, along with lower oil and natural gas sales revenue and a $91.7 million decrease in total gains on commodity hedges. Adjusted funds flow benefited from realized cash gains on our commodity hedges, which increased to $287.7 million in 2015 compared to $3.5 million in 2014.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2016				
Fourth Quarter	$ 217.4	$ 840.3	$ 3.49	$ 3.43
Third Quarter	188.3	(100.7)	(0.42)	(0.42)
Second Quarter	174.3	(168.5)	(0.77)	(0.77)
First Quarter	142.7	(173.7)	(0.84)	(0.84)
Total 2016	$ 722.7	$ 397.4	$ 1.75	$ 1.72
2015				
Fourth Quarter	$ 199.4	$ (625.0)	$ (3.03)	$ (3.03)
Third Quarter	228.3	(292.7)	(1.42)	(1.42)
Second Quarter	251.7	(312.5)	(1.52)	(1.52)
First Quarter	205.0	(293.2)	(1.42)	(1.42)
Total 2015	$ 884.4	$ (1,523.4)	$ (7.39)	$ (7.39)

Oil and natural gas sales, net of royalties decreased in 2016 compared to 2015 due to a decline in commodity prices along with lower production due to non-core asset divestments. During 2015, the impact of weak commodity prices was somewhat offset by increasing production. Net income increased in 2016 largely due to a decrease in non-cash asset impairments on our crude oil and natural gas assets and gains realized on asset divestments. The net loss reported in 2015 was a result of non-cash asset impairments and valuation allowances on our deferred tax asset related to the decrease in the twelve month average commodity prices.

ENVIRONMENT

We strive to carry out our activities and operations in compliance with all applicable regulations and best industry practices. Our operations are subject to laws and regulations concerning pollution, protection of the environment and the handling of hazardous materials and waste. We set corporate targets and mandates to improve environmental performance and execute environmental initiatives to become more energy efficient and to reduce, reuse and recycle water and minimize waste.

We have a Safety and Social Responsibility Policy ("S&SR Policy"), which articulates our commitment to health and safety, environmental, stakeholder engagement, and regulatory compliance. Our Board of Directors and President & Chief Executive Officer are ultimately accountable for ensuring compliance with the S&SR Policy. The Safety & Social Responsibility Committee of our Board of Directors (the "S&SR Committee") is responsible for overseeing our S&SR performance, ensuring there are adequate systems in place to support ongoing compliance, and to plan and execute the Company's activities in a safe and socially responsible manner.

We have established processes and programs designed to evaluate and minimize health, safety, and environmental risks, and strive for continuous improvement in our S&SR performance. We also actively participate in industry recognized programs that support our sustainability goals.

The S&SR Policy articulates our commitment to protecting the health and safety of all persons and communities involved in, or affected by, our business activities, and articulates our commitment to the environment. It states we endeavor to: (i) proactively manage our impact on the environment and consider innovative improvement opportunities; (ii) work to reduce our environmental impact in the areas in which we operate; (iii) improve our water and land use practices; (iv) limit the waste we generate; (v) prevent and manage environmental releases; (vi) provide transparent disclosure; and (vii) provide resources and training to meet our environmental commitments. Our commitment to building meaningful and transparent relationships, engaging with our stakeholders, and adhering to responsible development of resources and regulatory compliance is also stated.

We intend to continue to improve energy efficiencies and proactively manage our greenhouse gas emissions in compliance with applicable government regulations, including regulations enacted in British Columbia, Alberta and at the federal level in Canada and the U.S.

There are inherent risks of spills and pipeline leaks at our operating sites and clean-up costs may be significant. However, we have active site inspection, corrosion risk management and asset integrity management programs to help minimize this risk. In addition, we carry environmental insurance to help mitigate the cost of releases should they occur.

Some of our operations use hydraulic fracturing techniques, which involves the injection of pressurized fluids, sand, and small amounts of additives into a well bore. Government and regulatory agencies continue to frame regulations related to this process. We believe we are in compliance with all current government regulations and industry best practices in the U.S. and Canada.

The S&SR Committee regularly reviews health, safety, environmental and regulatory updates, and risks. At present, we believe we are, and expect to continue to be, in compliance with all material applicable environmental laws and regulations and we have included appropriate amounts in our capital expenditure budget to continue to meet our ongoing environmental obligations. However, increased capital and operating costs may be incurred if regulations in Canada or the U.S. impose more stringent compliance requirements.

Overall, we strive to operate in a socially responsible manner and believe our health, safety and environmental initiatives and performance confirm our ongoing commitment to environmental stewardship and the health and safety of our employees, contractors, and the public in the communities in which we operate.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with U.S. GAAP requires management to make certain judgments and estimates. Due to the timing of when activities occur compared to the reporting of those activities, management must estimate and accrue operating results and capital spending. Changes in these judgments and estimates could have a material impact on our financial results and financial condition.

Oil and Natural Gas Properties and Reserves

Enerplus follows the full cost method of accounting for oil and natural gas properties. The process of estimating reserves is critical in determining several accounting estimates including the Company's depletion, ceiling test, valuation allowance and gain or loss calculations. Estimating reserves requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and natural gas prices, operating costs and royalty burdens change. Reserves estimates impact net income through depletion, the determination of asset retirement obligation and the application of impairment tests. Revisions or changes in reserves estimates can have either a positive or a negative impact on net income.

Asset Impairment

Ceiling Test

Under the full cost method of accounting for Property, Plant and Equipment, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost centre ceiling, we are subject to a ceiling test write-down to the extent of such excess. These write-downs reduce net income and impact shareholders' equity in the period of occurrence and result in lower depletion expense in future periods. The volume and discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that further write-downs of our oil and natural gas properties could occur in the future. Under U.S. GAAP impairments are not reversed in future periods.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually at December 31. Goodwill and all other assets and liabilities are allocated to reporting units. To assess impairment, the carrying amount of each reporting unit is determined and compared to the fair value of the reporting unit. If the carrying amount of the reporting unit is higher than its related fair value then goodwill is written down to the reporting unit's implied fair value of goodwill. The fair value used in the impairment test is based on estimates of discounted future cash flows which involve assumptions of natural gas and liquids reserves, including commodity prices, future costs and discount rates.

Income Taxes

Management makes certain estimates in calculating deferred tax assets and liabilities, as well as income tax expense. These estimates often involve judgment regarding differences in the timing and recognition of revenue and expense for tax and financial reporting purposes as well as the tax basis of our assets and liabilities at the balance sheet date before tax returns are completed. Additionally, we must assess the likelihood we will be able to recover or utilize our deferred tax assets. We must record a valuation allowance against a deferred tax asset where all or a portion of that asset is not expected to be realized. In evaluating whether a valuation allowance should be applied, we consider evidence such as future taxable income, among other factors, both positive and negative. That determination involves numerous judgments and assumptions and includes estimating factors such as commodity prices, production and other operating conditions. If any of those factors, assumptions or judgments changes, the deferred tax asset could change, and in particular decrease in a period where we determine it is more likely than not that the asset will not be realized. Alternatively, a valuation allowance may be reversed where it is determined it is more likely than not that the asset will be realized.

Asset Retirement Obligation

Management calculates the asset retirement obligation based on estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and depleted over its useful life. There are uncertainties related to asset retirement obligations and the impact on the financial statements could be material as the eventual timing and costs for the obligations could differ from our estimates. Factors that could cause our estimates to differ include any changes to laws or regulations, reserves estimates, costs and technology.

Business Combinations

Management makes various assumptions in determining the fair value of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we, and independent evaluators, estimate oil and gas reserves and future prices of crude oil and natural gas.

Derivative Financial Instruments

We utilize derivative financial instruments to manage our exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices, foreign currency exchange rates, interest rates and counterparty credit risk.

RECENT U.S. GAAP ACCOUNTING AND RELATED PRONOUNCEMENTS

Refer to Note 2(o) in our Financial Statements for a detailed listing of Standards and Interpretations that were issued but not yet effective at December 31, 2016.

RISK FACTORS AND RISK MANAGEMENT

Commodity Price Risk

Our operating results and financial condition are dependent on the prices we receive for our crude oil, natural gas liquids, and natural gas production. These prices have fluctuated widely in response to a variety of factors including global and domestic supply and demand of crude oil, natural gas and natural gas liquids and economic conditions, including currency fluctuations, weather conditions, the ability to export oil and liquefied natural gas and natural gas liquids from North America and the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American crude oil, natural gas and natural gas liquids, political stability, transportation facilities, availability of processing, fractionation and refining facilities, the effect of world-wide energy conservation and greenhouse gas reduction measures, the price and availability of alternative fuels and existing and proposed changes to government regulations.

A further decline in crude oil or natural gas prices may have a material adverse effect on our operations, financial condition, borrowing ability, levels of reserves and resources and the level of expenditures for the development of our oil and natural gas reserves or resources. Certain oil or natural gas wells may become or remain uneconomic to produce if commodity prices are low, thereby impacting our production volumes, or our desire to market our production in unsatisfactory market conditions. Furthermore, we may be subject to the decisions of third party operators who, independently and using different economic parameters, may decide to curtail production.

We may use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of natural gas and crude oil price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains unhedged. Furthermore, we may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase. At February 23, 2017, approximately 63% of our 2017 forecasted net crude oil production is hedged and approximately 23% of our 2017 forecasted net natural gas production is hedged at price levels disclosed in the "Price Risk Management" section above. We have also hedged approximately 44% and 14%, respectively, of our forecasted 2017 net crude oil production in 2018 and 2019. Refer to the "Price Risk Management" section for further details on our price risk management program.

Risk of Increased Capital or Operating Costs

Higher capital or operating costs associated with our operations will directly impact our capital efficiencies and cash flow. Capital costs of completions, specifically the costs of proppant, and operating costs such as electricity, chemicals, supplies, energy services and labour costs, are a few of the costs that are susceptible to material fluctuation. Although we have a portion of our 2017 capital and operating costs protected with existing agreements, changing regulatory conditions, such as those in the U.S. requiring that certain raw materials be sourced from the U.S., may result in higher than expected supply costs.

Access to Field Services

Our ability to drill, complete and tie-in wells in a timely manner may be impacted by our access to service providers and supplies. Activity levels in each area may limit our access to these resources, restricting our ability to execute our capital plans in a timely manner. In addition, field service costs are influenced by market conditions and therefore can become cost prohibitive.

Although we have entered into service contracts for a portion of field services that will secure some of our drilling and fracturing services into 2017, access to field services and supplies in other areas of our business will continue to be subject to market availability.

Risk of Curtailed or Shut-in Production

Should we be required to curtail or shut-in production as a result of low commodity prices, environmental regulation or third party operational practices, it could result in a reduction to cash flow and production levels, and may result in additional operating and capital costs for the well to achieve prior production levels. In addition, curtailments or shut-ins may cause damage to the reservoir and may prevent us from achieving production and operating levels that were in place prior to the curtailment or shutting-in of the reservoir. With regard to curtailment, although regional pipeline capacity has increased over the past several years, sales gas infrastructure capacity in northeastern Pennsylvania remains constrained relative to the amount of natural gas that can be produced. Combined with the ongoing volatility in natural gas prices, this may result in continued discounted prices and an ongoing risk of price-related production curtailments.

Debt covenants may be exceeded with no ability to negotiate covenant relief

Declines in oil and natural gas prices may result in a significant reduction in earnings or cash flow, which could lead us to increase drawn amounts under the bank credit facility to carry out our operations and fulfill our obligations. Significant reductions to cash flow, significant increases in drawn amounts under the bank credit facility or significant reductions to proved reserves may result in a breach of our debt covenants. If a breach occurs, there is a risk that we may not be able to negotiate covenant relief with one or more of our lenders. Failure to comply with debt covenants or negotiate relief may result in our indebtedness under the bank credit facility and senior note agreements becoming immediately due and payable, which may have a material adverse effect on our operations and financial condition.

Our most restrictive debt covenant is a maximum senior debt to adjusted EBITDA ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At December 31, 2016, our senior debt to adjusted EBITDA ratio was 0.8x. We routinely review our compliance with covenants based on actual and forecasted results, and have the ability to adjust our capital spending levels and dividends or pursue asset divestments and equity issuances to comply with our covenants.

See the “Liquidity and Capital Resources” section for further information.

Counterparty and Joint Venture Credit Exposure

We are subject to the risk that the counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements as a result of liquidity requirements or insolvency. Low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure of our counterparties to perform their financial or operational obligations may adversely affect our operations and financial position. In addition to the usual delays in payment by purchasers of crude oil and natural gas, payments may also be delayed by, among other things: (i) capital or liquidity constraints experienced by our counterparties, including restrictions imposed by lenders; (ii) accounting delays or adjustments for prior periods; (iii) delays in the sale or delivery of products or delays in the connection of wells to a gathering system; (iv) weather related delays, such as freeze-offs, flooding and premature thawing; (v) blow-outs or other accidents; or (vi) recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for these expenses. Any of these delays could reduce the amount of our cash flow and the payment of cash dividends to our shareholders in a given period and expose us to additional third party credit risks.

A credit review process is in place to assess and monitor our counterparties' credit worthiness on a regular basis. This includes reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted we attempt to obtain financial assurances such as letters of credit, parental guarantees, or third party insurance to mitigate our counterparty risk. In addition, we monitor our receivables against a watch list of publicly traded companies that have high debt-to-cash flow ratios or fully drawn bank facilities and, where possible, take our production in kind rather than relying on third party operators. In certain instances, we may be able to aggregate all amounts owing to each other and settle with a single net amount.

See the “Liquidity and Capital Resources” section for further information.

Oil and Gas Reserves and Resources Risk

The value of our company is based on, among other things, the underlying value of our oil and gas reserves and resources. Geological and operational risks along with product price forecasts can affect the quantity and quality of reserves and resources and the cost of ultimately recovering those reserves and resources. Lower crude oil, natural gas liquids, and natural gas prices along with lower development capital spending associated with certain projects may increase the risk of write-downs for our oil and gas property investments. Changes in reporting methodology as well as regulatory practices can result in reserves or resources write-downs.

Each year, independent reserves engineers evaluate the majority of our proved and probable reserves as well as evaluating or auditing the resources attributable to a significant portion of our undeveloped land. All reserves information, including our U.S. reserves, has been prepared in accordance with NI 51-101 standards. For U.S. GAAP accounting purposes, our proved reserves are estimated to be technically the same as our proved reserves prepared under NI 51-101 and have been adjusted for the effects of SEC constant prices. Independent reserves evaluations have been conducted on approximately 86% of the total proved plus probable net present value (discounted at 10% and using NI 51-101 standards) of our reserves at December 31, 2016. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 48% of our Canadian reserves and reviewed the internal evaluation completed by Enerplus on the remaining portion. McDaniel also evaluated 100% of the reserves associated with our U.S. tight oil assets. Netherland, Sewell & Associates, Inc. ("NSAI") evaluated 100% of our U.S. Marcellus shale gas assets.

The evaluations of best estimate development pending contingent resources associated with a portion of our Canadian waterflood properties and our Fort Berthold assets were conducted by Enerplus' qualified reserves evaluators and audited by McDaniel. NSAI evaluated our Marcellus shale gas best estimate development pending contingent resources.

The Reserves Committee and the Board of Directors has reviewed and approved the reserves and resources reports of the independent evaluators.

Risk of Impairment of Oil and Gas Properties and Deferred Tax Assets

Under U.S. GAAP, the net capitalized cost of oil and gas properties, net of deferred income taxes, is limited to the present value of after-tax future net revenue from proved reserves, discounted at 10%, and based on the unweighted average of the closing prices for the applicable commodity on the first day of the twelve months preceding the issuer's reporting date. The amount by which the net capitalized costs exceed the discounted value will be charged to net income.

Under U.S. GAAP, the net deferred tax assets is limited to the estimate of future taxable income resulting from existing properties. We estimate our future taxable income based on before-tax future net revenue from proved reserves, undiscounted, using benchmark 2017 forward prices on December 30, 2016, held constant and adjusted for other significant items affecting taxable income. The amount by which the gross deferred tax assets exceed the estimate of future taxable income will be charged to net income, however these amounts can be reversed in future periods if future taxable income increases.

In 2016 we reported a non-cash impairment of $301.2 million on our crude oil and natural gas assets, compared to $1,352.4 million in 2015, and a non-cash recovery of $234.8 million due in part to the reversal of a portion of the valuation allowance recorded on our deferred tax asset in 2015. While these amounts do not affect cash flow, the volatility in earnings may be viewed unfavourably in the market. There is risk of further impairment on our oil and gas properties and deferred tax asset if commodity prices weaken during 2017. Additional write-downs may lead to a breach of our Total Debt to Capitalization covenant under the bank credit facility, and we may not be able to renegotiate our covenants.

Access to Transportation and Processing Capacity

Market access for crude oil, NGLs and natural gas production in Canada and the U.S. is dependent on our ability to obtain transportation capacity on third party pipelines and rail as well as access to processing facilities. Newer resource plays, such as the North Dakota Bakken and the Marcellus shale gas, generally experience a sharp production increase in the area which could exceed the existing capacity of the gathering, pipeline, processing or rail infrastructure. While third party pipelines, processors and independent rail operators generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of capacity. There are occasionally operational reasons for curtailing transportation and processing capacity. Accordingly, there can be periods where transportation and processing capacity is insufficient to accommodate all of the production from a given region, causing added expense and/or volume curtailments for all shippers. Our assets are concentrated in specific regions with varying levels of government that could limit or ban the shipping of commodities by truck, pipeline or rail. Special interest groups could also oppose infrastructure development resulting in a delay or even the cancellation of the required infrastructure, further impeding our ability to produce and market our products. Additionally, the transportation of crude oil by rail may come under closer scrutiny by government regulatory agencies in Canada and the U.S.. As a result, there may be incremental costs associated with transporting crude oil by rail, and there is a risk that access to rail transport may be constrained, depending upon any changes made to existing rail transport regulations.

We continuously monitor this risk for both the short and longer term through dialogue and review with the third party pipelines and other market participants. Where available and commercially appropriate, given the production profile and commodity, we attempt to mitigate transportation and processing risk by contracting for firm pipeline or processing capacity or using other means of transportation, including truck or selling to third parties that have access to rail capacity.

Foreign Currency Exposure

We have exposure to fluctuations in foreign currency as most of our senior notes are denominated in U.S. dollars. Our U.S. operations are directly exposed to fluctuations in the U.S. dollar when translated to our Canadian dollar denominated financial statements. We also have indirect exposure to fluctuations in foreign currency as our crude oil sales and a portion of our natural gas sales are based on U.S. dollar indices. Our oil and gas revenues are positively impacted when the Canadian dollar weakens relative to the U.S. dollar. However, our U.S. capital spending, transportation and operating costs, interest expense and debt repayments are negatively impacted with a weak Canadian dollar.

Currently, we do not have any foreign exchange contracts in place to hedge our foreign exchange exposure. However, we continue to monitor fluctuations in foreign exchange and the impact on our operations.

Ability to Divest Properties

Recent regulatory changes in Alberta and Saskatchewan have increased the minimum corporate liability rating required of purchasers of crude oil and natural gas properties. As a result, the potential number of parties able to acquire our non-core assets has been reduced, we may not be able to obtain full value for such assets, or transactions may involve greater risk and complexity.

Anticipated Benefits of Acquisitions or Divestments

From time to time, we may acquire additional crude oil and natural gas properties and related assets. Achieving the anticipated benefits of such acquisitions will depend in part on successfully consolidating functions and integrating operations, procedures, and personnel in a timely and efficient manner, as well as our ability to realize the anticipated growth opportunities from combining and integrating the acquired assets and properties into our existing business. These activities will require the dedication of substantial management effort, time, capital, and other resources, which may divert management's focus, capital and other resources from other strategic opportunities and operational matters during this process. The risk factors specified in this MD&A relating to the crude oil and natural gas business and our operations, reserves and resources apply equally to future properties or assets that we may acquire. We generally conduct due diligence in connection with acquisitions, but there is no assurance that we will identify all the potential risks and liabilities related to such properties.

When acquiring assets, we are subject to inherent risks associated with predicting the future performance of those assets. We may make certain estimates and assumptions respecting the characteristics of the assets we acquire, that may not be realized over time. As such, assets acquired may not possess the value we attribute to them, which could adversely impact our future cash flows. To the extent that we make acquisitions with higher growth potential, the higher risks often associated may result in increased chances that actual results may vary from our initial estimates. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods, approaches, and assumptions than those of our engineers, and these initial assessments may differ significantly from our subsequent assessments.

Certain acquisitions, and in particular acquisitions of higher risk/higher growth assets and the development of those acquired assets, may require capital expenditures and we may not receive cash flow from operations from these acquisitions for several years, or in amounts less than anticipated. Accordingly, the timing and amount of capital expenditures may adversely affect our cash flow.

We may also seek to divest of properties and assets from time to time. These divestments may consist of non-core properties or assets, or may consist of assets or properties that are being monetized to fund alternative projects or development or debt repayments. There can be no assurance that we will be successful, that we will realize the amount of desired proceeds, or that such divestments will be viewed positively by the financial markets. Divestments may negatively affect our results of operations or the trading price of our common shares. In addition, although divestments typically transfer future obligations to the buyer, we may not be exempt from certain future obligations, including abandonment and reclamation, which may have an adverse effect on our operations and financial condition.

Access to Capital Markets

Our access to capital has allowed us to fund a portion of our acquisitions and development capital program through issuance of equity and debt in past years. Continued access to capital is dependent on our ability to optimize our existing assets and to demonstrate the advantages of the acquisition or development program that we are financing at the time, as well as investors' view of the oil and gas industry overall. We may not be able to access the capital markets in the future on terms favorable to us, or at all. Our continued access to capital markets is dependent on corporate performance and investor perception of future performance (both corporately and for the oil and gas sector in general).

We are required to assess our "foreign private issuer" status under U.S. securities laws on an annual basis. If we were to lose our status as a "foreign private issuer" under U.S. securities laws, we may have restricted access to capital markets for a period of time until the required approvals are in place from the U.S. Securities and Exchange Commission.

Regulatory Risk & Greenhouse Gas Emissions

Government royalties, environmental laws and regulatory requirements can have a significant financial and operational impact on us. As an oil and gas producer, we operate under federal, provincial, state and municipal legislation and regulation that govern such matters as royalties, land tenure, prices, production rates, various environmental protection controls, well and facility design and operation, income, and the exportation of crude oil, natural gas and other products. We may be required to apply for regulatory approvals in the ordinary course of business. To the extent that we fail to comply with applicable government regulations or regulatory approvals, we may be subject to compliance and enforcement actions that are either remedial or punitive to deter future noncompliance. Such actions include fines or fees, notices of noncompliance, warnings, orders, administrative sanctions, and prosecution.

Government regulations may be changed from time to time in response to economic or political conditions, including the election of new state, provincial or federal leaders. Additionally, our entry into new jurisdictions or adoption of new technology may attract additional regulatory oversight which could result in higher costs or require changes to proposed operations. Canadian and U.S. governments have enhanced their oversight and reporting obligations associated with fracturing procedures and increased their scrutiny of the usage and disposal of chemicals and water used in fracturing procedures. Additionally, various levels of Canadian and U.S. governments are considering or have implemented legislation to reduce emissions of greenhouse gases, including volatile organic compounds ("VOC"), and methane gas emissions. Specifically, the Province of Alberta instituted the Climate Leadership Act in 2016, which, starting in 2023, sets a carbon tax of $30 per tonne of carbon dioxide equivalent emissions that occur from our Alberta operations. The Province of Alberta has also established a reduction goal of 45% for methane gas emissions for our Alberta operations by 2025. The Act will likely increase electrical use costs for our Alberta operations as a carbon tax for electrical use comes into effect in 2017.

The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations could negatively impact the development of oil and gas properties and assets, reduce demand for crude oil and natural gas or impose increased costs on oil and gas companies including taxes, fees or other penalties.

Although we have no control over these regulatory risks, we continuously monitor changes in these areas by participating in industry organizations, conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on our financial and operating results.

Specifically, with respect to regulations for the reduction of greenhouse gas emissions, the Canadian federal government continues to seek alignment for the regulations to be issued in Canada with those of the U.S.. Accordingly, while we continue to prepare to meet the potential requirements, the actual cost impact and its materiality to our business remains uncertain on a federal level.

Risk of Public Opposition and Activism

The oil and natural gas industry elicits concerns over climate change, as well as general public opposition to the industry. As a result, industry participants such as Enerplus may be subject to increased public activism, as well as extensive environmental regulation. Activist activity may result in increased costs due to delays or damage.

The expansion of our business activities, both geographically and with a new focus on exploration, may draw increased attention from shareholder activists who oppose our strategy, which could have an adverse effect on market value. Our ongoing participation in the Canadian and U.S. capital markets may expose us to greater risk of class action lawsuits related to securities law, title, contractual and environmental matters.

Health, Safety and Environmental Risk

Health, safety and environmental risks impact our workforce and operating costs and result in the enhancement of our business practices and standards. There may be risks associated with hydraulic fracturing including the risk of induced seismicity with the injection of fluid into any reservoir. We expect regulatory frameworks will be amended or continue to emerge in this regard. Although Enerplus proactively mitigates perceived risks involved in the hydraulic fracturing process, increased capital and operating costs may be incurred if regulations in Canada or the U.S. impose more stringent compliance requirements surrounding hydraulic fracturing. The impact of such changes on our business could increase our cost of compliance and the risk of litigation and environmental liability.

We have an S&SR department that develops standards and systems to manage health, safety and environmental risks, and regulatory compliance. The S&SR Committee of our Board of Directors is responsible for overseeing the organization's health, safety and environmental performance and ensuring there are adequate systems in place to support ongoing compliance, and to plan and execute activities in a safe and socially responsible manner. We have insurance to cover a portion of our property losses, liability and business interruption. At present, we believe we are, and expect to continue to be, in compliance with all material applicable environmental laws and regulations and have included appropriate amounts in our capital expenditure budget to continue to meet our ongoing environmental obligations.

Changes in Income Tax and Other Laws

Income tax, other laws or government incentive programs relating to the oil and gas industry may be changed in a manner that adversely affects us or our security holders. Canadian, U.S. and foreign tax authorities may interpret applicable tax laws, tax treaties or administrative positions differently than we do or may disagree with how we calculate our income for tax purposes in a manner which is detrimental to us and our security holders.

We monitor developments with respect to pending legal changes and work with the industry and professional groups to ensure that our concerns with any changes are made known to various government agencies. We obtain confirmation from independent legal counsel and advisors with respect to the interpretation and reporting of material transactions.

Production Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Our ability to replace production depends on our success in acquiring new land, reserves and/or resources and developing existing reserves and resources. Acquisitions of oil and gas assets will depend on our assessment of value at the time of acquisition and ability to secure the acquisitions generally through a competitive bid process.

Acquisitions and our development capital program are subject to investment guidelines, due diligence and review. Major acquisitions and our annual capital development budget are approved by the Board of Directors and where appropriate, independent reserve engineer evaluations are obtained.

Title Defects or Litigation

Unforeseen title defects or litigation may result in a loss of entitlement to production, reserves and resources.

Although we conduct title reviews prior to the purchase of assets these reviews do not guarantee that an unforeseen defect in the chain of title will not arise. We maintain good working relationships with our industry partners; however, disputes may arise from time to time with respect to ownership of rights of certain properties or resources.

Interest Rate Exposure

We have exposure to movements in interest rates and credit markets as changing interest rates affect our borrowing costs and value of investments such as our shares as well as other equity investments.

We monitor the interest rate forward market and have fixed the interest rate on approximately 97% of our debt through our senior notes.

Cyber Security Risks

We are subject to a variety of information technology and system risks as part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach and destruction or interruption of our information technology systems by third parties or insiders. Although we have security measures and controls in place that are designed to mitigate these risks, a breach of our security and/or a loss of information could occur and result in a loss of material and confidential information, reputation damage, a breach in privacy laws and disruption to business activities. The significance of any such event is difficult to quantify, but may be material in certain circumstances and could have a material effect on our business, financial condition and results of operations.

ADJUSTED FUNDS FLOW SENSITIVITY

The sensitivities below reflect all commodity contracts listed in Note 15 to the Financial Statements and are based on 2017 guidance price levels. To the extent crude oil and natural gas prices change significantly from current levels, the sensitivities will no longer be relevant.

Sensitivity Table	Estimated Effect on 2017 Adjusted Funds Flow per Share(1)
Change of $0.50 per Mcf in the price of NYMEX natural gas	$ 0.21
Change of US$5.00 per barrel in the price of WTI crude oil	$ 0.25
Change of 1,000 BOE/day in production	$ 0.03
Change of $0.01 in the US/CDN exchange rate	$ 0.02
Change of 1% in interest rate	$ 0.03

(1) Assumes 240.5 million weighted average shares outstanding.

2017 GUIDANCE

A summary of our previously released 2017 guidance is below, including our updated Bakken crude oil differential of US$4.50/bbl below WTI (from $6.00/bbl previously). This guidance includes the impact of the 2016 fourth quarter non-operated North Dakota sale and Canadian waterflood purchase. No additional potential acquisitions or divestments have been included. This guidance is based on a WTI crude oil price of US$55.00/bbl, NYMEX natural gas price of US$3.00/Mcf, AECO natural gas price of $2.75/GJ and a US/CDN exchange rate of 1.35.

Summary of 2017 Expectations	Target
Capital spending	$450 million
Average annual production	86,000 – 90,000 BOE/day
Fourth quarter average production	92,000 – 97,000 BOE/day
Average annual crude oil and natural gas liquids production	40,000 – 43,000 bbls/day
Fourth quarter average annual crude oil and natural gas liquids production	45,000 – 50,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	23%
Operating expenses	$7.85/BOE
Transportation costs	$3.90/BOE
Cash G&A expenses	$1.80/BOE

2017 Differential/Basis Outlook(1)	
U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(4.50)/bbl
Marcellus basis (compared to NYMEX natural gas)	US$(0.90)/Mcf

(1) Before field transportation costs

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 expenses and transportation costs.

Calculation of Netback	**Year ended December 31,**		
($ millions)	**2016**	**2015**	**2014**
Oil and natural gas sales, net of royalties	$ 722.7	$ 884.4	$ 1,526.2
Less:			
Production taxes	(37.4)	(50.9)	(81.5)
Cash operating expenses(1)	(249.0)	(340.1)	(347.3)
Transportation costs	(107.1)	(114.7)	(101.2)
Netback before hedging	$ 329.2	$ 378.7	$ 996.2
Cash gains/(losses) on derivative instruments	80.3	287.7	3.5
Netback after hedging	$ 409.5	$ 666.4	$ 999.7

(1) Operating costs adjusted to exclude non-cash gains on fixed price electricity swaps of $1.1 million in 2016 and non-cash losses of $0.4 million in 2015 and $1.3 million in 2014.

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

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	**Year ended December 31,**		
($ millions)	**2016**	**2015**	**2014**
Cash flow from operating activities	$ 312.3	$ 465.3	$ 787.2
Asset retirement obligation expenditures	8.4	14.9	19.4
Changes in non-cash operating working capital	(15.1)	12.9	52.4
Adjusted funds flow	$ 305.6	$ 493.1	$ 859.0

"Net debt to adjusted funds flow ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The net debt to adjusted funds flow ratio is calculated as total debt net of cash, including restricted cash, divided by a trailing 12 months of adjusted funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted 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 adjusted funds flow.

Calculation of Adjusted Payout Ratio	**Year ended December 31,**		
($ millions)	**2016**	**2015**	**2014**
Dividends(1)	$ 35.4	$ 132.0	$ 199.3
Capital and office expenditures	210.6	497.9	818.0
Sub-total	$ 246.0	$ 629.9	$ 1,017.3
Adjusted funds flow	$ 305.6	$ 493.1	$ 859.0
Adjusted payout ratio (%)	80%	128%	118%

(1) Cash dividends exclude stock dividend plan proceeds in 2014. The stock dividend plan was suspended during 2014.

"Adjusted EBITDA" is used by Enerplus and its lenders to determine compliance with financial covenants under its bank credit facility and outstanding senior notes.

Reconciliation of Net Income to Adjusted EBITDA[1]

($ millions)		December 31, 2016
Net income/(loss)	$	397.4
Add:		
Interest expense		45.4
Current and deferred tax expense/(recovery)		(237.2)
DD&A and asset impairment charges		630.1
Other non-cash charges[2]		91.5
Sub-total	$	927.2
Adjustment for material acquisitions and divestments[3]		(6.2)
Adjusted EBITDA	$	921.0

(1) Adjusted EBITDA is calculated based on the trailing four quarters.
(2) Includes the change in fair value of commodity derivatives, fixed price electricity swaps and equity swaps, non-cash SBC, and unrealized foreign exchange gains/losses.
(3) EBITDA is adjusted for material acquisitions or divestments during the period with net proceeds greater than $50 million as if that acquisition or divestment had been made at the beginning of the period.

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 "debt net of cash", "senior debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "maximum debt to consolidated present value of total proved reserves" and "adjusted 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.

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal controls over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at December 31, 2016, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on January 1, 2016 and ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

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

This MD&A contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "plans", "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 2017 total and fourth quarter 2017 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 adjusted funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management program in 2017 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2017 and impact thereof on our production levels and land holdings; potential future asset and goodwill impairments, as well as relevant factors that may affect such impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes and to negotiate relief if required; our future acquisitions and dispositions, expecting timing thereof and 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 and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to negotiate debt covenant relief under our bank credit facility and outstanding senior notes if required; the availability of third party services; and the extent of our liabilities. In addition, our 2017 guidance contained in this MD&A is based on the following: a WTI price of US$55.00/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.75/GJ and a USD/CDN exchange rate of 1.35. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued low commodity prices environment or further decline of commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our AIF and Form 40-F as at December 31, 2016).

The purpose of our adjusted funds flow sensitivity is to assist readers in understanding our expected and targeted financial results, and this information may not be appropriate for other purposes. The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2016, our internal control over financial reporting is effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2016, has been audited by Deloitte LLP, the Independent Registered Public Accounting Firm, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2016.

Ian C. Dundas
President and
Chief Executive Officer

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

Calgary, Alberta
February 24, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Enerplus Corporation

We have audited the internal control over financial reporting of Enerplus Corporation and subsidiaries (the "Company") as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016 of the Company and our report dated February 24, 2017 expressed an unmodified/unqualified opinion on those financial statements.

Deloitte LLP

Chartered Professional Accountants

February 24, 2017
Calgary, Canada

Management's Responsibility for Financial Statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Corporation have been prepared within reasonable limits of materiality and in accordance with accounting principles generally accepted in the United States of America. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 23, 2017. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

The consolidated financial statements have been examined by Deloitte LLP, Independent Registered Public Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America. The Report of Independent Registered Public Accounting Firm outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the Independent Registered Public Accounting Firm and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Company.

Ian C. Dundas

President and
Chief Executive Officer

Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 24, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Enerplus Corporation

We have audited the accompanying consolidated financial statements of Enerplus Corporation and subsidiaries (the "Company"), which comprise the consolidated balance sheets as at December 31, 2016, and December 31, 2015, and the consolidated statements of income/(loss) and comprehensive income/(loss), consolidated statements of changes in shareholders' equity, and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2016, and the notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enerplus Corporation and subsidiaries as at December 31, 2016, and December 31, 2015, and their financial performance and their cash flows for each of the years in the three-year period ended December 31, 2016 in accordance with accounting principles generally accepted in the United States of America.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte LLP

Chartered Professional Accountants

February 24, 2017
Calgary, Canada

Consolidated Balance Sheets

(CDN$ thousands)	Note	December 31, 2016	December 31, 2015
Assets			
Current assets			
Cash		$ 1,257	$ 7,498
Restricted cash	2(f)	392,048	—
Accounts receivable	3	115,368	132,156
Derivative financial assets	15	—	71,438
Other current assets		6,721	9,953
		515,394	221,045
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	726,452	1,166,587
Other capital assets, net	4	11,978	19,686
Property, plant and equipment		738,430	1,186,273
Goodwill	2(g)	651,663	657,831
Deferred income tax asset	13	733,363	516,085
Total Assets		$ 2,638,850	$ 2,581,234
Liabilities			
Current liabilities			
Accounts payable	6	$ 184,534	$ 239,950
Dividends payable		2,405	6,196
Current portion of long-term debt	7	29,539	—
Derivative financial liabilities	15	28,615	4,100
		245,093	250,246
Derivative financial liabilities	15	12,266	3,193
Long-term debt	7	739,286	1,223,682
Asset retirement obligation	8	181,700	206,359
		933,252	1,433,234
Total Liabilities		1,178,345	1,683,480
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: December 31, 2016 - 240 million shares			
December 31, 2015 - 206 million shares	14	3,365,962	3,133,524
Paid-in capital		73,783	56,176
Accumulated deficit		(2,332,641)	(2,694,618)
Accumulated other comprehensive income/(loss)		353,401	402,672
		1,460,505	897,754
Total Liabilities & Shareholders' Equity		$ 2,638,850	$ 2,581,234
Commitments, Contingencies and Guarantees	16		

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

Approved on behalf of the Board of Directors:

Elliott Pew
Director

Robert B. Hodgins
Director

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

For the year ended December 31 (CDN$ thousands)	Note	2016	2015	2014
Revenues				
Oil and natural gas sales, net of royalties	9	$ 722,732	$ 884,392	$ 1,526,194
Commodity derivative instruments gain/(loss)	15	(29,397)	142,724	234,373
		693,335	1,027,116	1,760,567
Expenses				
Operating		247,917	340,483	348,596
Transportation		107,147	114,691	101,183
Production taxes		37,417	50,899	81,522
General and administrative	10	86,319	103,870	105,041
Depletion, depreciation and accretion		328,964	508,179	567,642
Asset impairment	5	301,171	1,352,428	—
Interest	11	45,443	66,456	62,820
Foreign exchange (gain)/loss	12	(40,526)	173,933	57,090
Gain on divestment of assets	4	(559,235)	—	—
Gain on prepayment of senior notes	7	(19,270)	—	—
Other expense /(income)		(2,230)	7,055	(231)
		533,117	2,717,994	1,323,663
Income/(Loss) Before Taxes		160,218	(1,690,878)	436,904
Current income tax expense/(recovery)	13	(2,351)	(16,887)	4,998
Deferred income tax expense/(recovery)	13	(234,847)	(150,588)	132,830
Net Income/(Loss)		$ 397,416	$ (1,523,403)	$ 299,076
Other Comprehensive Income/(Loss)				
Change in cumulative translation adjustment		(49,271)	307,194	143,817
Changes due to marketable securities (net of tax)				
Unrealized gain/(loss)		—	—	(145)
Realized (gain)/loss reclassified to net income		—	—	2,503
Other Comprehensive Income/(Loss)		(49,271)	307,194	146,175
Total Comprehensive Income/(Loss)		$ 348,145	$ (1,216,209)	$ 445,251
Net Income/(Loss) per Share				
Basic	14	$ 1.75	$ (7.39)	$ 1.46
Diluted	14	$ 1.72	$ (7.39)	$ 1.44

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

Consolidated Statements of Changes in Shareholders' Equity

For the year ended December 31 (CDN$ thousands)	**2016**	**2015**	**2014**
Share Capital			
Balance, beginning of year	$ 3,133,524	$ 3,120,002	$ 3,061,839
Public offering (net of issue costs)	223,031	—	—
Share-based compensation – settled	9,407	10,050	—
Stock Option Plan – cash	—	3,205	31,350
Stock Option Plan – exercised	—	267	4,978
Stock Dividend Plan	—	—	21,835
Balance, end of year	$ 3,365,962	$ 3,133,524	$ 3,120,002
Paid-in Capital			
Balance, beginning of year	$ 56,176	$ 46,906	$ 38,398
Share-based compensation – settled	(9,407)	(10,050)	—
Share-based compensation – non-cash	27,014	19,587	13,486
Stock Option Plan – exercised	—	(267)	(4,978)
Balance, end of year	$ 73,783	$ 56,176	$ 46,906
Accumulated Deficit			
Balance, beginning of year	$ (2,694,618)	$ (1,039,260)	$ (1,117,238)
Net income/(loss)	397,416	(1,523,403)	299,076
Dividends	(35,439)	(131,955)	(221,098)
Balance, end of year	$ (2,332,641)	$ (2,694,618)	$ (1,039,260)
Accumulated Other Comprehensive Income/(Loss)			
Balance, beginning of year	$ 402,672	$ 95,478	$ (50,697)
Change in cumulative translation adjustment	(49,271)	307,194	143,817
Changes due to marketable securities (net of tax)			
Unrealized gain/(loss)	—	—	(145)
Realized (gain)/loss reclassified to net income	—	—	2,503
Balance, end of year	$ 353,401	$ 402,672	$ 95,478
Total Shareholders' Equity	$ 1,460,505	$ 897,754	$ 2,223,126

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

Consolidated Statements of Cash Flows

For the year ended December 31 (CDN$ thousands)	**Note**	**2016**	**2015**	**2014**
Operating Activities				
Net income/(loss)		$ 397,416	$ (1,523,403)	$ 299,076
Non-cash items add/(deduct):				
Depletion, depreciation and accretion		328,964	508,179	567,642
Asset impairment	5	301,171	1,352,428	—
Changes in fair value of derivative instruments	15	105,026	169,336	(242,038)
Deferred income tax expense/(recovery)	13	(234,847)	(150,588)	132,830
Foreign exchange (gain)/loss on debt and working capital	12	(40,634)	160,791	68,202
Share-based compensation	14	27,014	19,587	13,486
Gain on the divestment of assets	4	(559,235)	—	2,798
Gain on prepayment of senior notes	7	(19,270)	—	—
Derivative settlement of foreign exchange swaps	7	—	(43,229)	17,024
Asset retirement obligation expenditures	8	(8,390)	(14,935)	(19,409)
Changes in non-cash operating working capital	18	15,075	(12,830)	(52,414)
Cash flow from operating activities		312,290	465,336	787,197
Financing Activities				
Proceeds from the issuance of shares (net of issue costs)	14	220,410	3,205	31,350
Cash dividends	14	(35,439)	(131,955)	(199,263)
Increase/(decrease) in bank credit facility		(55,999)	6,626	(136,918)
Proceeds/(repayment) of senior notes	7	(335,400)	(103,198)	167,497
Derivative settlement on senior notes	7	—	43,229	(17,024)
Changes in non-cash financing working capital		(3,791)	(12,320)	263
Cash flow from/(used in) financing activities		(210,219)	(194,413)	(154,095)
Investing Activities				
Capital and office expenditures		(210,611)	(497,875)	(817,968)
Property and land acquisitions		(126,126)	(9,552)	(18,491)
Property divestments	4	670,364	286,614	203,576
Increase in restricted cash		(392,048)	—	—
Sale of marketable securities		—	—	13,300
Changes in non-cash investing working capital		(49,472)	(47,586)	(17,449)
Cash flow from/(used in) investing activities		(107,893)	(268,399)	(637,032)
Effect of exchange rate changes on cash		(419)	2,938	2,976
Change in cash		(6,241)	5,462	(954)
Cash, beginning of year		7,498	2,036	2,990
Cash, end of year		$ 1,257	$ 7,498	$ 2,036

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

Notes to Consolidated Financial Statements

1) REPORTING ENTITY

These annual audited Consolidated Financial Statements ("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 Consolidated Financial Statements were authorized for issue by the Board of Directors on February 23, 2017.

2) SIGNIFICANT ACCOUNTING POLICIES

The following significant accounting policies are presented to assist the reader in evaluating these Consolidated Financial Statements and, together with the following notes, are an integral part of the Consolidated Financial Statements.

a) Basis of Preparation

Enerplus' Consolidated Financial Statements have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). These Consolidated Financial Statements present Enerplus' financial position as at December 31, 2016 and 2015 and results of operations for the years ended December 31, 2016, and the 2015 and 2014 comparative years. Certain prior period amounts have been restated to conform with current period presentation.

i. Reporting Currency

These Consolidated Financial Statements are presented in Canadian dollars, which is Enerplus' reporting currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand unless otherwise indicated.

ii. Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows, depreciation, depletion and accretion ("DD&A"), impairment, asset retirement obligations, income taxes, income tax asset values, impairment assessments of goodwill and the fair value of derivative instruments. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions. In the opinion of management, these Consolidated Financial Statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

iii. Basis of Consolidation

These Consolidated Financial Statements include the accounts of Enerplus and its subsidiaries. Intercompany balances and transactions are eliminated on consolidation. Interests in jointly controlled oil and natural gas assets are accounted for following the concept of undivided interest, whereby Enerplus' proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

The acquisition method of accounting is used to account for acquisitions of companies that meet the definition of a business under U.S. GAAP. The cost of an acquisition is measured as the fair value of the assets transferred, equity instruments issued and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date.

b) Revenue

Revenue associated with the sale of oil and natural gas is recognized when title passes from the Company to its customers if collectability is reasonably certain and the sales price is determinable. Revenue is measured at the fair value of the consideration received or receivable based on price, volumes delivered and contractual delivery points. Realized gains and losses from commodity price risk management activities are recognized in revenue when the contract is settled. Unrealized gains and losses on commodity price risk management activities are recognized in revenue based on the changes in fair value of the contracts at the end of the respective reporting period.

c) Transportation

Enerplus generally sells oil and natural gas under two types of agreements which are common in our industry. Both types of agreements include a transportation charge. One is a net-back arrangement, under which the Company sells crude oil or natural gas at the wellhead and collects a price, net of the transportation incurred by the purchaser. In this case, sales are recorded at the price received from the purchaser, net of transportation costs.

Under the other arrangement, Enerplus sells crude oil or natural gas at a specific delivery point, pays transportation to a third party and receives proceeds from the purchaser with no transportation deduction. In this case transportation costs are recorded as transportation expense on the Consolidated Statements of Income/(Loss). Due to these two distinct selling arrangements, Enerplus' computed realized prices, before the impact of derivative instruments, include revenues which are reported under two separate bases.

d) Oil and Natural Gas Properties

Enerplus uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs incurred in finding oil and natural gas reserves are capitalized, including general and administrative costs directly attributable to these activities. These costs are recorded on a country-by-country cost centre basis as oil and natural gas properties subject to depletion ("full cost pool"). Costs associated with production and general corporate activities are expensed as incurred.

The net carrying value of both proved and unproved oil and natural gas properties is depleted using the unit of production method using proved reserves, as determined using a constant price assumption of the simple average of the preceding twelve months' first-day-of-the-month commodity prices ("SEC prices"). The depletion calculation takes into account estimated future development costs necessary to bring those reserves into production.

Under full cost accounting, a ceiling test is performed on a cost centre basis. Enerplus limits capitalized costs of proved and unproved oil and natural gas properties, net of accumulated depletion and deferred income tax liabilities, to the estimated future net cash flows from proved oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties ("the ceiling"). If such capitalized costs exceed the ceiling, a write-down equal to that excess is recorded as a non-cash charge to net income. A write-down is not reversed in future periods even if higher oil and natural gas prices subsequently increase the ceiling.

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

e) Other Capital Assets

Other capital assets are recorded at historical cost, net of depreciation, and include furniture, fixtures, leasehold improvements and computer equipment. Depreciation is calculated on a straight-line basis over the estimated useful life of the respective asset. The cost of repairs and maintenance is expensed as incurred.

f) Restricted Cash

Restricted cash on the Consolidated Balance Sheets as of December 31, 2016 consists of proceeds from the sale of our non-operated North Dakota properties. The funds have been deposited with a qualified intermediary through two financial institutions and which is restricted for application towards future acquisitions to facilitate a potential like-kind exchange transaction for U.S. federal income tax purposes. The funds continue to be held in escrow and will remain there for a period of up to 180 days from the closing date of the sale. Counterparty credit risk related to this restricted cash is managed through the use of a qualified trust account, whereby the assets held in trust must be segregated from the financial institution's assets, and in the event of its bankruptcy, the funds would not be subject to payments to the creditors of the financial institution.

g) Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. The portion of goodwill that relates to U.S. operations fluctuates due to changes in foreign exchange rates. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

Impairment testing is performed on an annual basis or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus performs a qualitative assessment by evaluating potential indicators of impairment, and if it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss). For the purposes of goodwill impairment testing, Enerplus has one consolidated reporting unit.

During the 2016 and 2015 years there were no additions or impairments to goodwill.

h) Asset Retirement Obligations

Enerplus' oil and natural gas operating activities give rise to dismantling, decommissioning and site remediation activities. Enerplus recognizes a liability for the estimated present value of the future asset retirement obligation liability at each balance sheet date. The associated asset retirement cost is capitalized and amortized over the same period as the underlying asset. Changes in the estimated liability and related asset retirement cost can arise as a result of revisions in the estimated amount or timing of cash flows.

Depletion of asset retirement costs and increases in asset retirement obligations resulting from the passage of time are recorded to depreciation, depletion and accretion and charged against net income in the Consolidated Statements of Income/(Loss).

i) Income Tax

Enerplus uses the liability method of accounting for income taxes. Deferred income tax assets and liabilities are recorded on the temporary differences between the accounting and income tax basis of assets and liabilities, using the enacted tax rates expected to apply when the temporary differences are expected to reverse. Deferred tax assets are reviewed each period and a valuation allowance is provided if, after considering available evidence, it is more likely than not that a deferred tax asset will not be realized. Enerplus considers both positive and negative evidence including historic and expected future taxable income, reversing existing temporary differences and tax basis carry forward periods in making this assessment. A valuation allowance is removed in any period where available evidence indicates all or a portion of the valuation allowance is no longer required. The financial statement effect of an uncertain tax position is recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxation authority. Penalties and interest related to income tax are recognized in income tax expense.

j) Financial Instruments

i. Fair Value Measurements

Financial instruments are initially recorded at fair value, defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. For financial instruments carried at fair value, inputs used in determining the fair value are characterized according to the following fair value hierarchy:

- Level 1 – Inputs represent quoted market prices in active markets for identical assets or liabilities.
- Level 2 – Inputs other than quoted market prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted market prices for similar assets or liabilities in active markets or other market corroborated inputs.
- Level 3 – Inputs that are not observable from objective sources, such as forward prices supported by little or no market activity or internally developed estimates of future cash flows used in a present value model.

Subsequent measurement is based on classification of the financial instrument into one of the following five categories: held-for-trading, held-to-maturity, available-for-sale, loans and receivables or other financial liabilities.

ii. Non-derivative financial instruments

From time-to-time, Enerplus may hold certain marketable securities in entities involved in the oil and gas industry which would be included in other assets on the Consolidated Balance Sheets. These investments may include both publicly traded and unlisted marketable securities. Publicly traded investments are classified as available-for-sale and carried at fair value based on a Level 1 designation, with changes in fair value recorded in other comprehensive income. Fair values are determined by reference to quoted market bid prices at the close of business on the balance sheet date. When investments are ultimately sold any gains or losses are recognized in net income and any unrealized gains or losses previously recognized in other comprehensive income are reversed.

The carrying amount of cash, restricted cash, accounts receivable, accounts payable, dividends payable and bank credit facilities reported on the Consolidated Balance Sheets approximates fair value. The fair value of long-term debt has been disclosed in Note 15.

Enerplus capitalizes debt issuance costs, except for those related to revolving credit facilities. These costs are presented on the Consolidated Balance Sheets as a direct deduction from the carrying amount of the related debt liability.

iii. Derivative financial instruments

Enerplus enters into financial derivative contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Enerplus has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, all financial derivative contracts are classified as held-for-trading and are recorded at fair value based on a Level 2 designation, with changes in fair value recorded in net income. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date. Enerplus' accounting policy is to not offset the fair values of its financial derivative assets and liabilities.

Enerplus' crude oil, natural gas and natural gas liquids physical delivery purchase and sales contracts qualify as normal purchases and sales as they are entered into and held for the purpose of receipt or delivery of products in accordance with the Company's expected purchase, sale or usage requirements. As such, these contracts are not considered derivative financial instruments. Settlements on these physical contracts are recognized in net income over the term of the contracts as they occur.

k) Foreign Currency

i. Foreign currency transactions

Transactions denominated in foreign currencies are translated to Canadian dollars using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Foreign currency differences arising on translation are recognized in net income in the period in which they arise.

ii. Foreign operations

Assets and liabilities of Enerplus' U.S. operations are translated into Canadian dollars at period end exchange rates while revenues and expenses are translated using average rates for the period. Gains and losses from the translation are deferred and included in the cumulative translation adjustment which is recorded in accumulated other comprehensive income.

l) Share-Based Compensation

Enerplus' share-based compensation plans include its cash-settled Restricted Share Unit ("RSU"), Performance Share Unit ("PSU") and Director Share Unit ("DSU") plans, its equity-settled RSU and PSU plans, as well as Enerplus' Stock Option Plan. The final cash-settled RSU grant was paid in 2016. The Company is authorized to issue up to 5% of outstanding common shares from treasury in relation to its equity-settled RSU and PSU plans. In 2014, the Company suspended the issuance of stock options.

i. RSU, PSU, and DSU plans

Under Enerplus' RSU plan, employees receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and vests one-third each year for three years. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period.

Under Enerplus' PSU plan, executives and management receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and they vest at the end of three years. The value upon vesting is based on value of the underlying shares plus notional accrued dividends along with a multiplier that ranges from 0 to 2 depending on Enerplus' performance compared to the TSX oil and gas index over the vesting period.

Under Enerplus' DSU plan, directors receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded is based on the annual retainer value and they vest upon the director leaving the Board. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period. All DSU grants are settled in cash.

Enerplus recognizes a liability in respect of its cash-settled long-term incentive plans based on their estimated fair value. The liability is re-measured at each reporting date and at settlement date with any changes in the fair value recorded as share-based compensation, included in general and administrative expense.

Enerplus recognizes non-cash share-based compensation expense over the vesting period of the equity-settled long-term incentive plans, based on the estimated grant date fair value of the respective awards. Share-based compensation charges are recorded on the Consolidated Statements of Income/(Loss) with an offset to paid-in capital. Each period, management performs an estimate of the PSU plan multiplier. Any differences that arise between the actual multiplier on plan settlement and management's estimate is recorded to share-based compensation. On settlement of these plans, amounts previously recorded to paid-in capital are reclassified to share capital.

ii. Stock options

Under Enerplus' Stock Option Plan, employees were granted options to purchase common shares of the Company at an exercise price equal to the market value of the common shares on the date the options are granted. Options granted were exercisable in thirds over the three year vesting schedule and expire seven years after the date the options are granted. Enerplus used the Black-Scholes option pricing model to calculate the grant date fair value of stock options granted under the Company's Stock Option Plan. This amount was charged to earnings as share-based compensation over the vesting period of the options, with a corresponding increase in paid-in capital. When options are exercised, the proceeds, together with the amount recorded in paid-in capital, are recorded to share capital.

m) Net Income Per Share

Basic net income per common share is computed by dividing net income by the weighted average number of common shares outstanding during the period.

For the diluted net income per common share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income. The weighted average number of diluted shares is calculated in accordance with the treasury stock method which assumes that the proceeds received from the exercise of all stock options would be used to repurchase common shares at the average market price.

n) Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation, environmental and other sources are recognized when it is probable that a liability has been incurred and the amount can be reasonably estimated. Contingencies are adjusted as additional information becomes available or circumstances change.

o) Accounting Changes and Recent Pronouncements Issued

i. Recently adopted accounting standards

Effective in 2016, Enerplus adopted the following Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"):

- ASU 2014-12, *Compensation – Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period*
- ASU 2015-02*, Amendments to the Consolidation Analysis*
- ASU 2015-03*, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*

The adoption of these ASUs did not have a material impact on Enerplus' Consolidated Financial Statements.

In January 2017, the FASB issued ASU 2017-01, *Business Combinations (Topic 805): Clarifying the definition of a business.* The amendments in the ASU provide a screen to determine whether an integrated set of assets and activities (a "set") is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired is concentrated in a single or group of similar identifiable assets, that the set is not a business. The ASU is effective January 1, 2018 and is to be applied prospectively, with early adoption permitted. Enerplus has early adopted this ASU for the year ended December 31, 2016. As a result of the early adoption of this ASU, certain Canadian properties that were acquired during the year were accounted for as a property acquisition instead of a business combination.

ii. Future accounting changes

Enerplus will adopt the following ASU's issued by the FASB, which have been issued but are not yet effective.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers,* which will require entities to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard also will require expanded disclosures regarding the nature, amount, timing and certainty of revenue and cash flows from contracts with customers.

The FASB further issued several ASUs in 2016 which provide clarification on implementation of the amended standard, *Revenue from Contracts with Customers* (Topic 606), and included technical corrections and improvements and practical expedients that can be applied under certain circumstances. The amendments under these ASUs will become effective on January 1, 2018, however early adoption is permitted in 2017. Enerplus does not intend to early adopt these amendments, and continues to assess the impact they will have on the Consolidated Financial Statements.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842).* The ASU introduces a lessee accounting model that requires that most leases be recorded as a lease asset and lease liability on the balance sheet, with some exceptions. The ASU provides additional guidance on identifying and separating components of leases and a practical expedient on making this determination. The ASU is effective January 1, 2019, with early adoption permitted. Enerplus does not intend to early adopt these amendments, and continues to assess the impact they will have on the Consolidated Financial Statements.

In November 2016, the FASB issued ASU 2016-18, *Statements of Cash Flows – Restricted Cash*. The ASU requires amounts described as restricted cash and restricted cash equivalents to be included with cash and cash equivalents when reconciling the total beginning and ending amounts for the periods shown on the Consolidated Statements of Cash Flows. The updated guidance is effective January 1, 2018, with early adoption permitted. The adoption of this update is not expected to have a material impact on the Consolidated Financial Statements.

In January 2017, the FASB issued ASU 2017-04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment*. This standard eliminates Step 2 of the goodwill impairment test, and requires a goodwill impairment charge for the amount that the goodwill carrying amount exceeds the reporting unit's fair value. The updated guidance is effective for January 1, 2020, with early adoption permitted. Enerplus does not expect to early adopt these amendments, and continues to assess the impact they will have on the Consolidated Financial Statements.

3) ACCOUNTS RECEIVABLE

($ thousands)	December 31, 2016	December 31, 2015
Accrued receivables	$ 83,774	$ 91,378
Accounts receivable - trade	33,305	22,615
Current income tax receivable	1,564	21,410
Allowance for doubtful accounts	(3,275)	(3,247)
Total accounts receivable, net of allowance for doubtful accounts	$ 115,368	$ 132,156

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

As at December 31, 2016 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 13,567,390	$ (12,840,938)	$ 726,452
Other capital assets	106,070	(94,092)	11,978
Total PP&E	$ 13,673,460	$ (12,935,030)	$ 738,430

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

Acquisitions:

For the years ended December 31, 2016 and 2015, Enerplus acquired property and land totaling $126.1 million, and $9.6 million, respectively. For the year ended December 31, 2016, the acquisition of property and land consisted mainly of Enerplus' acquisition of assets in Ante Creek in NW Alberta for $110.3 million.

Divestments:

For the years ended December 31, 2016 and 2015, Enerplus disposed of properties for proceeds of $670.4 million and $286.6 million, respectively. Certain asset divestments in 2016 resulted in gains, as the divestments caused a significant alteration in the relationship between the cost centre's capitalized costs and proved reserves. During 2016, Enerplus recognized gains on asset divestments of $559.2 million. Enerplus did not recognize any gains on asset divestments in 2015.

5) IMPAIRMENT

a) Impairment of PP&E

($ thousands)	2016	2015	2014
Oil and natural gas properties:			
Canada cost centre	$ 89,359	$ 286,700	$ —
U.S. cost centre	211,812	1,065,728	—
Total impairment expense	$ 301,171	$ 1,352,428	$ —

The impairments for the period ended December 31, 2016 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 test as at December 31, 2016, 2015 and 2014:

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
2016	$ 42.75	1.32	$ 52.26	$ 2.49	$ 2.17
2015	50.28	1.27	59.38	2.58	2.69
2014	94.99	1.09	94.84	4.30	4.60

b) Goodwill Impairment

Goodwill impairment testing is performed annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus' annual goodwill impairment assessment as at December 31, 2016 and December 31, 2015 indicated no impairment.

6) ACCOUNTS PAYABLE

($ thousands)	December 31, 2016	December 31, 2015
Accrued payables	$ 104,816	$ 167,253
Accounts payable - trade	79,718	72,697
Total accounts payable	$ 184,534	$ 239,950

7) DEBT

($ thousands)	December 31, 2016	December 31, 2015
Current:		
Senior notes	$ 29,539	$ —
	29,539	—
Long-term:		
Bank credit facility	$ 23,226	$ 86,543
Senior notes	716,060	1,137,139
	739,286	1,223,682
Total debt	$ 768,825	$ 1,223,682

Bank Credit Facility

Enerplus has a senior unsecured, covenant-based, $800 million bank credit facility that matures on October 31, 2019. Drawn fees range between 150 and 315 basis points over bankers' acceptance rates, with current drawn fees of 170 basis points. Standby fees on the undrawn portion of the facility are based on 20% of the drawn pricing. The Company has the ability to request an extension of the facility or repay the entire balance at the end of the term. At December 31, 2016 Enerplus had $23.2 million (December 31, 2015 - $86.5 million) drawn and was in compliance with all covenants under the facility. During 2016 a fee of $0.7 million (2015 - $0.3 million, 2014 - $0.6 million) was paid to extend the facility. The weighted average interest rate on the facility for the year ended December 31, 2016 was 2.6% (December 31, 2015 – 2.2%).

Senior Notes

During 2016 Enerplus repurchased US$267 million in outstanding senior notes at a discount, resulting in gains of $19.3 million. These repurchases resulted in total repayments of $335.4 million in 2016.

On June 18, 2015 Enerplus made bullet payments on both its US$40 million and $40 million senior notes, which were issued on June 18, 2009. On October 1, 2015 Enerplus made its fifth and final principal repayment of US$10.8 million on the US$54 million senior notes issued on October 1, 2003 and settled the corresponding foreign exchange swap. The final principal repayment totaled $11.0 million and a gain of $3.3 million was realized on the foreign exchange swap, which was recorded as a realized foreign exchange gain on the Consolidated Statements of Income/(Loss).

The terms and rates of the Company's outstanding senior notes are detailed below:

Issue Date	Interest Payment Dates	Principal Repayment	Coupon Rate	Original Principal ($ thousands)	Remaining Principal ($ thousands)	CDN$ Carrying Value ($ thousands)
September 3, 2014	March 3 and Sept 3	5 equal annual installments beginning September 3, 2022	3.79%	US$200,000	US$105,000	$ 140,923
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2019	4.34%	CDN$30,000	CDN$30,000	30,000
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	26,854
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	400,125
June 18, 2009	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017	7.97%	US$225,000	US$110,000	147,697
					Total carrying value	$ 745,599
					Current portion	29,539
					Long-term portion	$ 716,060

At December 31, 2016 Enerplus was in full compliance with all covenants under the senior notes.

8) ASSET RETIREMENT OBLIGATION

At December 31, 2016 Enerplus estimated the present value of its asset retirement obligation to be $181.7 million (December 31, 2015 - $206.4 million) based on a total undiscounted liability of $452.1 million (December 31, 2015 - $556.4 million). The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.86% at December 31, 2016 (December 31, 2015 – 5.91%). The majority of Enerplus' asset retirement obligation expenditures are expected to be incurred between 2025 and 2055.

($ thousands)	December 31, 2016	December 31, 2015
Balance, beginning of year	$ 206,359	$ 288,692
Change in estimates	5,496	(35,386)
Property acquisition and development activity	3,003	761
Divestments	(35,635)	(48,748)
Settlements	(8,390)	(14,935)
Accretion expense	10,867	15,975
Balance, end of year	$ 181,700	$ 206,359

9) OIL AND NATURAL GAS SALES

($ thousands)	2016	2015	2014
Oil and natural gas sales	$ 882,126	$ 1,052,382	$ 1,849,312
Royalties(1)	(159,394)	(167,990)	(323,118)
Oil and natural gas sales, net of royalties	$ 722,732	$ 884,392	$ 1,526,194

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

10) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	2016	2015	2014
General and administrative expense	$ 59,773	$ 81,312	$ 83,493
Share-based compensation expense	26,546	22,558	21,548
General and administrative expense	$ 86,319	$ 103,870	$ 105,041

11) INTEREST EXPENSE

($ thousands)	2016	2015	2014
Realized:			
Interest on bank debt and senior notes	$ 45,443	$ 66,456	$ 62,240
Unrealized:			
Cross currency interest rate swap (gain)/loss	—	—	580
Interest expense	$ 45,443	$ 66,456	$ 62,820

12) FOREIGN EXCHANGE

($ thousands)	2016	2015	2014
Realized:			
Foreign exchange (gain)/loss	$ 108	$ (8,705)	$ 11,165
Unrealized:			
Translation of U.S. dollar debt and working capital (gain)/loss	(40,634)	160,791	68,202
Cross currency interest rate swap (gain)/loss	—	—	(16,128)
Foreign exchange swap (gain)/loss	—	21,847	(6,149)
Foreign exchange (gain)/loss	$ (40,526)	$ 173,933	$ 57,090

13) INCOME TAXES

Enerplus' provision for income tax is as follows:

($ thousands)	2016	2015	2014
Current tax expense/(recovery)			
Canada	$ (661)	$ (795)	$ (543)
United States	(1,690)	(16,092)	5,541
Current tax expense/(recovery)	(2,351)	(16,887)	4,998
Deferred Tax expense/(recovery)			
Canada	$ (23,714)	$ (52,603)	$ 64,746
United States	(211,133)	(97,985)	68,084
Deferred tax expense/(recovery)	(234,847)	(150,588)	132,830
Income tax expense/(recovery)	$ (237,198)	$ (167,475)	$ 137,828

The following provides a reconciliation of income taxes calculated at the Canadian statutory rate to the actual income taxes:

($ thousands)	2016	2015	2014
Income/(loss) before taxes			
Canada	$ 121,257	$ (500,113)	$ 247,856
United States	38,961	(1,190,765)	189,048
Total income/(loss) before taxes	160,218	(1,690,878)	436,904
Canadian statutory rate	27.00%	27.00%	25.35%
Expected income tax expense/(recovery)	$ 43,259	$ (456,537)	$ 110,755
Impact on taxes resulting from:			
Change in valuation allowance	$ (266,896)	$ 443,655	$ 8,007
Foreign and statutory rate differences	(12,826)	(179,809)	11,204
Non-taxable capital (gains)/losses	(6,478)	23,450	8,318
Share-based compensation	6,611	4,395	2,636
Other	(868)	(2,629)	(3,092)
Income tax expense/(recovery)	$ (237,198)	$ (167,475)	$ 137,828

During 2015 the Alberta Provincial tax rate change resulted in an increase in the Canadian statutory rate by 1.65% for the year.

Deferred income tax asset (liability) consists of the following temporary differences:

As at December 31 ($ thousands)	2016	2015
Deferred income tax liabilities		
Derivative financial assets and credits	$ —	$ (17,319)
Total deferred income tax liabilities	—	(17,319)
Deferred income tax assets		
Property, plant and equipment	$ 257,105	$ 382,454
Tax loss carry-forwards and other credits	736,395	672,193
Asset retirement obligation	50,462	57,364
Derivative financial assets and credits	10,515	—
Other assets	26,753	36,156
Total deferred income tax assets	1,081,230	1,148,167
Less valuation allowance	(347,867)	(614,763)
Total deferred income tax assets, net	733,363	533,404
Net deferred income tax asset	$ 733,363	$ 516,085

In the current period, Enerplus reported a deferred income tax asset of $733.4 million (2015 - $516.1 million). We have a valuation allowance of $347.9 million at December 31, 2016 (2015 - $614.8 million).

Loss carry-forwards and tax credits available for tax reporting purposes:

As at December 31 ($ thousands)	**2016**	**Expiration Date**
Canada		
Capital losses	$ 1,224,000	Indefinite
Non-capital losses	377,000	2028-2036
United States		
Net operating losses	$ 894,000	2030-2036
Alternative minimum tax credits	112,000	Indefinite

Changes in the balance of Enerplus' unrecognized tax benefits are as follows:

($ thousands)	**2016**	**2015**	**2014**
Balance, beginning of year	$ 15,100	$ 17,000	$ 18,000
Increase/(decrease) for tax positions of prior years	—	(300)	2,700
Settlements	(1,800)	(1,600)	(3,700)
Balance, end of year	$ 13,300	$ 15,100	$ 17,000

If recognized, all of Enerplus' unrecognized tax benefits as at December 31, 2016 would affect Enerplus' effective income tax rate. It is not anticipated that the amount of unrecognized tax benefits will significantly change during the next 12 months.

A summary of the taxation years, by jurisdiction, that remain subject to examination by the taxation authorities are as follows:

Jurisdiction	**Taxation Years**
Canada - Federal & Provincial	2006-2016
United States - Federal & State	2008-2016

Enerplus and its subsidiaries file income tax returns primarily in Canada and the United States. Matters in dispute with the taxation authorities are ongoing and in various stages of completion.

14) SHAREHOLDERS' EQUITY

a) Share Capital

	2016		**2015**		**2014**	
Authorized unlimited number of common shares Issued: (thousands)	**Shares**	**Amount**	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	206,539	$ 3,133,524	205,732	$ 3,120,002	202,758	$ 3,061,839
Issued for cash:						
Public offering	33,350	230,115	—	—	—	—
Share issue costs (net of tax of $2,621)	—	(7,084)	—	—	—	—
Stock Option Plan	—	—	234	3,205	1,944	31,350
Non-cash:						
Share-based compensation - settled	594	9,407	573	10,050	—	—
Stock Option Plan - exercised	—	—	—	267	—	4,978
Stock Dividend Plan(1)	—	—	—	—	1,030	21,835
Balance, end of year	240,483	$ 3,365,962	206,539	$ 3,133,524	205,732	$ 3,120,002

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

The Company is authorized to issue an unlimited number of common shares without par value.

On May 31, 2016, Enerplus issued 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230,115,000 ($220,410,400, net of issue costs before tax).

At the Company's Annual General Meeting on May 6, 2016, the Shareholders of the Company approved a reduction in Enerplus' legal stated capital to $1 per share to be reflected in the contributed surplus account of the Company. This transaction does not result in an adjustment to the financial statements under U.S. GAAP.

b) Dividends

($ thousands)	2016	2015	2014
Cash dividends	$ 35,439	$ 131,955	$ 199,263
Stock dividends[1]	—	—	21,835
Dividends to shareholders	$ 35,439	$ 131,955	$ 221,098

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

For the year ended December 31, 2016 Enerplus paid dividends of $0.16 per weighted average common share totaling $35.4 million (December 31, 2015 - $0.64 per share and $132.0 million, December 31, 2014 - $1.08 per share and $221.1 million).

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)	2016	2015	2014
Cash:			
Long-term incentive plans (recovery)/expense	$ 3,114	$ 874	$ (1,220)
Non-Cash:			
Long-term incentive plans expense	26,951	18,878	9,349
Stock option plan expense	63	709	4,137
Equity swap (gain)/loss	(3,582)	2,097	9,282
Share-based compensation expense	$ 26,546	$ 22,558	$ 21,548

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. The final cash-settled RSU grant was paid in 2016.

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

For the year ended December 31, 2016	**Cash-settled LTI Plans**		**Equity-settled LTI Plans**		
(thousands of units)	**RSU**	**DSU**	**PSU**	**RSU**	**Total**
Balance, beginning of year	92	166	1,222	1,627	3,107
Granted	—	140	1,433	2,007	3,580
Vested	(89)	—	—	(594)	(683)
Forfeited	(3)	—	(590)	(342)	(935)
Balance, end of year	—	306	2,065	2,698	5,069

Cash-settled LTI Plans

For the year ended December 31, 2016 the Company recorded cash share-based compensation expense of $3.1 million (2015 - $0.9 million, 2014 - recovery of $1.2 million). For the year ended December 31, 2016, the Company made cash payments of $2.7 million related to its cash-settled plans (2015 - $15.0 million, 2014 - $14.1 million).

As of December 31, 2016, a liability of $3.9 million (December 31, 2015 - $2.3 million) with respect to the DSU plan has been recorded to Accounts Payable on the Consolidated Balance Sheets.

Equity-settled LTI Plans

For the year ended December 31, 2016 the Company recorded non-cash share-based compensation expense of $27.0 million (2015 - $18.9 million, 2014 - $9.3 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 December 31, 2016 ($ thousands, except for years)	PSU(1)	RSU	Total
Cumulative recognized share-based compensation expense	$ 22,739	$ 15,290	$ 38,029
Unrecognized share-based compensation expense	13,220	5,330	18,550
Fair value	$ 35,959	$ 20,620	$ 56,579
Weighted-average remaining contractual term (years)	1.6	1.3	

(1) Includes estimated performance multipliers.

ii) Stock Option Plan

The Company used the Black-Scholes option pricing model to estimate the fair value of options granted under the Stock Option Plan. The Company suspended the issuance of stock options in 2014.

The following table summarizes the stock option plan activity for the year ended December 31, 2016:

Year ended December 31, 2016	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding, beginning of year	7,580	$ 18.49
Forfeited	(1,680)	19.33
Options outstanding and exercisable, end of year	5,900	$ 18.29

At December 31, 2016, 5,900,000 options were exercisable at a weighted average exercise price of $18.29 with a final expiry in 2020, giving an aggregate intrinsic value of nil (December 31, 2015 - nil, December 31, 2014 - nil). The intrinsic value of options exercised during the year ended December 31, 2016 was nil (December 31, 2015 - $0.2 million, December 31, 2014 - $13.4 million).

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

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

(thousands, except per share amounts)	2016	2015	2014
Net income/(loss)	$ 397,416	$ (1,523,403)	$ 299,076
Weighted average shares outstanding - Basic	226,530	206,205	204,510
Dilutive impact of share-based compensation(1)	4,763	—	2,914
Weighted average shares outstanding - Diluted	231,293	206,205	207,424
Net income/(loss) per share			
Basic	$ 1.75	$ (7.39)	$ 1.46
Diluted	$ 1.72	$ (7.39)	$ 1.44

(1) For the year ended December 31, 2015, the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At December 31, 2016, the carrying value of cash, restricted 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 December 31, 2016 senior notes included in long-term debt had a carrying value of $716.0 million and a fair value of $771.0 million (December 31, 2015 - $1,137.2 million and $1,220.8 million, respectively).

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

b) Derivative Financial Instruments

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

The following tables summarize the change in fair value for the respective years:

Gain/(Loss) ($ thousands)	December 31, 2016	December 31, 2015	December 31, 2014	Income Statement Presentation
Equity Swaps	$ 3,582	$ (2,097)	$ (9,282)	General and administrative expense
Electricity Swaps	1,135	(408)	(1,275)	Operating expense
Cross Currency Interest Rate Swap:				
Interest	—	—	(580)	Interest expense
Foreign Exchange	—	—	16,128	Foreign exchange
Foreign Exchange Derivatives	—	(21,847)	6,149	Foreign exchange
Commodity Derivative Instruments:				
Oil	(96,238)	(99,790)	182,019	Commodity derivative instruments
Gas	(13,505)	(45,194)	48,879	
Total Unrealized Gain/(Loss)	$ (105,026)	$ (169,336)	$ 242,038	

The following table summarizes the effect of Enerplus' commodity derivative instruments on the Consolidated Statements of Income/(Loss):

($ thousands)	2016	2015	2014
Change in fair value gain/(loss)	$ (109,743)	$ (144,984)	$ 230,898
Net realized cash gain/(loss)	80,346	287,708	3,475
Commodity derivative instruments gain/(loss)	$ (29,397)	$ 142,724	$ 234,373

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

	December 31, 2016		December 31, 2015		
	Liabilities		Assets	Liabilities	
($ thousands)	Current	Long-term	Current	Current	Long-term
Electricity Swaps	$ 641	$ —	$ —	$ 1,776	$ —
Equity Swaps	1,044	891	—	2,324	3,193
Commodity Derivative Instruments:					
Oil	17,466	11,375	67,397	—	—
Gas	9,464	—	4,041	—	—
Total	$ 28,615	$ 12,266	$ 71,438	$ 4,100	$ 3,193

c) Risk Management

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

i) Market Risk

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

Commodity Price Risk:

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

The following tables summarize Enerplus' price risk management positions at February 23, 2017:

Crude Oil Instruments:

Instrument Type(1)	bbls/day	US$/bbl(1)
Jan 1, 2017 – Jun 30, 2017		
WTI Swap	2,000	53.50
WTI Purchased Put	14,000	50.29
WTI Sold Call	14,000	61.14
WTI Sold Put	14,000	38.94
WCS Differential Swap	2,000	(14.75)
Jul 1, 2017 – Dec 31, 2017		
WTI Swap	2,000	53.50
WTI Purchased Put	18,000	50.61
WTI Sold Call	18,000	60.33
WTI Sold Put	18,000	39.62
WCS Differential Swap	2,000	(14.75)
Jan 1, 2018 – Dec 31, 2018		
WTI Swap	3,000	53.73
WTI Purchased Put	9,500	54.00
WTI Sold Call	9,500	63.09
WTI Sold Put	9,500	43.13
Jan 1, 2019 – Mar 31, 2019		
WTI Swap	3,000	53.73
WTI Purchased Put	1,000	56.00
WTI Sold Call	1,000	70.00
WTI Sold Put	1,000	45.00
Apr 1, 2019 – Dec 31, 2019		
WTI Purchased Put	4,000	54.69
WTI Sold Call	4,000	66.18
WTI Sold Put	4,000	43.75

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

Natural Gas Instruments:

Instrument Type[1]	MMcf/day	US$/Mcf
Jan 1, 2017 – Dec 31, 2017		
NYMEX Purchased Put	50.0	2.75
NYMEX Sold Call	50.0	3.41
NYMEX Sold Put	50.0	2.06

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

Electricity Instruments:

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

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

Physical Contracts:

Instrument Type	MMcf/day	US$/Mcf
Purchases:		
Jan 1, 2017 – Oct 31, 2017		
AECO-NYMEX Basis	45.0	(0.92)
Nov 1, 2017 – Oct 31, 2018		
AECO-NYMEX Basis	45.0	(0.78)
Nov 1, 2018 – Oct 31, 2019		
AECO-NYMEX Basis	45.0	(0.72)
Sales:		
Jan 1, 2017 – 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 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 the currency risk relating to its senior notes through the derivative instruments detailed below.

Foreign Exchange Derivatives:

During 2014, Enerplus entered into foreign exchange collars to hedge a portion of its foreign exchange exposure on U.S. dollar denominated oil and gas sales. In 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 rate of 1.20 to partially mitigate losses on the foreign exchange collars entered into in 2014. The foreign exchange collars and forward rate swaps matured in December 2015, and during 2015 Enerplus recognized $39.2 million in net realized foreign exchange losses (2014 – gain of $0.7 million).

During 2007 Enerplus entered into foreign exchange swaps on US$54.0 million of notional debt at an average US/CDN exchange rate of 1.02. The remaining $10.8 million notional amount under the swap was settled in October 2015 in conjunction with the final principal repayment on the US$54.0 million senior notes, resulting in a realized foreign exchange gain of $3.3 million.

During 2011 Enerplus entered into foreign exchange swaps on US$175.0 million of notional debt at approximately par. These foreign exchange swaps matured between June 2017 and June 2021 in conjunction with the principal repayments on the US$225.0 million senior notes. During 2015 Enerplus unwound these swaps and recognized a gain of $39.9 million.

Interest Rate Risk:

At December 31, 2016, approximately 97% of Enerplus' debt was based on fixed interest rates and 3% was based on floating interest rates. At December 31, 2016 Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 14. Enerplus has entered into various equity swaps maturing between 2017 and 2018 and has effectively fixed the future settlement cost on 470,000 shares at a weighted average price of $16.89 per share.

ii) Credit Risk

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

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

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At December 31, 2016 approximately 58% of Enerplus' marketing receivables were with companies considered investment grade.

At December 31, 2016 approximately $1.9 million or 2% of Enerplus' total accounts receivable were aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at December 31, 2016 was $3.3 million (December 31, 2015 - $3.2 million).

iii) Liquidity Risk & Capital Management

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

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

16) COMMITMENTS, CONTINGENCIES AND GUARANTEES

a) Commitments

Enerplus has the following minimum annual commitments at December 31, 2016:

		Minimum Annual Commitment Each Year					
($ thousands)	Total	2017	2018	2019	2020	2021	Thereafter
Bank credit facility[1]	$ 23,226	$ —	$ —	$ 23,226	$ —	$ —	$ —
Senior notes[1]	745,599	29,539	29,539	59,539	109,564	109,564	407,854
Transportation commitments	293,624	31,891	29,104	24,618	22,800	19,523	165,688
Processing commitments	42,931	11,427	10,136	10,136	1,550	1,550	8,132
Drilling and completions	29,137	29,137	—	—	—	—	—
Office lease commitments	88,345	12,197	12,006	10,494	10,816	10,848	31,984
Sublease recoveries	(9,293)	(1,956)	(1,613)	(1,709)	(1,759)	(1,516)	(740)
Net office lease commitments	79,052	10,241	10,393	8,785	9,057	9,332	31,244
Total commitments[2][3]	$ 1,213,569	$ 112,235	$ 79,172	$ 126,304	$ 142,971	$ 139,969	$ 612,918

(1) Interest payments have not been included.
(2) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(3) US$ commitments have been converted to CDN$ using the December 31, 2016 foreign exchange rate of 1.3427.

b) 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.

c) Guarantees

(i) Corporate indemnities have been provided by Enerplus to all directors and officers for various items including costs to settle suits or actions due to their association with Enerplus. Enerplus has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. Each indemnity, subject to certain exceptions, applies for so long as the indemnified person is a director or officer of Enerplus.

(ii) Enerplus may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents Enerplus from making a reasonable estimate of the maximum potential amounts that may be required to be paid.

17) GEOGRAPHICAL INFORMATION

As at and for the year ended December 31, 2016 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 233,391	$ 489,341	$ 722,732
Operating expenses	134,593	113,324	247,917
Depletion, depreciation and accretion	126,062	202,902	328,964
Property, plant and equipment	304,048	434,382	738,430
Deferred income tax asset	183,691	549,672	733,363
Goodwill	451,121	200,542	651,663

As at and for the year ended December 31, 2015 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 369,559	$ 514,833	$ 884,392
Operating expenses	217,077	123,406	340,483
Depletion, depreciation and accretion	198,641	309,538	508,179
Property, plant and equipment	435,604	750,669	1,186,273
Deferred income tax asset	157,356	358,729	516,085
Goodwill	451,121	206,710	657,831

As at and for the year ended December 31, 2014 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 689,135	$ 837,059	$ 1,526,194
Operating expenses	254,135	94,461	348,596
Depletion, depreciation and accretion	236,027	331,615	567,642
Property, plant and equipment	1,028,436	1,624,629	2,653,065
Deferred income tax asset	104,752	192,560	297,312
Goodwill	451,121	173,269	624,390

18) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	December 31, 2016	December 31, 2015	December 31, 2014
Accounts receivable	$ 16,982	$ 37,064	$ (8,392)
Other current assets	2,154	(2,634)	(6,777)
Accounts payable	(4,061)	(47,260)	(37,245)
	$ 15,075	$ (12,830)	$ (52,414)

b) Other

($ thousands)	December 31, 2016	December 31, 2015	December 31, 2014
Income taxes paid/(received)	$ (21,244)	$ (22,274)	$ 18,087
Interest paid	$ 48,545	$ 65,498	$ 58,416

5 YEAR DETAILED STATISTICAL REVIEW

	2016	2015	2014	2013	2012
Daily Production(1)					
Crude oil (bbls/day)	38,353	41,639	40,208	38,250	36,509
NGLs (bbls/day)	4,903	4,763	3,565	3,472	3,627
Natural gas (Mcf/day)	299,214	360,733	356,142	288,423	251,773
BOE per day	93,125	106,524	103,130	89,793	82,098
Drilling Activity (net wells)	25	46	88	62	75
Average Benchmark Pricing					
WTI crude oil (US$ per bbl)	$ 43.32	$ 48.80	$ 93.00	$ 97.97	$ 94.21
AECO natural gas – monthly (per Mcf)	2.09	2.77	4.42	3.16	2.40
NYMEX natural gas – last day(US$ per Mcf)	2.46	2.66	4.41	3.65	2.79
US/CDN exchange rate (average)	1.32	1.28	1.10	1.03	1.00
Realized Pricing					
Crude oil(2) (per bbl)	$ 44.84	$ 48.43	$ 86.28	$ 85.05	$ 78.79
Natural gas liquids(2) (per bbl)	15.29	18.06	51.72	53.20	53.66
Natural gas(2) (per Mcf)	2.06	2.15	3.94	3.42	2.59

($ thousands, except per share amounts)	2016	2015	2014	2013	2012
Financial					
Oil and natural gas sales(2)	$ 882,126	$ 1,052,381	$ 1,849,312	$ 1,616,795	$ 1,365,542
Adjusted funds flow	305,605	493,101	859,020	754,233	644,523
Cash flow from operating activities	312,290	465,336	787,197	766,478	535,689
Cash and stock dividends to Shareholders	35,439	131,955	221,098	216,864	301,560
Per share	0.16	0.64	1.08	1.08	1.62
Capital spending	209,135	493,403	811,026	681,437	853,435
Property and land acquisitions	126,126	9,552	18,491	244,837	185,337
Property Divestitures	670,364	286,614	203,576	365,135	275,771
Total net capital expenditures(3)	(333,627)	220,813	632,883	567,607	774,862
Total assets	2,638,850	2,581,234	4,031,492	3,681,799	3,856,083
Total debt, net cash and restricted cash	375,520	1,216,184	1,134,894	1,022,308	1,064,365
Adjusted payout ratio(4)	80%	128%	118%	114%	174%
Net debt/ adjusted funds flow ratio	1.2x	2.5x	1.3x	1.4x	1.7x
Oil and Gas Economics					
Net royalty rate	22%	21%	23%	21%	20%
Average realized price(2)	$ 25.88	$ 27.07	$ 49.13	$ 49.32	$ 45.48
Transportation Costs	(3.14)	(2.95)	(2.69)	(1.77)	(1.16)
Royalties & Production Tax	(5.77)	(5.63)	(10.75)	(10.21)	(8.95)
Cash gains commodity derivative instruments	2.36	7.40	0.09	0.81	0.61
Average realized price, net	19.33	25.89	35.78	38.15	35.98
Cash operating expense	(7.31)	(8.75)	(9.23)	(9.94)	(10.27)
Operating netback, after hedging	12.02	17.14	26.55	28.21	25.71
Cash general and administrative expense	(1.84)	(2.11)	(2.19)	(3.25)	(2.79)
Cash interest, foreign exchange and other expenses	(1.28)	(2.78)	(1.42)	(1.71)	(1.42)
Current tax	0.07	0.43	(0.12)	(0.24)	(0.05)
Adjusted funds flow	$ 8.97	$ 12.68	$ 22.82	$ 23.01	$ 21.45

($ thousands, except per share amounts)	2016	2015	2014	2013	2012
Reserves[6]					
Proved Reserves					
Crude oil (Mbbls)	119,419	131,778	127,007	118,611	124,759
NGLs (Mbbls)	11,825	10,704	8,137	8,967	9,236
Conventional natural gas (MMcf)	95,769	183,564	331,709	409,830	413,906
Shale gas (MMcf)	726,614	625,081	564,583	411,431	146,127
MBOE	268,308	277,255	284,525	264,455	227,335
Probable Reserves					
Crude oil (Mbbls)	56,798	58,222	73,424	73,635	66,913
NGLs (Mbbls)	6,273	4,993	4,662	5,757	5,387
Conventional natural gas (MMcf)	30,521	53,802	124,721	183,744	198,727
Shale gas (MMcf)	276,169	338,288	275,357	189,430	78,373
MBOE	114,186	128,563	144,766	141,587	118,483
Proved Plus Probable Reserves					
Crude oil (Mbbls)	176,216	189,999	200,431	192,246	191,672
NGLs (Mbbls)	18,098	15,697	12,798	14,723	14,623
Conventional natural gas (MMcf)	126,290	237,366	456,430	593,574	612,634
Shale gas (MMcf)	1,002,783	963,368	839,940	600,861	224,500
MBOE	382,493	405,818	429,291	406,042	345,817
Reserves Life Index[7]					
Proved (years)	9.0	9.0	7.8	7.6	7.8
Proved plus probable (years)	12.3	12.2	10.7	10.8	10.9
Trading Information					
Canadian trading summary[9]					
High	$ 13.55	$ 16.09	$ 27.05	$ 19.96	$ 26.94
Low	$ 2.68	$ 4.24	$ 9.02	$ 12.26	$ 11.53
Close	$ 12.74	$ 4.75	$ 11.19	$ 19.30	$ 12.90
Volume	688,243	550,742	360,805	214,057	270,710
U.S. trading summary[10]					
High	$ 10.33	$ 13.16	$ 25.37	$ 18.79	$ 26.54
Low	$ 1.84	$ 3.01	$ 7.75	$ 12.03	$ 11.35
Close	$ 9.48	$ 3.42	$ 9.60	$ 18.18	$ 12.96
Volume	347,941	382,094	203,965	192,733	386,690
Weighted average number of shares outstanding (basic)	226,530	206,205	204,510	200,567	195,633
Number of shares outstanding at December 31	240,483	206,539	205,732	202,758	198,684

(1) Production is on a company interest basis
(2) Before transportation, royalties and the effects of commodity derivative instruments
(3) Includes office capital
(4) Calculated as the sum of cash dividends to shareholders, office capital and capital spending, divided by funds flow
(5) Net of commodity derivative instruments and transportation
(6) 2014, 2015 & 2016 reserves are based on gross reserves volumes. 2013 and earlier years are based on company interest reserves volumes. Company interest reserves consist of gross reserves (as defined in National Instrument 51-101) plus the Company's royalty interests. Company interest reserves are not a term defined in National Instrument 51-101 and may not be comparable to reserves disclosed by other issuers
(7) The Reserves Life Indices (RLI) are based upon year-end proved and proved plus probable reserves divided by the following year's proved and proved plus probable production volumes as forecast in the independent reserves engineering reports
(8) All shares are in thousands
(9) Canadian composite trading data including TSX thereafter. Volumes are in thousands
(10) U.S. composite trading data including NYSE thereafter. Volumes are in thousands

SUPPLEMENTAL INFORMATION

All reserves information, including our U.S. reserves, has been prepared in accordance with Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Independent reserves evaluations have been conducted on approximately 86% of the net present value (before tax, discounted at 10%, using forecast prices and costs) of our total proved plus probable reserves at December 31, 2016. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated approximately 48% of the net present value (before tax, discounted at 10%, using forecast prices and costs) of our Canadian total proved plus probable reserves and all of the reserves associated with properties located in North Dakota and Montana. McDaniel also reviewed the internal evaluation completed by Enerplus on the remaining 52% of the net present value (before tax, discounted at 10% using forecast prices and costs) of our Canadian properties. Netherland, Sewell & Associates, Inc. ("NSAI") evaluated all of our reserves of our U.S. properties in Pennsylvania.

The following reserves information sets out our gross reserves volumes at December 31, 2016 by product type and reserves category under McDaniel's January 1, 2017 forecast price scenarios. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit associated with a property. It should be noted that tables may not add due to rounding.

Forecast Price Assumptions

The estimated reserves volumes and the net present values of future net revenues ("NPV") at December 31, 2016 were based upon forecast crude oil and natural gas pricing assumptions prepared by McDaniel as of January 1, 2017. These prices were applied to the reserves evaluated by McDaniel and NSAI, along with those evaluated internally by Enerplus and reviewed by McDaniel. The base reference prices and exchange rates used by McDaniel are detailed below.

	CRUDE OIL				**NATURAL GAS**		**NATURAL GAS LIQUIDS**				
							Edmonton Par Price				
Year	**WTI**[(1)]	**Edmonton Light**[(2)]	**Alberta Heavy**[(3)]	**Sask Cromer Medium**[(4)]	**Alberta AECO Spot Prices**	**U.S. Henry Hub Gas Price**	**Propane**	**Butanes**	**Condensate & Natural Gasolines**	**Inflation Rate**	**Exchange Rate**
	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/MMbtu)	($US/MMbtu)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	(%/year)	($US/$Cdn)
2017	55.00	69.80	46.50	62.80	3.40	3.40	23.30	43.50	72.80	0.0	0.750
2018	58.70	72.70	50.50	67.60	3.15	3.20	23.70	47.90	75.80	2.0	0.775
2019	62.40	75.50	54.00	70.20	3.30	3.35	26.20	49.80	78.60	2.0	0.800
2020	69.00	81.10	58.00	75.40	3.60	3.65	28.30	56.40	84.30	2.0	0.825
2021	75.80	86.60	61.90	80.50	3.90	4.00	30.30	63.40	89.80	2.0	0.850
2022	77.30	88.30	63.10	82.10	3.95	4.05	30.90	64.70	91.60	2.0	0.850
2023	78.80	90.00	64.40	83.70	4.10	4.15	31.50	65.90	93.40	2.0	0.850
2024	80.40	91.80	65.60	85.40	4.25	4.25	32.20	67.30	95.20	2.0	0.850
2025	82.00	93.70	67.00	87.10	4.30	4.30	32.90	68.60	97.20	2.0	0.850
2026	83.70	95.60	68.40	88.90	4.40	4.40	33.60	70.00	99.20	2.0	0.850
2027	85.30	97.40	69.60	90.60	4.50	4.50	34.20	71.40	101.10	2.0	0.850
2028	87.00	99.40	71.10	92.40	4.60	4.60	34.90	72.80	103.10	2.0	0.850
2029	88.80	101.40	72.50	94.30	4.65	4.65	35.60	74.30	105.20	2.0	0.850
2030	90.60	103.50	74.00	96.30	4.75	4.75	36.30	75.80	107.40	2.0	0.850
2031	92.40	105.50	75.40	98.10	4.85	4.85	37.10	77.30	109.50	2.0	0.850
Thereafter	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	0.850

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40º API/0.5% sulphur.
(2) Edmonton Light Sweet 40º API/0.3% sulphur.
(3) Heavy Crude Oil 12º API at Hardisty, Alberta (after deducting blending costs to reach pipeline quality).
(4) Midale Cromer Crude Oil 29º API/2.0% sulphur.
(5) Escalation is approximately 2% per year thereafter.

Reserves Summary

Enerplus' 2P reserves decreased by 23.3 million BOE at year-end 2016 to 382.5 million BOE, down from 405.8 million BOE at year-end 2015. The Corporation replaced approximately 126% of its 2016 gross production through its exploration and development program, adding 42.6 million BOE of proved plus probable reserves, including revisions. Approximately 42% of the additions, including revisions, were crude oil and NGLs, representing the replacement of 113% of the Corporation's 2016 crude oil and NGLs production. The largest amount of crude oil reserves additions, including revisions, was in the Fort Berthold crude oil property in North Dakota. The largest amount of conventional natural gas and shale gas reserves additions, including revisions, was in the Marcellus shale gas property. A total of 37.3 million BOE of proved plus probable reserves were sold in 2016. Total proved plus probable conventional natural gas reserves, excluding shale gas, decreased by approximately 47% from year-end 2015. Total proved plus probable conventional natural gas and shale gas reserves decreased by approximately 6% from year-end 2015.

Reserves Summary[1]	**Light & Medium Oil (Mbbls)**	**Heavy Oil (Mbbls)**	**Tight Oil (Mbbls)**	**Total Oil (Mbbls)**	**Natural Gas Liquids (Mbbls)**	**Conventional Natural Gas (MMcf)**	**Shale Gas (MMcf)**	**Total (MBOE)**
Gross								
Proved producing	11,306	26,388	45,402	83,096	8,242	89,205	509,215	191,073
Proved developed non-producing	15	-	420	435	17	4,839	989	1,423
Proved undeveloped	300	3,845	31,744	35,889	3,566	1,726	216,411	75,811
Total proved	11,621	30,232	77,566	119,419	11,825	95,769	726,614	268,308
Total probable	2,645	8,721	45,432	56,798	6,273	30,521	276,169	114,186
Proved plus probable	**14,265**	**38,953**	**122,998**	**176,216**	**18,098**	**126,290**	**1,002,783**	**382,493**
Net								
Proved producing	9,677	21,857	36,740	68,274	6,675	87,416	408,473	157,597
Proved developed non-producing	14	-	351	365	12	3,966	827	1,177
Proved undeveloped	277	3,119	25,300	28,696	2,841	1,336	173,076	60,606
Total proved	9,968	24,976	62,391	97,335	9,528	92,717	582,375	219,379
Total probable	2,246	7,057	36,561	45,864	5,057	29,140	221,281	92,658
Proved plus probable	**12,214**	**32,033**	**98,952**	**143,199**	**14,585**	**121,857**	**803,657**	**312,036**

(1) Tables may not add due to rounding.

Reserves Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a gross basis, from December 31, 2015 to December 31, 2016.

PROVED RESERVES – GROSS VOLUMES (FORECAST PRICES) [(1)]

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at December 31, 2015	13,871	31,705	-	45,576	3,274	183,564	4,149	80,135
Acquisitions	1,765	-		1,765	24	14,162	-	4,149
Dispositions	(2,885)	-	-	(2,885)	(882)	(90,343)	(2,237)	19,198)
Discoveries	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	100	-	-	100	-	-	-	100
Economic Factors	(606)	(533)	-	(1,139)	(173)	(4,731)	-	(2,101)
Technical Revisions	1,123	2,088	-	3,211	263	20,012	(128)	6,789
Production	(1,746)	(3,027)	-	(4,773)	(445)	(26,894)	(256)	(9,744)
Proved Reserves at December 31, 2016	11,621	30,232	**-**	41,853	2,061	95,769	1,527	60,130

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at December 31, 2015	-	-	86,202	86,202	7,430	-	620,932	197,120
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	-	-	(6,034)	(6,034)	(640)	-	(4,873)	(7,486)
Discoveries	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	5,429	5,429	589	-	36,268	12,063
Economic Factors	-	-	-	-	-	-	(30,053)	(5,009)
Technical Revisions	-	-	1,182	1,182	3,662	-	183,321	35,398
Production	-	-	(9,214)	(9,214)	(1,277)	-	(80,507)	(23,909)
Proved Reserves at December 31, 2016	**-**	**-**	77,566	77,566	9,764	**-**	725,087	208,178

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at December 31, 2015	13,871	31,705	86,202	131,778	10,704	183,564	625,081	277,255
Acquisitions	1,765	-	-	1,765	24	14,162	-	4,149
Dispositions	(2,885)	-	(6,034)	(8,919)	(1,522)	(90,343)	(7,110)	(26,683)
Discoveries	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	100	-	5,429	5,529	589	-	36,268	12,163
Economic Factors	(606)	(533)	-	(1,139)	(173)	(4,731)	(30,053)	(7,110)
Technical Revisions	1,123	2,088	1,182	4,393	3,925	20,012	183,193	42,187
Production	(1,746)	(3,027)	(9,214)	(13,987)	(1,722)	(26,894)	(80,763)	33,653)
Proved Reserves at December 31, 2016	11,621	30,232	77,566	119,419	11,825	95,769	726,614	268,307

(1) Tables may not add due to rounding.

PROBABLE RESERVES – GROSS VOLUMES (FORECAST PRICES) (1)

CANADA	**Light & Medium Oil (Mbbls)**	**Heavy Oil (Mbbls)**	**Tight Oil (Mbbls)**	**Total Oil (Mbbls)**	**Natural Gas Liquids (Mbbls)**	**Conventional Natural Gas (MMcf)**	**Shale Gas (MMcf)**	**Total (MBOE)**
Probable Reserves at December 31, 2015	3,367	9,804	-	13,171	949	53,802	1,530	23,342
Acquisitions	373	-	-	373	1	3,227	-	911
Dispositions	(845)	-	-	(845)	(256)	(29,438)	(895)	(6,157)
Discoveries	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	45	-	-	45	-	-	-	45
Economic Factors	534	(193)	-	341	(69)	(396)	-	207
Technical Revisions	(829)	(890)	-	(1,719)	80	3,325	(15)	(1,089)
Production	-	-	-	-	-	-	-	-
Probable Reserves at December 31, 2016	2,645	8,721	-	11,366	704	30,521	619	17,260

UNITED STATES	**Light & Medium Oil (Mbbls)**	**Heavy Oil (Mbbls)**	**Tight Oil (Mbbls)**	**Total Oil (Mbbls)**	**Natural Gas Liquids (Mbbls)**	**Conventional Natural Gas (MMcf)**	**Shale Gas (MMcf)**	**Total (MBOE)**
Probable Reserves at December 31, 2015	-	-	45,051	45,051	4,044	-	336,758	105,221
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	-	-	(3,680)	(3,680)	(366)	-	(2,670)	(4,491)
Discoveries	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	13,810	13,810	1,540	-	27,948	20,008
Economic Factors	-	-	-	-	-	-	1,998	333
Technical Revisions	-	-	(9,749)	(9,749)	351	-	(88,484)	(24,415)
Production	-	-	-	-	-	-	-	-
Probable Reserves at December 31, 2016	**-**	**-**	45,432	45,432	5,569	**-**	275,550	96,926

TOTAL ENERPLUS	**Light & Medium Oil (Mbbls)**	**Heavy Oil (Mbbls)**	**Tight Oil (Mbbls)**	**Total Oil (Mbbls)**	**Natural Gas Liquids (Mbbls)**	**Conventional Natural Gas (MMcf)**	**Shale Gas (MMcf)**	**Total (MBOE)**
Probable Reserves at December 31, 2015	3,367	9,804	45,051	58,222	4,993	53,802	338,288	128,563
Acquisitions	373	-	-	373	1	3,227	-	911
Dispositions	(845)	-	(3,680)	(4,525)	(622)	(29,438)	(3,566)	(10,648)
Discoveries	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	45	-	13,810	13,855	1,540	-	27,948	20,053
Economic Factors	534	(193)	-	341	(69)	(396)	1,998	540
Technical Revisions	(829)	(890)	(9,749)	(11,468)	430	3,325	(88,499)	(25,234)
Production	-	-	-	-	-	-	-	-
Probable Reserves at December 31, 2016	2,645	8,721	45,432	56,798	6,273	30,521	276,169	114,186

(1) Tables may not add due to rounding.

PROVED PLUS PROBABLE RESERVES – GROSS VOLUMES (FORECAST PRICES) (1)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at December 31, 2015	17,238	41,509	-	58,747	4,223	237,366	5,678	103,477
Acquisitions	2,137	-	-	2,137	25	17,389	-	5,060
Dispositions	(3,730)	-	-	(3,730)	(1,138)	(119,781)	(3,133)	(25,354)
Discoveries	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	145	-	-	145	-	-	-	145
Economic Factors	(72)	(726)	-	(798)	(242)	(5,127)	-	(1,894)
Technical Revisions	294	1,198	-	1,492	343	23,337	(143)	5,700
Production	(1,746)	(3,027)	-	(4,773)	(445)	(26,894)	(256)	(9,744)
Proved Plus Probable Reserves at December 31, 2016	14,265	38,953	-	53,218	2,765	126,290	2,146	77,389

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at December 31, 2015	-	-	131,253	131,253	11,474	-	957,690	302,341
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	-	-	(9,713)	(9,713)	(1,007)	-	(7,543)	(11,977)
Discoveries	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	19,239	19,239	2,129	-	64,216	32,071
Economic Factors	-	-	-	-	-	-	(28,056)	(4,676)
Technical Revisions	-	-	(8,566)	(8,566)	4,013	-	94,837	11,253
Production	-	-	(9,214)	(9,214)	(1,277)	-	(80,507)	(23,909)
Proved Plus Probable Reserves at December 31, 2016	**-**	**-**	122,998	122,998	15,333	**-**	1,000,637	305,104

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at December 31, 2015	17,238	41,509	131,253	190,000	15,697	237,366	963,368	405,818
Acquisitions	2,137	-	-	2,137	25	17,389	-	5,060
Dispositions	(3,730)	-	(9,713)	(13,443)	(2,145)	(119,781)	(10,676)	(37,331)
Discoveries	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	145	-	19,239	19,384	2,129	-	64,216	32,216
Economic Factors	(72)	(726)	-	(798)	(242)	(5,127)	(28,056)	(6,570)
Technical Revisions	294	1,198	(8,566)	(7,074)	4,356	23,337	94,694	16,953
Production	(1,746)	(3,027)	(9,214)	(13,987)	(1,722)	(26,894)	(80,763)	(33,653)
Proved Plus Probable Reserves at December 31, 2016	14,265	38,953	122,998	176,216	18,098	126,290	1,002,783	382,493

(1) Tables may not add due to rounding.

FUTURE DEVELOPMENT COSTS

Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect the evaluators' best estimate of the capital required to bring the proved and proved plus probable reserves on production. The aggregate of the exploration and development costs incurred in the most recent year and the change during the year in estimated future development capital generally reflect the total finding and development costs related to reserves additions for that year.

The following is a summary of the independent reserves evaluators' estimated FDC required to bring the total proved and proved plus probable reserves on production:

	CANADA				UNITED STATES			
	Proved Reserves		Proved Plus Probable Reserves		Proved Reserves		Proved Plus Probable Reserves	
Year (in $ millions)	Undiscounted	Discounted at 10%/year	Undiscounted	Discounted at 10%/year	Undiscounted	Discounted at 10%/year	Undiscounted	Discounted at 10%/year
2017	43	42	45	44	334	318	352	335
2018	47	42	51	45	346	301	427	369
2019	45	36	51	40	52	42	350	278
2020	18	14	30	22	6	4	268	192
2021	11	8	14	9	-	-	1	1
Remainder	42	22	40	23	-	-	-	-
Total	206	164	231	183	738	665	1,398	1,174

F&D AND FD&A COSTS – including future development capital

($ millions except for per BOE amounts)	2016	2015	2014	3 Year
Proved Plus Probable Reserves				
Finding & Development Costs				
Capital Expenditures	$ 209.1	$ 493.4	$ 811.0	$ 1,513.6
Net change in Future Development Costs	$ (4.0)	$ (142.2)	$ (71.3)	$ (217.5)
Gross Reserves additions (MMBOE)	42.6	41.6	75.5	159.7
F&D costs ($/BOE)	**$ 4.82**	**$ 8.44**	**$ 9.80**	**$ 8.11**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$ (335.1)	$ 216.2	$ 625.9	$ 507.0
Net change in Future Development Costs	$ (94.5)	$ (212.5)	$ (59.2)	$ (366.3)
Gross Reserves additions (MMBOE)	10.3	14.9	65.8	91.0
FD&A costs ($/BOE)	**$ (41.60)**	**$ 0.25**	**$ 8.62**	**$ 1.55**
Proved Reserves				
Finding & Development Costs				
Capital Expenditures	$ 209.1	$ 493.4	$ 811.0	$ 1,513.6
Net change in Future Development Costs	$ (124.4)	$ 210.0	$ 13.8	$ 99.4
Gross Reserves additions (MMBOE)	47.2	50.7	69.1	167.0
F&D costs ($/BOE)	**$ 1.79**	**$ 13.88**	**$ 11.94**	**$ 9.66**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$ (335.1)	$ 216.2	$ 625.9	$ 507.0
Net change in Future Development Costs	$ (202.1)	$ 139.7	$ 4.9	$ (57.5)
Gross Reserves additions (MMBOE)	24.7	31.1	60.9	116.7
FD&A costs ($/BOE)	**$ (21.74)**	**$ 11.44**	**$ 10.36**	**$ 3.85**

CONTINGENT RESOURCES ASSESSMENT

The following table provides a breakdown of the economic, best estimate contingent resources associated with a portion of our Fort Berthold, Marcellus, and Canadian waterflood assets as at December 31, 2016. These contingent resources are economic using McDaniel's January 1, 2017 forecast commodity prices, use established technologies and are all classified in the "development pending" maturity sub-class.

The evaluations of contingent resources associated with a portion of our waterflood properties and our leases at Fort Berthold were conducted by Enerplus and audited by McDaniel. NSAI evaluated 100% of our Marcellus shale gas assets in the U.S., including the estimate of contingent resources. There is uncertainty that it will be commercially viable to produce any portion of the resources.

Please see Enerplus' Annual Information Form ("**AIF**") – Appendix A for additional disclsoures related to our contingent resources as at December 31, 2016. The AIF is available at www.enerplus.com as well as on the Company's SEDAR profile at www.sedar.com.

Development Pending Contingent Resources	**Unrisked "Best Estimate" Contingent Resources**	**Contingent Resources Net Drilling Locations**
Canadian Properties		
Waterfloods – IOR/EOR on a portion of waterfloods (MMBOE)	34.4	54.3
Total Canada (MMBOE)	**34.4**	**54.3**
United States Properties		
Fort Berthold – Bakken/Three Forks Tight Oil (MMBOE)	119.8	215.3
Marcellus - Shale gas (Bcf)	837.0	96.7
Total United States (MMBOE)	**259.3**	**312.0**
Total Company (MMBOE)	**293.7**	**366.3**

NET PRESENT VALUE OF FUTURE PRODUCTION REVENUE

The following table provides an estimate of the net present value of Enerplus' future production revenue after deduction of royalties, estimated future capital and operating expenditures, before income taxes. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves.

The forecast price assumptions reflect a reduction in the forecast prices for both our portfolio of crude oil and natural gas at AECO and Henry Hub when compared to the price assumptions used at December 31, 2015. The 6% decrease in our 2P reserves at December 31, 2016 resulted in the estimated before tax NPV, using a 10% discount rate, to decrease by 3%.

Net Present Value of Future Production Revenue – Forecast Prices and Costs (before tax)

Reserves at December 31, 2016, ($ Millions, discounted at)	**0%**	**5%**	**10%**	**15%**
Proved developed producing	$ 4,021	$ 2,767	$ 2,117	$ 1,730
Proved developed non-producing	20	11	7	6
Proved undeveloped	1,257	700	420	255
Total Proved	**$ 5,297**	**$ 3,479**	**$ 2,544**	**$ 1,991**
Probable	3,065	1,432	820	524
Total Proved Plus Probable Reserves (before tax)	**$ 8,362**	**$ 4,911**	**$ 3,364**	**$ 2,515**

NET ASSET VALUE

Enerplus' estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before taxes, as estimated by our independent reserves engineers, McDaniel and NSAI, at year-end, plus the estimated value of our undeveloped acreage and other equity investments, less asset retirement obligations, long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserves engineers.

In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development, including development of contingent resources. At

December 31, 2016, the best estimate of economic development pending contingent resources contained within our leases was 293.7 million BOE, unrisked. As we execute our capital programs, we expect to convert contingent resources to reserves which could result in a significant increase in our booked proved plus probable reserves. The land values described in the Net Asset Value table below do not necessarily reflect the full value of the contingent resources associated with these lands.

Net Asset Value (Forecast Prices and Costs at December 31, 2016)

($ millions except share amounts, discounted at)	0%	5%	10%	15%
Total net present value of proved plus probable reserves (before tax)	$ 8,362	$ 4,911	$ 3,364	$ 2,515
Undeveloped acreage (2016 Year End) (1)	146	146	146	146
Asset retirement obligations(4)	(93)	(125)	(63)	(34)
Debt, net of cash and restricted cash	(376)	(376)	(376)	(376)
Net working capital(2)	(93)	(93)	(93)	(93)
Net Asset Value	$ 7,946	$ 4,463	$ 2,978	$ 2,158
Net Asset Value per Share(3)	$ 33.04	$ 18.56	$ 12.38	$ 8.97

(1) Canadian acreage in Ante Creek is carried at market price; validated Duvernay acreage is carried at historical acquisition cost. Prospective acreage in the U.S. is carried at historical acquisition cost. All other acreage is valued at a nominal value of $50/acre. U.S. values were converted to Canadian dollars using a US/CDN exchange rate of 1.3427.
(2) Net working capital includes current derivative financial assets and liabilities.
(3) Based on 240,483,000 shares outstanding as at December 31, 2016.
(4) Asset retirement obligations ("ARO") may not equal the balance sheet as a portion of ARO costs are already reflected in the present value of 2P reserves, and the discount rates applied may differ.

CASH DIVIDENDS PAID TO SHAREHOLDERS*

(Cdn$/share)

(US$/share)

* paid January – December

Amounts paid to U.S. investors are converted to U.S. dollars on the applicable payment date. Amounts shown are prior to any amounts deducted for Canadian withholding tax.

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

BcfGE(1) billion cubic feet of gas equivalent

BOE(1) barrels of oil equivalent

Brent crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $US dollars.

F&D Costs finding and development costs

FD&A Costs finding, development and acquisition costs

FDC future development capital

IFRS International Financial Reporting Standards

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent

Mcf thousand cubic feet

MMbbl(s) million barrels

MMBOE million barrels of oil equivalent

MMBtu million British Thermal Units

MMcf million cubic feet

MWh megawatt hour(s) of electricity

NGLs natural gas liquids

NI 51-101 National Instrument 51-101 Oil and Gas Activities adopted by the Canadian Securities regulatory Authorities (pertaining to reserves reporting in Canada)

NYMEX New York Mercantile Exchange, the benchmark for North American natural gas pricing

2P Reserves proved plus probable reserves

RLI reserves life index

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

(1) The Corporation has adopted the standard of 6 Mcf of natural gas: 1 bbl of oil when converting natural gas to BOEs, MBOEs and MMBOEs, and 1 bbl of oil and NGLs: 6 Mcf of natural gas when converting oil and NGLs to BcfGEs. For further information, see "*Presentation of Oil and Gas Reserves, Resources and Production Information – Barrels of Oil and Cubic Feet of Gas Equivalent*".

DEFINITIONS

Adjusted Payout Ratio Calculated as the sum of dividends to shareholders (net of stock dividends and DRIP proceeds) plus capital spending (including office capital) divided by funds flow.

Contingent Resources Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. "Economic" contingent resources are those resources that are economically recoverable based on McDaniel's January 1, 2017 forecast prices.

The economic contingent resources estimates in this Appendix A are presented as the "best estimate" of the quantity that will actually be recovered, meaning that it is equally likely that the actual remaining quantities recovered will be greater or less than the "best estimate", and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the "best estimate".

Contingent Resources, Development Pending This contingent resources project maturity sub-class is assigned to contingent resources for a particular project where resolution of the final conditions for development is being actively pursued (there is a high chance of development) and the project is expected to be developed in a reasonable timeframe.

BOE Barrels of oil equivalent converting 6 Mcf of natural gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. The factor used to convert natural gas and natural gas liquids to oil equivalent is not based on either energy content or prices but is a commonly used industry benchmark. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas 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.

F&D Costs Finding and development costs. It is a measure of the effectiveness of a company's capital program. F&D costs presented are calculated (i) in the case of F&D costs for proved reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves in the year, and (ii) in the case of F&D costs for proved plus probable reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding and development costs related to its reserves additions for that year.

FD&A Costs Finding, development and acquisition costs. It is a measure of a company's ability to add resereves in a cost effective manner. FD&A costs presented are calculated (i) in the case of FD&A costs for proved reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves including net acquisitions in the year, and (ii) in the case of FD&A costs for proved plus probable reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves including net acquisitions in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding, development and acquisition costs related to its reserves additions for that year.

Future Development Costs (FDC) Future Development Costs is defined as those costs which reflect the independent evaluator's best estimate of what it will cost to bring the proved and probable non-producing and undeveloped reserves on production in the future. Changes to this figure occur annually as a result of development activities, acquisition and disposition activities, additions to non-producing and undeveloped reserves and capital cost estimate revisions.

NGLs Natural gas liquids – hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

Oil, Heavy Oil with a density between 10 to 22.3 degrees API or where a royalty regime exists specific to heavy oil, it is defined based upon that royalty regime.

Oil, Light & Medium Oil that has a density of 22.3 degrees API or higher.

Oil, Tight Oil that is petroleum that consists of light crude oil contained in petroleum-bearing formations of low permeability, often shale or tight sandstone.

Operating Income Calculated as revenues from oil and gas sales less cash hedging costs, transportation costs, royalties and operating costs.

Production, Company Interest Our working interest (operated and non-operated) share of production before the deduction of royalties, but inclusive of any royalty interest production owned by Enerplus. Therefore, the “company interest” production of the Corporation may not be comparable to similar measures presented by other issuers, and investors are cautioned that “company interest” production should not be construed as an alternative to “gross” or “net” production calculated in accordance with NI 51-101.

Production, Gross Our working interest (operated and non-operated) share of production before the deduction of any royalty interest production. Unless otherwise stated, all production volumes utilized in any discussions or calculations are gross production volumes.

Production, Proved Proved production volumes as determined by the independent reserves engineering report for 2003 and forward, and management’s estimate for all prior years.

Reserves Life Index, Proved Calculated as proved reserves at year-end divided by the following year’s estimated proved production volumes as determined by the independent reserves engineering report.

Reserves Life Index, Proved plus Probable Calculated as proved plus probable reserves at year-end divided by the following year’s estimated proved plus probable production volumes as determined by the independent reserves engineering report.

Reserves, Gross Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves but exclusive of royalty interest reserves owned by Enerplus.

Reserves, Net Our working interest (operated and non-operated) share of reserves after the deduction of royalty interest reserves but inclusive of any royalty interest reserves owned by Enerplus.

Reserves, Probable Additional reserves, calculated in accordance with NI 51-101, that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Reserves, Proved Reserves that can be estimated with a high degree of certainty to be recoverable in accordance with NI 51-101. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Reserves, Developed Non-Producing Reserves that have either not been on production or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Reserves, Developed Producing Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Reserves, Undeveloped Reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production.

Total Return Calculated using the change in the share price from the start of the period (including any capital appreciation or depreciation) and the total cash dividends paid during the period divided by the starting share price.

BOARD OF DIRECTORS

Elliott Pew(1)(2)

Corporate Director
Boerne, Texas

David H. Barr(9)(12)

Corporate Director
Houston, Texas

Michael R. Culbert(3)(5)(9)

Corporate Director
Calgary, Alberta

Ian C. Dundas

President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

Hilary A. Foulkes(5)(7)(9)(11)

Corporate Director
Calgary, Alberta

Robert B. Hodgins(3)(6)

Corporate Director
Calgary, Alberta

Susan M. MacKenzie(7)(10)(11)

Corporate Director
Calgary, Alberta

Glen D. Roane(4)(5)

Corporate Director
Canmore, Alberta

Sheldon B. Steeves(5)(8)

Corporate Director
Calgary, Alberta

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

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas

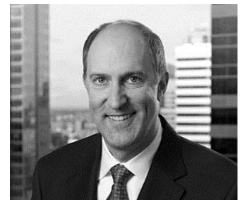
President & Chief Executive Officer

Raymond J. Daniels

Senior Vice President, Operations, People & Culture

Jodine J. Jenson Labrie

Senior Vice President & Chief Financial Officer



Eric G. Le Dain

Senior Vice President, Corporate Development, Commercial

Nathan D. Fisher

Vice President, U.S. Development & Geosciences

Daniel J. Fitzgerald

Vice President, Business Development

John E. Hoffman

Vice President, Canadian Operations

David A. McCoy

Vice President, General Counsel & Corporate Secretary

Edward L. McLaughlin

President, Enerplus (USA) Corporation

Shaina B. Morihira

Corporate Controller

(1) Ms. Lisa M. Ower resigned her duties as Vice President, People & Culture effective October 11, 2016. Mr. Raymond J. Daniels, Senior Vice President, Operations now has oversight of People & Culture.

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 Reserves 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
U.S. Bank Tower
Suite 2200, 950 17th Street
Denver, Colorado 80202-2805

Telephone: 720.279.5500
Fax: 720.279.5550

Annual General Meeting
Shareholders are encouraged to attend the Annual General Meeting being held on:

Friday, May 5, 2017
10:00 am, MT
The Telus Convention Centre
Glen 206
120 – 9th Avenue SE
Calgary, Alberta

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