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

The following discussion and analysis of financial results is dated February 23, 2012 and is to be read in conjunction with the audited consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company"), as at and for the years ended December 31, 2011 and 2010.

On January 1, 2011, Enerplus Resources Fund (the "Fund") converted from an income trust into a corporate entity with Enerplus being the successor issuer to the Fund. References in this MD&A to common shares, shareholders and dividends as they relate to the comparative periods reflect the history of the Fund and, therefore, reflect trust units, trust unitholders and distributions, respectively.

The Company is required to apply International Financial Reporting Standards ("IFRS") for financial periods beginning on January 1, 2011, including comparative amounts for the respective periods in 2010 and an opening balance sheet as at January 1, 2010. As a result (except where specifically referenced herein), this MD&A references financial statements prepared in accordance with IFRS including comparative prior period amounts. Readers are encouraged to refer to Note 18 of the Financial Statements for more information.

All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Financial Statements. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids 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.

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.

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 IFRS and therefore may not be comparable with the calculation of similar measures by other entities:

"Funds flow" is a term used to evaluate operating performance and assess leverage. Enerplus considers funds flow an important measure of its ability to generate funds necessary to finance dividends, operating activities, capital expenditures and debt repayments. Funds flow is calculated based on cash flow from operating activities before changes in non-cash operating working capital and decommissioning expenditures. Funds flow as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles cash flow from operating activities to funds flow:

($ thousands)	2011	2010
Cash flow from operating activities	$ 623,440	$ 696,183
Decommissioning expenditures	21,656	17,240
Changes in non-cash operating working capital	(71,487)	15,545
Funds Flow	$ 573,609	$ 728,968

"Payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing dividends to shareholders by funds flow.

"Adjusted payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate our adjusted payout ratio as dividends to shareholders plus capital spending (including office capital) divided by funds flow.

"Netback" is used to evaluate operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and gas sales revenue (net of transportation), less royalties and operating costs.

OVERVIEW

We made significant progress increasing our production during 2011. We entered the year with production of 77,200 BOE/day and exited the year at approximately 82,000 BOE/day, which was in-line with our guidance. Our annual average production was 75,332 BOE/day, slightly lower than our guidance of 76,000 BOE/day, as we experienced completion and tie-in delays during the year in certain areas with higher activity levels.

Our capital spending in 2011 totaled $865.7 million, approximately $95.7 million higher than our guidance of $770 million. The increase was mainly due to additional fourth quarter activity that included executing additional projects, accelerated spending on equipment inventory, regulatory work and permitting, along with continued inflationary cost pressure in Fort Berthold. Mild weather during the fourth quarter allowed for increased field operating activities related to well servicing and repairs and maintenance. This resulted in annual operating costs of $10.23/BOE compared to guidance of $9.60/BOE.

We continued to focus our asset base during 2011 through our acquisition and divestment activities. We spent approximately $145.6 million on undeveloped land acquisitions in Canada and the U.S., adding to our portfolio of future growth opportunities. We also spent $109.6 million on our Marcellus carry commitment, leaving a remaining commitment balance of $36.6 million which we expect to pay during 2012. Through our disposition activities we realized aggregate proceeds of $641.2 million, with $567.9 million coming from our Marcellus disposition in the second quarter where we recognized a $271.9 million gain.

Our funds flow for 2011 totaled $573.6 million, down from $729.0 million in 2010. Stronger oil prices in 2011 were more than offset by lower natural gas prices, lower average production levels and higher current income taxes in our U.S. subsidiary.

Despite the reduction in funds flow we continued to maintain our balance sheet strength with a trailing twelve month debt-to-funds flow ratio of 1.6x at year-end. On February 8, 2012 we completed an equity offering for $344.9 million to help fund our 2012 capital program and maintain our financial flexibility.

RESULTS OF OPERATIONS

Production

Production for 2011 averaged 75,332 BOE/day, slightly lower than our guidance of 76,000 BOE/day primarily due to delays experienced on some of our drilling and completion activities. In comparison to 2010, our average annual production for 2011 decreased by approximately 7,800 BOE/day. This decrease was expected as we sold approximately 10,400 BOE/day of non-core production throughout 2010 along with approximately 1,100 BOE/day during 2011 with our Marcellus disposition. Our capital program was very active in the fourth quarter and as a result our 2011 exit production was in-line with guidance, averaging approximately 82,000 BOE/day during the last two weeks of December.

Our average production in 2011 was weighted 44% to crude oil and liquids and 56% to natural gas on a BOE basis. Average daily production volumes for the twelve months ended December 31, 2011 and 2010 are outlined below:

Average Daily Production Volumes	2011	2010	% Change
Crude oil (bbls/day)	30,181	31,135	(3)%
Natural gas liquids (bbls/day)	3,306	3,889	(15)%
Natural gas (Mcf/day)	251,068	288,692	(13)%
Total daily sales (BOE/day)	75,332	83,139	(9)%

We expect 2012 production to average 83,000 BOE/day, with an increased weighting of crude oil and liquids to approximately 50% of overall production. We expect our production volumes to increase throughout the year exiting 2012 at approximately 88,000 BOE/day. This guidance does not contemplate any acquisitions or dispositions.

Pricing

The prices received for our natural gas and crude oil production directly impact our earnings, funds flow and financial condition. The following table compares our average selling prices for 2011 with those of 2010. It also compares the benchmark price indices for the same periods.

Average Selling Price[1]	2011	2010	% Change
Crude oil (per bbl)	$ 83.48	$ 70.38	19%
Natural gas liquids (per bbl)	64.99	51.41	26%
Natural gas (per Mcf)	3.72	4.05	(8)%
Per BOE	48.85	42.85	14%

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

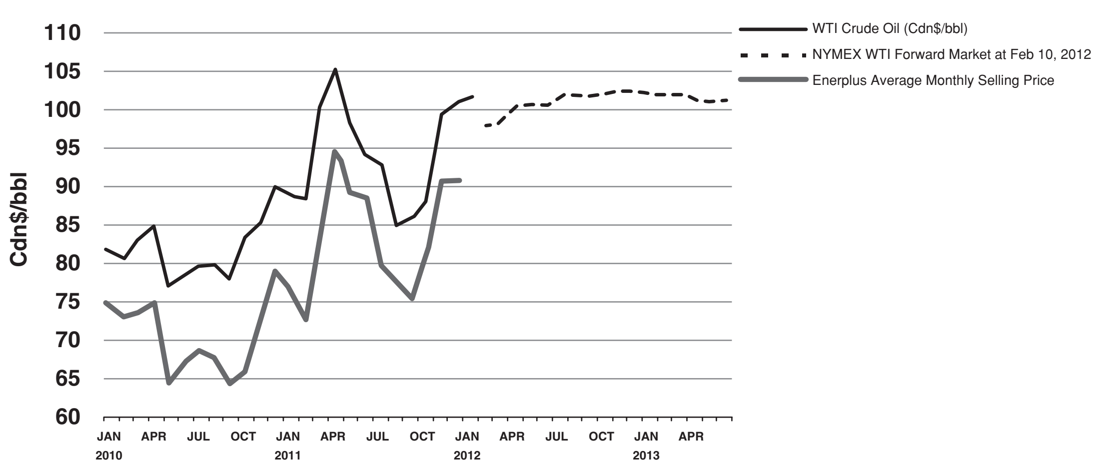
Average Benchmark Pricing	2011	2010	% Change
WTI crude oil (US$/bbl)	$ 95.12	$ 79.53	20%
WTI crude oil CDN$ equivalent (CDN$/bbl)	94.18	81.99	15%
AECO natural gas – monthly index (CDN$/Mcf)	3.68	4.13	(11)%
AECO natural gas – daily index (CDN$/Mcf)	3.62	4.00	(10)%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	4.07	4.42	(8)%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	4.03	4.56	(12)%
US/CDN exchange rate	1.01	0.97	4%

CRUDE OIL

Crude oil prices started the year at an average January price of US$89.58/bbl and finished the year at an average price of US$98.58/bbl in December. Globally, threats to supply with the continued unrest in the Middle East and low European crude inventories increased prices while weak economic conditions negatively impacted prices. The West Texas Intermediate ("WTI") experienced downward pressure relative to Brent prices as the take away capacity at Cushing could not keep pace with rising production and deliveries to the region.

The average price received for our crude oil (net of transportation) was $83.48/bbl for 2011, a 19% increase over 2010. This was in-line with expectations as WTI increased 20% over the same period and the CDN$/bbl WTI price increased by 15%. As a significant portion of our crude oil is produced in the U.S. we expect our realized price to fall between the U.S. and Canadian dollar equivalent benchmarks.

MONTHLY CRUDE OIL PRICES

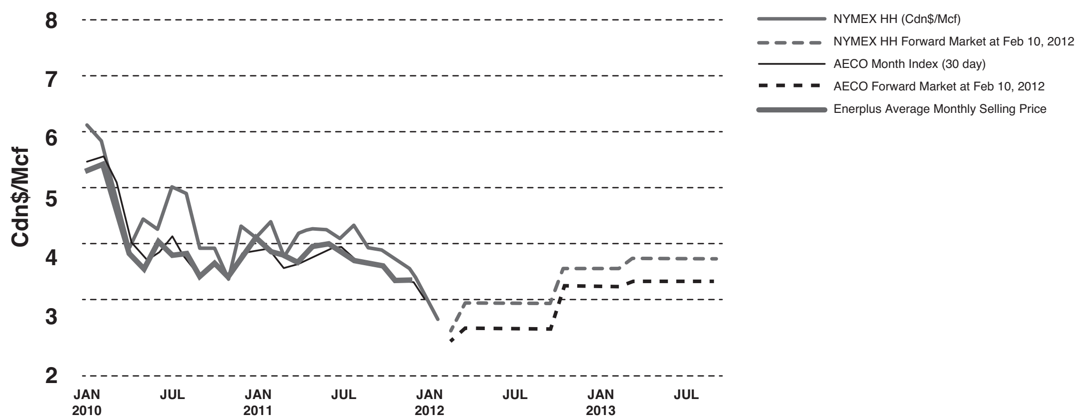


NATURAL GAS

Natural gas prices continued to decline throughout 2011 as demand failed to keep pace with increasing supply. The average AECO price for December was $2.94/Mcf as inventory levels remained high with the lack of cold winter weather.

During 2011 we sold our natural gas for an average price of $3.72/Mcf (net of transportation costs) which represented an 8% decline from 2010. This decrease was marginally better than the change in the AECO indices and in-line with the NYMEX monthly index, as a result of increased Marcellus gas production receiving premium prices and a decline in Canadian gas production which receives AECO pricing.

MONTHLY NATURAL GAS PRICES



Price Risk Management

We continue to maintain a price risk management program with consideration given to our overall financial position, the economics of our capital program and potential acquisitions. Consideration is also given to the costs of our risk management program as we seek to limit our exposure to price downturns. We have continued to add crude oil hedge positions for 2012 and 2013, including additional Brent-WTI spread positions. Our natural gas positions expired on March 31, 2011 and we have not added any additional positions. See Note 15 for further information regarding our current price risk management positions.

The following is a summary of the financial contracts in place at February 10, 2012 expressed as a percentage of our anticipated net production volumes:

	Crude Oil (US$/bbl)	
	January 1, 2012 – December 31, 2012	January 1, 2013 – December 31, 2013
WTI Purchased Puts (floor prices)	$ 103.00	–
%	3%	–
WTI Sold Puts (limiting downside protection)	$ 65.00	$ 63.00
%	7%	3%
WTI Swaps (fixed price)	$ 95.83	$ 101.20
%	59%	10%
WTI Sold Calls (capped price)	$ 133.00	–
%	3%	–
WTI Purchased Calls (repurchasing upside)	$ 103.00	$ 102.95
%	3%	3%
Brent – WTI Spread	$ 13.82	–
%	12%	–
WTI 1st to 2nd Month Spread	–	$ 0.35
%	–	7%

Based on weighted average price (before premiums), estimated average annual production of 83,000 BOE/day (net of royalties of 21%) for 2012 and 2013.

ACCOUNTING FOR PRICE RISK MANAGEMENT

During 2011 our price risk management program generated cash losses of $46.5 million on crude oil contracts and cash gains of $13.3 million on natural gas contracts. In comparison, in 2010 we realized cash losses of $17.6 million on crude oil contracts and cash gains of $67.3 million on natural gas contracts. The crude oil cash losses in 2011 are a result of crude oil prices rising above our fixed price swap positions. The cash gains in 2011 are due to natural gas contracts which provided floor protection above market prices during the first quarter.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At December 31, 2011 the fair value of our crude oil contracts, net of premiums, represented a loss of $19.6 million which is recorded as a current deferred financial credit on our balance sheet. At December 31, 2010 the fair value of our crude oil and natural gas contracts represented a loss of $38.3 million and a gain of $12.6 million respectively. The change in the fair value of our contracts during 2011 resulted in unrealized gains of $18.7 million for crude oil and unrealized losses of $12.6 million for natural gas. See Note 15 for details.

The following table summarizes the effects of our commodity derivative instruments on income:

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	**2011**				**2010**			
Cash gains/(losses):								
Crude Oil	$	(46.5)	$	(4.22)/bbl	$	(17.6)	$	(1.55)/bbl
Natural Gas		13.3	$	0.15/Mcf		67.3	$	0.64/Mcf
Total cash gains/(losses)	$	(33.2)	$	(1.21)/BOE	$	49.7	$	1.64/BOE
Non-cash gains/(losses) on financial contracts:								
Change in fair value – crude oil	$	18.7	$	1.70/bbl	$	(18.0)	$	(1.58)/bbl
Change in fair value – natural gas		(12.6)	$	(0.14)/Mcf		(7.7)	$	(0.07)/Mcf
Total non-cash gains/(losses)	$	6.1	$	0.22/BOE	$	(25.7)	$	(0.85)/BOE
Total gains/(losses)	$	(27.1)	$	(0.99)/BOE	$	24.0	$	0.79/BOE

Revenues

Crude oil and natural gas revenues were $1,343.1 million ($1,363.7 million, net of $20.6 million of transportation costs) in 2011, representing an increase of 3% or $42.9 million compared to $1,300.2 million ($1,327.1 million, net of $26.9 million of transportation costs) during 2010. Higher crude oil and liquids prices in 2011 more than offset the impact of lower natural gas prices and reduced annual production volumes.

Analysis of Sales Revenue[(1)] ($ millions)		**Crude Oil**		**NGLs**		**Natural Gas**		**Total**
2010 Sales Revenue	$	799.9	$	73.0	$	427.3	$	1,300.2
Price variance[(1)]		144.2		16.3		(28.6)		131.9
Volume variance		(24.5)		(10.9)		(53.6)		(89.0)
2011 Sales Revenue	$	919.6	$	78.4	$	345.1	$	1,343.1

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. Total royalties increased to $245.2 million in 2011 from $223.5 million during 2010 primarily due to an increased proportion of U.S. production where royalty rates are generally higher than in Canada. As a percentage of oil and gas sales, net of transportation costs, 2011 royalties were 18% compared to 17% in 2010. We are expecting an average royalty rate of 21% in 2012, which reflects additional production from North Dakota where royalty rates are approximately 30%.

Operating Expenses

Our 2011 operating costs were $10.23/BOE compared to guidance of $9.60/BOE. In the Fort Berthold area we had higher fluid handling charges due to restricted access to disposal wells and increased trucking costs resulting from truck shortages and various road bans. In Canada, mild fourth quarter weather gave rise to increased field activity for well servicing and repair and maintenance work, and higher than expected power costs combined to put upward pressure on our operating costs.

Operating costs during 2011 were $281.2 million ($10.23/BOE) compared to $291.0 million ($9.59/BOE) during 2010. Operating costs in 2011 decreased on a total dollar basis largely due to our 2010 non-core asset divestments.

We expect our 2012 operating costs will increase to $10.40/BOE primarily due to increases in U.S. water handling and gas facility charges, along with higher repairs and maintenance and power costs in Canada.

Netbacks

The following tables outline our crude oil and natural gas netbacks for 2011 and 2010. Natural gas liquids are included with the respective well or property and converted to BOE or Mcfe depending on the dominant production category.

	Year ended December 31, 2011		
	Crude Oil	Natural Gas	Total
Average Daily Production	33,185 BOE/day	252,883 Mcfe/day	75,332 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 77.17	$ 4.42	$ 48.85
Royalties	(16.27)	(0.52)	(8.92)
Cash operating costs	(11.77)	(1.53)	(10.33)
Netback before hedging	$ 49.13	$ 2.37	$ 29.60
Cash gains/(losses)	(3.84)	0.14	(1.21)
Netback after hedging	$ 45.29	$ 2.51	$ 28.39
Netback before hedging ($ millions)	$ 595.3	$ 218.6	$ 813.9
Netback after hedging ($ millions)	$ 548.8	$ 231.9	$ 780.7

	Year ended December 31, 2010		
	Crude Oil	Natural Gas	Total
Average Daily Production	34,528 BOE/day	291,669 Mcfe/day	83,139 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 64.58	$ 4.57	$ 42.85
Royalties	(13.54)	(0.50)	(7.36)
Cash operating costs	(11.72)	(1.36)	(9.66)
Netback before hedging	$ 39.32	$ 2.71	$ 25.83
Cash gains/(losses)	(1.40)	0.63	1.64
Netback after hedging	$ 37.92	$ 3.34	$ 27.47
Netback before hedging ($ millions)	$ 495.4	$ 288.3	$ 783.7
Netback after hedging ($ millions)	$ 477.8	$ 355.6	$ 833.4

(1) See "Non-GAAP Measures" in this MD&A.
(2) Net of oil and gas transportation costs.

Our crude oil properties accounted for 73% of our corporate netback before hedging for 2011. Crude oil netbacks have increased during 2011 due to higher prices partially offset by hedging losses. Natural gas netbacks decreased due to lower prices and lower hedging gains.

General and Administrative ("G&A") Expenses

Cash G&A expenses in 2011 were $82.1 million or $2.99/BOE compared to $83.6 million or $2.76/BOE in 2010. These costs remained consistent year over year, with higher salary costs in 2011 being offset by lower long term incentive plan costs as a result of a lower year-end share price.

Non-cash G&A expenses include costs for our previous rights incentive plan and for stock option grants issued in 2011. We use the Black Scholes model to calculate the grant date fair value for our stock options and expense the value over the vesting period of the options. See Note 14 for further details.

The following table summarizes the cash and non-cash expenses recorded in G&A:

General and Administrative Costs ($ millions)		2011		2010
Cash G&A	$	82.1	$	83.6
Stock option plan (non-cash)		12.3		14.1
Total G&A	$	94.4	$	97.7

(Per BOE)		2011		2010
Cash G&A	$	2.99	$	2.76
Stock option plan (non-cash)		0.45		0.46
Total G&A	$	3.44	$	3.22

We expect 2012 G&A expenses will average $3.55/BOE including $0.30/BOE of non-cash charges.

Finance Expense

Interest on our senior notes and bank credit facility in 2011 totaled $47.0 million, compared to $41.9 million in 2010. Higher debt levels and increased drawn and undrawn fees in 2011 in connection with our bank credit facility resulted in higher interest costs.

Non-cash amounts recorded in finance expense include accretion of decommissioning liabilities, amortization of financing fees and premiums, and unrealized gains and losses resulting from the change in fair value of our interest rate swaps and the interest component on our cross currency interest rate swap (“CCIRS”). In addition, under IFRS our exchangeable limited partnership (“EELP”) units were considered liabilities and their non-cash change in fair value of $12.8 million was recorded to finance expense in 2010. See Note 10 for further details.

The following table summarizes the cash and non-cash finance expense.

Finance Expense ($ millions)		2011		2010
Interest on senior notes and bank facility	$	47.0	$	41.9
Non-cash finance expense		13.4		27.6
Total Finance Expense	$	60.4	$	69.5

At December 31, 2011, after including our underlying derivatives, approximately 46% of our debt was based on fixed interest rates while 54% had floating interest rates. In comparison, at December 31, 2010 approximately 59% of our debt was based on fixed interest rates and 41% was floating.

Foreign Exchange

We recorded net foreign exchange losses of $4.2 million in 2011 compared to gains of $1.0 million in 2010. On June 19, 2011 we made the second US$35.0 million principal repayment on our US$175.0 million senior notes that were issued in 2002. The repayment resulted in both a realized foreign exchange loss and an unrealized foreign exchange gain of approximately $19.4 million as a result of the underlying CCIRS which effectively fixed the principal repayment at a foreign exchange rate of $0.6522 US$/CDN$.

A weaker Canadian dollar at December 31, 2011 compared to December 31, 2010 resulted in unrealized gains on our foreign exchange swaps and CCIRS, which were partially offset by unrealized losses from translating our U.S. dollar denominated debt to Canadian dollars. See Note 11 for further information.

Foreign Exchange ($ millions)		2011		2010
Realized loss/(gain)	$	18.4	$	28.0
Unrealized loss/(gain)		(14.2)		(29.0)
Total Foreign Exchange loss/(gain)	$	4.2	$	(1.0)

Capital Investment

During 2011 our capital spending totaled $865.7 million compared to $536.4 million in 2010, representing an increase of $329.3 million or 61%. We increased spending on our key growth areas with the majority directed towards our tight oil assets ($375.0 million), our crude oil waterfloods ($164.0 million) and our Marcellus assets ($210.0 million).

Our 2011 spending was $95.7 million above our guidance of $770 million. The majority of the increase relates to our Fort Berthold property where continued inflationary pressures increased costs by approximately $35 million and accelerated spending on equipment inventory, regulatory work and permitting accounted for another $25 million in costs. We also spent approximately $37 million on additional projects in both Canada and the U.S. that were originally planned for 2012.

Property and land acquisitions during 2011 totaled $255.2 million compared to $1.0 billion in 2010. During the year we continued to invest in undeveloped land in Canada spending an aggregate of $112.5 million with the addition of 65,000 net acres in the Duvernay liquids rich natural gas prospect, 28,000 net acres on oil prospects, 17,000 net acres of Montney prospective lands in British Columbia and 23,000 net acres in the Stacked Mannville. In the U.S. we spent approximately $33.1 million on additional undeveloped Marcellus lands around our existing holdings. Spending on our Marcellus carry obligation was US$111.0 million and our remaining carry obligation at December 31, 2011 was US$36.0 million.

Property and land acquisitions in 2010 were $1.0 billion, including $588.0 million of acquisitions in the Fort Berthold area, $169.3 million on expanding our land holdings in the Marcellus as well as $92.3 million on our Marcellus carry obligation. In Canada, we purchased undeveloped land in the Freda Lake, Neptune and Oungre areas of the Saskatchewan Bakken for $118.7 million as well as undeveloped land in the British Columbia and Alberta Deep Basin for $25.9 million.

We plan to spend $800 million on exploration and development projects in 2012 with over 70% of our spending focused on oil and liquids rich natural gas projects. We expect to invest approximately $300 million in light crude oil development at Fort Berthold, $150 million in our crude oil waterflood portfolio and $80 million in liquids rich natural gas drilling in the Stacked Mannville, Montney and Duvernay. Our natural gas spending will be focused primarily in the Marcellus where we expect to spend approximately $190 million on drilling to delineate and retain leases largely on non-operated interests. Over and above our capital spending program we plan to invest an additional $40 million for the acquisition of new undeveloped land. We intend to finance this additional $40 million through the sale of non-core properties with limited production and have signed a sale agreement representing approximately half of this amount as of the date of this MD&A.

Dispositions

Property dispositions in 2011 totaled $641.2 million compared to $871.5 million in 2010. During the year we disposed of approximately 91,000 net acres of our Marcellus interests for proceeds of $567.9 million (US$580 million) representing the majority of our 2011 dispositions. In Canada, we disposed of non-core assets with minimal production and reserves for total proceeds of approximately $61.8 million. We recognized gains of $302.1 million in 2011 related to our disposition activities.

In 2010, property dispositions included $465.2 million in proceeds from three non-core property packages and $404.8 million in proceeds from the sale of our Kirby oil sands lease. These dispositions resulted in gains of $210.2 million.

Capital Investment Summary

Our Exploration & Evaluation ("E&E") spending, Developed & Producing ("D&P") spending and acquisitions and dispositions are outlined below:

Capital Investment ($ millions)	2011	2010
E&E assets	$ 371.7	$ 284.5
D&P assets	494.0	251.9
Capital Spending	865.7	536.4
Office Capital	11.3	4.0
Sub-total	877.0	540.4
E&E asset acquisitions	248.4	994.9
D&P asset acquisitions	6.8	17.4
Property and Land Acquisitions	255.2	1,012.3
Property Dispositions	(641.2)	(871.5)
Total Net Capital Investment	$ 491.0	$ 681.2

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

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved plus probable reserves. For 2011 DD&A was $433.4 million or $15.76/BOE compared to $460.0 million or $15.16/BOE in 2010. The decrease in our DD&A in 2011 was attributable to lower annual production volumes.

Impairments

On transition to IFRS the majority of our goodwill in Canada was allocated to our Canadian natural gas focused Cash Generating Units ("CGU"s). When indicators of impairment are present, impairment tests are carried out on CGUs to determine if D&P asset carrying values, including goodwill, are impaired. Any calculated impairments are allocated first to goodwill with the remainder recorded against the carrying value of D&P assets. Our impairment test compares the CGU recoverable amount, which is estimated using proved plus probable reserves discounted at 10%, to the CGU carrying value.

Our Canadian natural gas focused CGUs recorded D&P asset impairments of $334.3 million in 2011. In 2010 these CGUs recorded D&P asset impairments of $376.0 million and goodwill impairments of $316.7 million. These impairments were the result of lower forecast natural gas prices. Under IFRS impairment charges related to D&P assets are reversed in future periods if conditions causing the impairment change.

E&E assets are also tested for impairment. We recorded a $35.5 million impairment to our E&E assets in 2011 related to acreage that is expiring early in 2012. This land was originally purchased in 2010 and drilling results to date in the area have not met our criteria for expanded development. We also recorded an E&E impairment reversal of $10.1 million in 2011 related to certain U.S. oil assets that had been impaired in 2010.

Impairment Expense ($ millions)	**2011**	**2010**
D&P impairments	$ 334.3	$ 377.2
E&E impairments	35.5	11.7
E&E impairment reversals	(10.1)	–
Goodwill impairments	–	316.7
Total Impairment Expense	$ 359.7	$ 705.6

Other Assets

Other assets consist of our portfolio of equity investments in other oil and gas companies. These investments are carried at their estimated fair value with changes in fair value recorded in other comprehensive income. During 2011 we recorded unrealized gains of $58.6 million primarily related to our investment in Laricina Energy Ltd. In 2010 we recorded unrealized gains of $61.4 million which were also mainly in respect of our investment in Laricina Energy Ltd.

Decommissioning Liabilities

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total decommissioning liabilities included on our balance sheet are estimated by management based on our net ownership interest, estimated costs to abandon and reclaim and the estimated timing of the costs to be incurred in future periods.

We have estimated the net present value of our decommissioning liability to be $563.8 million at December 31, 2011 compared to $392.7 million at December 31, 2010. The majority of this increase relates to the decrease in the risk-free rate used to calculate the present value of the future cash outflows, which fell from 3.52% at December 31, 2010 to 2.49% at December 31, 2011. See Note 9 for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2011 we spent $21.7 million (2010 – $17.2 million) on our decommissioning liabilities and we expect to spend approximately $24.0 million in 2012. Our abandonment and reclamation costs are expected to be incurred over the next 66 years with the majority between 2032 and 2051. We do not reserve cash or assets for the purpose of funding our future decommissioning liabilities. Any reclamation or abandonment costs are anticipated to be funded out of cash flow.

Environment

We strive to carry out our activities and operations in compliance with all applicable regulations and good 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.

Our Board of Directors Safety and Social Responsibility (S&SR) Committee has overall responsibility with respect to the development of an effective S&SR management system, to ensure that our activities are planned and executed in a safe and responsible manner and to ensure we have adequate systems to support ongoing compliance. We are seeing an increase in the number of regulations related to environmental compliance along with more strict thresholds within the regulations that could impact our operations and increase the cost of compliance. We may be subject to environmental and other costs resulting from unknown and unforeseeable environmental impacts arising from our operations. 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 spills should they occur.

Greenhouse gas ("GHG") regulations enacted at the provincial and state levels resulted in approximately $0.9 million of compliance costs in 2011. The ongoing uncertainty surrounding the direction from government affects our ability to proactively manage potential risks and opportunities associated with GHG emissions. We intend to continue to improve energy performance and proactively manage our emissions.

We use the hydraulic fracturing process in our operations. Government and regulatory agencies continue to frame regulations related to this process. We would expect to adjust our operations going forward, if necessary, to meet these regulations when established.

Taxes

Our current tax expense was $81.2 million in 2011 compared to a $30.4 million recovery in 2010. The current tax expense in 2011 mainly relates to Alternative Minimum Tax ("AMT") paid by our U.S. subsidiary due to taxable income from the gain on our Marcellus disposition. In addition, we recorded a US$25.0 million adjustment to reduce income tax recoveries related to AMT estimates in 2010. We expect to recover this AMT in the future against regular income taxes otherwise payable.

Our deferred income tax recovery was $48.6 million in 2011 compared to a recovery of $101.5 million in 2010. The decrease in the deferred income tax recovery was due to higher net income in 2011.

Income Tax (thousands)	**Year ended December 31, 2011**	**Year ended December 31, 2010**
Average Effective Tax Rate	22.9%	42.4%
Current Tax	$ 81,195	$ (30,375)
Deferred Tax	(48,630)	(101,519)
Total Tax	$ 32,565	$ (131,894)

Our effective tax rate was 22.9% for 2011 compared to 42.4% in 2010. The change in the effective tax rate is primarily due to our conversion to a corporation on January 1, 2011 that resulted in a one-time recovery of $34.1 million. Our effective tax rate differs from statutory tax rates as it takes into consideration changes in tax rates, legislation, reserves, estimates and tax rates in foreign jurisdictions where we operate.

We expect to pay U.S. cash taxes of approximately 5% of U.S. cash flow in 2012. We currently do not expect to pay material cash taxes in Canada until after 2015 as we estimate we have sufficient tax pools to offset taxable income prior to that time. These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisition and disposition activity.

TAX POOLS

Our estimated tax pools at December 31, 2011 are as follows:

Pool Type ($ millions)	**Total**
COGPE	$ 542
CDE	245
UCC	440
CEE	208
Tax losses and other	533
Canadian tax pools	$ 1,968
U.S. tax pools	1,199
Total	$ 3,167

Included in U.S. tax pools is an AMT credit carry forward of $83.4 million that can be used to offset regular U.S. income taxes payable in the future. At December 31, 2011, we also had unused capital losses of $1.4 billion that are not included above. These capital losses have an indefinite carry-forward period but can only be used to offset capital gains.

Net Income

Net income in 2011 was $109.4 million compared to a net loss of $179.3 million in 2010. The $288.7 million increase in net income for 2011 was primarily due to reduced impairment losses of $345.9 million and an increase of approximately $42.9 million in oil and gas sales (net of transportation), both of which were offset by higher current and deferred taxes totaling $164.5 million.

Funds Flow

Funds flow in 2011 was $573.6 million ($3.19 per share) compared to $729.0 million ($4.15 per share) in 2010. The decrease in funds flow in 2011 is primarily due to higher current taxes in 2011 ($111.6 million) and higher hedging losses ($82.9 million), offset by higher oil and gas sales ($42.9 million), net of transportation.

Selected Financial Results

	Year ended December 31, 2011			**Year ended December 31, 2010**		
Per BOE of production (6:1)	**Funds Flow[1]**	**Non-Cash & Other Items**	**Total Net Income per BOE[3]**	**Funds Flow[1]**	**Non-Cash & Other Items**	**Total Net Income per BOE[3]**
Weighted average sales price[2]	$ 48.85	$ –	$ 48.85	$ 42.85	$ –	$ 42.85
Royalties	(8.92)	–	(8.92)	(7.36)	–	(7.36)
Commodity derivative instruments	(1.21)	0.22	(0.99)	1.64	(0.85)	0.79
Asset disposition gain/(loss)	–	10.98	10.98	–	6.92	6.92
Operating costs	(10.33)	0.10	(10.23)	(9.66)	0.07	(9.59)
General and administrative expenses	(2.99)	(0.45)	(3.44)	(2.76)	(0.46)	(3.22)
Interest, foreign exchange and other expenses	(1.59)	(0.67)	(2.26)	(1.69)	(0.55)	(2.24)
Current tax	(2.95)	–	(2.95)	1.00	–	1.00
Depletion, depreciation, amortization	–	(15.76)	(15.76)	–	(15.16)	(15.16)
Impairments	–	(13.08)	(13.08)	–	(23.25)	(23.25)
Deferred tax (expense)/recovery	–	1.78	1.78	–	3.35	3.35
Total net income/(loss) per BOE	$ 20.86	$ (16.88)	$ 3.98	$ 24.02	$ (29.93)	$ (5.91)

(1) See "Non-GAAP Measures" in this MD&A.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(3) Based on 75,332 BOE/day of production in 2011 and 83,139 BOE/day of production in 2010.

SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

The following table provides a geographical analysis of key operating and financial results for 2011 and 2010.

	Year ended December 31, 2011			Year ended December 31, 2010		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	19,125	11,056	30,181	21,712	9,423	31,135
Natural gas liquids (bbls/day)	3,177	129	3,306	3,889	–	3,889
Natural gas (Mcf/day)	219,129	31,939	251,068	266,671	22,021	288,692
Total Average Daily Production (BOE/day)	58,824	16,508	75,332	70,046	13,093	83,139
Pricing(1)						
Crude oil (per bbl)	$ 82.02	$ 86.01	$ 83.48	$ 70.05	$ 71.15	$ 70.38
Natural gas (per Mcf)	3.54	4.98	3.72	3.94	5.42	4.05
Natural gas liquids (per bbl)	65.63	49.40	64.99	51.41	–	51.41
Capital Expenditures						
Capital spending and office capital	$ 333.3	$ 543.7	$ 877.0	$ 300.7	$ 239.7	$ 540.4
Acquisitions	112.5	142.7	255.2	152.8	859.5	1,012.3
Dispositions	(61.8)	(579.4)	(641.2)	(871.5)	–	(871.5)
Revenues						
Oil and gas sales(1)	$ 935.1	$ 408.0	$ 1,343.1	$ 1,011.9	$ 288.3	$ 1,300.2
Royalties(2)	(143.0)	(102.2)	(245.2)	(154.7)	(68.8)	(223.5)
Commodity derivative instruments gain/(loss)	(27.1)	–	(27.1)	24.0	–	24.0
Expenses						
Operating	$ 245.2	$ 36.0	$ 281.2	$ 272.8	$ 18.2	$ 291.0
General and administrative	82.4	12.0	94.4	85.9	11.8	97.7
Depletion, depreciation and amortization	335.9	97.5	433.4	399.5	60.5	460.0
Impairments/(reversals)	369.8	(10.1)	359.7	693.9	11.7	705.6
Current tax expense/(recovery)	0.6	80.6	81.2	16.6	(47.0)	(30.4)

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) U.S. royalties include state production tax.

THREE YEAR SUMMARY OF KEY MEASURES

Oil and natural gas sales were relatively flat during the last three years as rising crude oil prices have largely been offset by declining natural gas prices and lower production levels resulting from our disposition activity.

Net income has been affected by fluctuating commodity prices and risk management costs, impairment losses, gains on asset dispositions, the fluctuating Canadian dollar and changes in tax provisions. The following table provides a summary of various financial measures.

($ millions, except per share amounts)	2011	2010	2009(5)
Oil and gas sales(1)	$ 1,343.1	$ 1,300.2	$ 1,232.8
Net income/(loss)	109.4	(179.3)	89.1
Per share (Basic)(2)	0.61	(1.02)	0.53
Per share (Diluted)(2)	0.61	(1.02)	0.53
Funds flow(6)	573.6	729.0	763.4
Per share (Basic)(2)	3.19	4.15	4.51
Dividends to shareholders(3)	388.9	384.1	368.2
Per share (Basic)(2)(3)	2.16	2.19	2.17
Total assets	5,723.3	5,489.2	5,905.5
Long-term debt, net of cash(4)	901.5	724.0	485.3

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Based on weighted average shares outstanding.
(3) Calculated based on shares paid or payable. Cash dividends to shareholders per unit may not correspond to actual dividends as a result of using the annual weighted average shares outstanding.
(4) Including current portion of long-term debt.
(5) 2009 comparatives are presented according to Canadian GAAP.
(6) See "Non-GAAP measures" in this MD&A.

LIQUIDITY AND CAPITAL RESOURCES

During the fourth quarter of 2011 we extended our $1.0 billion bank credit facility for a three-year term, maturing October 13, 2014. Drawn fees under the facility decreased and range between 160 and 325 basis points over bankers' acceptance rates. Standby fees also decreased to 20% of the drawn pricing. We are currently paying 160 basis points over bankers' acceptance rates, which are trading around 1.2%, for a combined rate of 2.8%. The amending agreement was filed on October 21, 2011 as a material document on the Company's SEDAR profile at www.sedar.com.

During 2011 we swapped US$175 million of notional principal at approximately par related to our US$225 million senior notes, which are set to mature between June 2017 and June 2021. The exchange rate was originally US/CDN $0.88 when these U.S. dollar denominated notes were issued in 2009. By utilizing these forward swaps we expect to repay the U.S. debt with significantly less Canadian dollars than we originally borrowed.

We made aggregate principal repayments of US$45.8 million (CDN$64.6 million including underlying derivatives) during 2011 on our US$175 million and US$54 million senior notes. The repayments were funded through a combination of funds flow and our bank credit facility. See Note 8 for more information.

Total debt at December 31, 2011, including the current portion, was $907.1 million compared to $732.4 million at December 31, 2010. Total debt at December 31, 2011 was comprised of $446.2 million of bank indebtedness and $460.9 million of senior notes. The increase of $174.7 million from December 31, 2010 is due to funding our capital spending and working capital requirements in excess of our funds flow.

Our working capital deficiency at December 31, 2011, excluding cash and current deferred financial assets and credits, increased by $109.5 million compared to December 31, 2010. The change in our working capital resulted from increased accounts payable balances at year-end 2011, due to higher activity levels and capital spending during the fourth quarter, along with reduced tax recoveries. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our payout ratio, which is calculated as dividends divided by funds flow, was 68% for 2011 compared to 53% in 2010. Our adjusted payout ratio, which is calculated as dividends plus capital spending and office capital divided by funds flow, was 221% for 2011 compared to 127% in 2010. Our dividends were held flat at $0.18/share per month in both 2010 and 2011 therefore the increases in the ratios are due to lower funds flow and higher capital spending during 2011. However, if we include our 2011 net acquisition and disposition activity our adjusted payout ratio would decrease to 153% in 2011. Throughout 2010 and 2011 we sold over $1.5 billion of assets, including both mature and early stage assets, and purchased over $1.25 billion of new assets, primarily consisting of early stage growth assets. Refer to "Non-GAAP Measures" section of this MD&A.

At December 31, 2011 we were in compliance with our debt covenants. We have continued to maintain a conservative balance sheet as demonstrated below:

Financial Leverage and Coverage	Year ended December 31, 2011	Year ended December 31, 2010
Long-term debt to funds flow (12 month trailing)(1)(2)	1.6 x	1.0 x
Funds flow to interest expense (12 month trailing)(2)(3)	12.2 x	17.4 x
Long-term debt to long-term debt plus equity(1)	22%	18%

(1) Long-term debt is measured net of cash and includes the current portion of the senior notes.
(2) See "Non-GAAP" measures in this MD&A.
(3) Interest expense is finance expense excluding non-cash items.

Despite increasing production and anticipated funds flow growth in 2012, our capital spending program and dividends are expected to exceed funds flow. We expect to have adequate liquidity to fund the shortfall through debt and equity financing, including the gross proceeds of our recent equity financing of $344.9 million and proceeds from our dividend reinvestment program ("DRIP"). In addition, we continue to hold a portfolio of equity investments that we may sell to help fund capital spending or acquisitions. At December 31, 2011 we had $553.8 million of available credit under our bank credit facility to help support our growth plans. We believe we also have the ability to increase the size of our bank credit facility in the context of the current market should we choose.

Counterparty Credit

OIL AND GAS SALES COUNTERPARTIES

Our oil and gas receivables are with customers in the oil and gas business 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' credit worthiness 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 some of our credit risk. This process is utilized for both our oil and 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 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, 2011 we had $8.9 million in mark-to-market assets offset by $67.5 million of mark-to-market liabilities resulting in a net liability position of $58.6 million.

Dividend Policy

We currently pay monthly dividends of $0.18/share and we intend to continue to distribute a significant portion of our funds flow to our shareholders. During 2011 we paid $388.9 million of dividends to our shareholders. We will continue to assess dividend levels with respect to anticipated funds flow, debt levels, capital spending plans and capital market conditions and will adjust dividend levels as necessary. The payment of dividends, or the amount thereof, is not guaranteed.

Commitments

In Canada we have contracted to transport 217 MMcf/day of natural gas with contract terms that range anywhere from one month to five years. Our natural gas production dedicated to aggregator sales contracts is expected to be approximately 6% of gas production or 16 MMcf/day annually. Under these arrangements, we receive a price based on the average netback price of the pool.

For our Bakken crude oil in the U.S. we have contracted transportation capacity for 1,000 bbl/day until May 2016 with an additional 7,500 bbl/day beginning January 1, 2013 through December 2017.

For our U.S. Bakken play we have contracts securing two drilling rigs, one with related fracturing services, through the first quarter of 2013 for a monthly commitment of $5.0 million. We have extended one of the drilling rigs until September 2014 for a monthly commitment of $0.3 million.

In Canada we have contracts securing two drilling rigs until September 2012 with one drilling rig extending until September 2013 with monthly commitments for each rig being between $0.1 million and $0.2 million.

Our Canadian and U.S. office leases expire in 2019. Annual costs of these lease commitments include rent and operating fees. Our commitments, contingencies and guarantees are more fully described in Note 16.

As at December 31, 2011 we have the following minimum annual commitments including long-term debt:

		Minimum Annual Commitment Each Year					Total Committed
($ millions)[1]	Total	2012	2013	2014	2015	2016	after 2016
Bank credit facility	$ 446.2	$ –	$ –	$ 446.2	$ –	$ –	$ –
Senior unsecured notes[2][3]	510.7	64.6	64.6	64.6	91.7	–	225.2
Transportation commitments	89.7	16.8	21.7	18.6	16.0	8.5	8.1
Processing commitments	3.4	2.4	0.3	0.3	0.2	–	0.2
Marcellus carry commitment[4]	36.6	36.6	–	–	–	–	–
Drilling and completions commitment	84.8	63.5	18.3	3.0	–	–	–
Decommissioning Liability[4]	644.9	24.0	20.0	20.0	20.0	20.0	540.9
Office leases	89.6	13.0	13.9	13.3	10.2	10.3	28.9
Total commitments[5]	$ 1,905.9	$ 220.9	$ 138.8	$ 565.9	$ 138.1	$ 38.8	$ 803.3

(1) US$ commitments have been converted to CDN$ using the December 31, 2011 foreign exchange rate of 0.9833.
(2) Interest payments have not been included.
(3) Includes the economic impact of derivative instruments directly related to the senior unsecured notes (CCIRS and foreign exchange swap – see Note 15).
(4) Based upon current spending estimates.
(5) Crown and surface royalties, 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.

Subsequent to December 31, 2011 we secured additional transportation capacity for our U.S. Bakken crude oil as we entered into a two year firm commitment for rail capacity to the U.S. Gulf Coast commencing February 2012 for 6,000 bbl/day through January 2013 and 4,000 bbl/day from February 2013 through January 2014. After this agreement we have aggregate transportation capacity of approximately 7,000 bbl/day for 2012, 12,500 bbl/day for 2013, 8,500 bbl/day from 2014 to 2016 and 7,500 bbl/day for 2017.

Accumulated Deficit Reclassification

As part of the plan of arrangement (under which we converted from an income trust to a corporation) our January 1, 2011 accumulated deficit balance of $2.3 billion was reclassified against share capital. See Note 14.

Shareholders' Capital

Effective January 1, 2011, pursuant to the plan of arrangement, unitholders of the Fund received one common share of Enerplus in exchange for each trust unit and 0.425 of a common share of Enerplus for each exchangeable partnership unit of EELP held. Under IFRS, EELP units and trust unit rights were considered liabilities and were recorded on the consolidated balance sheets at fair value. Upon conversion to a corporation these liabilities were effectively converted into equity and the EELP liability was recorded to share capital and the trust unit rights liability was recorded to contributed surplus.

During 2011, 2,510,000 shares (2010 – 1,587,000) were issued pursuant to the DRIP and the stock option plan. This resulted in $64.0 million (2010 – $35.4 million) of additional equity for the company. For further details see Note 14.

We had 181,159,000 shares outstanding at December 31, 2011 compared to 176,946,000 shares outstanding at December 31, 2010. The weighted average basic number of shares outstanding during 2011 was 179,889,000 shares compared to 175,736,000 shares during 2010.

On February 8, 2012 we completed a bought deal equity financing of 14,708,500 common shares at a price of $23.45 per share for gross proceeds of $344.9 million ($330.6 million net of issuance costs). At February 22, 2012 we had 196,303,000 shares outstanding.

QUARTERLY FINANCIAL INFORMATION

During 2010 and 2011 higher crude oil prices were largely offset by a significant decline in natural gas prices and a reduction in production levels due to our disposition activity. As a result, oil and gas sales year-over-year have remained relatively flat.

Net income has been affected by fluctuating commodity prices, risk management costs, asset impairments and the fluctuating Canadian dollar.

(CDN$ millions, except per share amounts)	Oil and Gas Sales(1)	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2011				
Fourth Quarter	$ 357.3	$ (299.4)	$ (1.66)	$ (1.65)
Third Quarter	312.9	111.3	0.62	0.62
Second Quarter	354.2	268.0	1.50	1.49
First Quarter	318.7	29.5	0.17	0.16
Total	$ 1,343.1	$ 109.4	$ 0.61	$ 0.61
2010				
Fourth Quarter	$ 313.2	$ 64.5	$ 0.37	$ 0.36
Third Quarter	305.5	(136.3)	(0.77)	(0.77)
Second Quarter	318.2	76.5	0.44	0.38
First Quarter	363.3	(184.0)	(1.05)	(1.08)
Total	$ 1,300.2	$ (179.3)	$ (1.02)	$ (1.02)

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

SUMMARY FOURTH QUARTER INFORMATION

In comparing the fourth quarter of 2011 with the same period in 2010:

- Average daily production was 77,221 BOE/day compared to 80,114 BOE/day in 2010. However, exit production in 2011 increased to 82,000 BOE/day due to a large fourth quarter capital program with our efforts focused at Fort Berthold where we brought 11 high impact wells on stream.
- Capital spending (including office) increased to $347.8 million compared to $227.9 million in 2010. Mild weather during the fourth quarter of 2011 gave rise to higher activity levels in the U.S. and Canada as there were no issues with rig availability or service crews. Our fourth quarter costs were higher than expected as we experienced continued inflationary pressures in Fort Berthold.
- Cash operating expenses increased to $11.64/BOE compared to $8.42/BOE in 2010. We had higher than expected power costs along with increased repairs and maintenance and well servicing as favorable weather facilitated these activities.
- Funds flow decreased to $156.7 million from $162.6 million in 2010 due to stronger oil production and prices, which were offset by lower natural gas production and prices during the quarter.
- We realized a net loss of $299.4 million compared to net income of $64.5 million in 2010. The majority of the net loss is due to lower natural gas prices which resulted in asset impairments of $327.4 million, including an impairment reversal of $10.1 million. In addition, forward crude oil prices increased during the quarter which resulted in a $108.9 million non-cash mark-to-market loss on our crude oil derivative contracts.

- Cash G&A expenses decreased to $3.05/BOE from $3.48/BOE in 2010. The decrease of $0.43/BOE was mainly due to lower charges on our long-term incentive plans given our lower share price at the end of 2011. Our non-cash G&A also decreased by $0.79/BOE due to the IFRS accounting treatment in 2010 of our predecessor rights incentive plan.
- Dividends per share remained flat at $0.18 per month however our adjusted payout ratio increased in 2011 mainly due to high capital spending levels.

The following tables provide an analysis of key financial and operating results for the three months ended December 31, 2011 and 2010.

(CDN$ millions, except per share amounts)	Three Months Ended December 31, 2011	Three Months Ended December 31, 2010
Financial		
Funds flow[1]	$ 156.7	$ 162.6
Dividends to shareholders	97.7	96.4
Net Income/(loss)	(299.4)	64.5
Capital spending and office	347.8	227.9
Financial per Weighted Average Shares Outstanding		
Funds flow[1]	$ 0.87	$ 0.92
Dividends to shareholders	0.54	0.54
Net Income/(loss)	(1.66)	0.37
Weighted average number of shares outstanding (thousands)	180,845	176,648
Payout ratio[3]	62%	59%
Adjusted payout ratio[3]	284%	234%
Average Daily Production	77,221	80,114
Selected Financial Results per BOE[2]		
Oil & Gas Sales[4]	$ 50.29	$ 42.49
Royalties	(9.62)	(6.20)
Commodity derivative instruments	(1.54)	1.02
Operating costs	(11.64)	(8.42)
General and administrative	(3.05)	(3.48)
Interest and other expenses	(1.70)	(2.95)
Taxes	(0.68)	(0.40)
Funds flow[1]	$ 22.06	$ 22.06
Average Benchmark Pricing		
WTI crude oil (US$/bbl)	$ 94.06	$ 85.17
WTI crude oil: CDN$ equivalent (CDN$/bbl)	95.98	86.03
AECO natural gas – monthly index (CDN$/Mcf)	3.47	3.58
AECO natural gas – daily index (CDN$/Mcf)	3.17	3.62
NYMEX natural gas – monthly NX3 index (US$/Mcf)	3.61	3.81
NYMEX natural gas – monthly NX3 index: CDN$ equivalent (CDN$/Mcf)	3.54	3.85
US/CDN exchange rate	0.98	0.99

(1) See "Non-GAAP Measures" in this MD&A.
(2) Non-cash amounts have been excluded.
(3) Payout ratio is calculated as cash dividends to shareholders divided by funds flow. Adjusted payout ratio is calculated as the sum of cash dividends to shareholders plus capital and office expenditures divided by funds flow. See "Non-GAAP Measures" above.
(4) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

SELECTED QUARTERLY CANADIAN AND U.S. FINANCIAL RESULTS

(CDN$ millions, except per unit amounts)	Three months ended December 31, 2011 Canada	U.S.	Total	Three months ended December 31, 2010 Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	19,726	11,989	31,715	18,930	11,438	30,368
Natural gas liquids (bbls/day)	3,201	55	3,256	4,027	–	4,027
Natural gas (Mcf/day)	218,176	35,324	253,500	244,510	29,804	274,314
Total daily sales (BOE/day)	59,290	17,931	77,221	63,709	16,405	80,114
Pricing(1)						
Crude oil (per bbl)	$ 86.17	$ 89.84	$ 87.56	$ 71.22	$ 73.78	$ 72.18
Natural gas liquids (per bbl)	68.83	38.31	68.32	53.66	–	53.66
Natural gas (per Mcf)	3.13	5.11	3.41	3.47	4.94	3.63
Capital Expenditures						
Capital spending and office	$ 132.0	$ 215.8	$ 347.8	$ 128.9	$ 99.0	$ 227.9
Acquisitions of oil and gas properties	21.5	23.8	45.3	4.5	518.4	522.9
Dispositions of oil and gas properties	(1.1)	(2.0)	(3.1)	(537.9)	–	(537.9)
Revenues						
Oil and gas sales(1)	$ 240.9	$ 116.4	$ 357.3	$ 222.0	$ 91.2	$ 313.2
Royalties(2)	(39.0)	(29.3)	(68.3)	(23.8)	(21.9)	(45.7)
Commodity derivative instruments gain/(loss)	(119.9)	–	(119.9)	(46.1)	–	(46.1)
Expenses						
Operating	$ 72.1	$ 10.9	$ 83.0	$ 55.3	$ 5.5	$ 60.8
General and administrative	20.6	3.8	24.4	31.6	2.8	34.4
Depletion, depreciation and amortization	89.8	31.1	120.9	94.3	17.0	111.3
Impairments/(reversals)	337.4	(10.1)	327.3	116.7	11.7	128.4
Current tax expense/(recovery)	0.6	4.3	4.9	16.6	(13.6)	3.0

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) U.S. Royalties include U.S. state production tax.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with IFRS 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.

Reserves

The process of estimating reserves is critical to several accounting estimates. It 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 gas prices, operating costs and royalty burdens change. Reserve estimates impact net income through depletion, the determination of decommissioning liabilities and the application of impairment tests. Revisions or changes in reserve estimates can have either a positive or a negative impact on net income.

Commodity Prices

Management's estimates of future crude oil and natural gas prices are critical as these prices are used to determine the carrying amount of PP&E, assess impairment and determine the change in fair value of financial contracts. Management's estimates of prices are based on the price forecast from our reserve engineers and the current forward market.

Decommissioning Liability

Management calculates the decommissioning liability 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 amortized over its useful life. There are uncertainties related to decommissioning liabilities 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, reserve estimates, costs and technology.

Business Combinations

Management makes various assumptions in determining the fair values 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 estimate (a) oil and gas reserves in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and (b) future prices of oil and 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 IFRS ACCOUNTING AND RELATED PRONOUNCEMENTS

Refer to Note 3 in our Financial Statements for a detailed listing of Standards and Interpretations that were issued but not yet effective at December 31, 2011.

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, NGLs, and natural gas production. These prices have fluctuated widely in response to a variety of factors including global and domestic demand, weather conditions, the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American natural gas, political stability, transportation facilities, the price and availability of alternative fuels and government regulations.

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. Refer to the "Price Risk Management" section for further details on our price risk management program.

Oil and Gas Reserves and Resources Risk

The value of our company is based on, among other things, the underlying value of the 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 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 reserve or resource write-downs.

Each year, independent reserves engineers evaluate a significant portion of our proved and probable reserves as well as the resources attributable to a significant portion of our undeveloped land.

Independent reserve engineers evaluated 86% of the total proved plus probable value (discounted at 10%) of our year-end reserves. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated the majority of our Canadian reserves as well as the reserves associated with our western U.S. assets and reviewed the internal evaluation completed by Enerplus on the remaining portion. The evaluation of our contingent *resources assocated with our leases at Fort Berthold was conducted by Enerplus and audited by McDaniel. Haas Petroleum Engineering Services, Inc. ("Haas") evaluated 100% of our Marcellus shale gas assets in the U.S. and provided both the reserves and contingent resource estimates. The contingent resource assessments associated with our waterflood properties were completed by Enerplus.*

To ensure comparability, all of the independent reserve engineering firms utilized McDaniel's forecast and constant price and cost assumptions as of December 31, 2011 and evaluated our reserves in accordance with NI 51-101.

The Reserves Committee of the Board of Directors has reviewed and approved the reserve and resource reports of the independent evaluators.

Access to Capital Markets

Our access to capital has allowed us to fund a portion of our acquisitions and development capital program through equity and debt. 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.

We are listed on the Toronto and New York stock exchanges and maintain an active investor relations program. We provide continuous disclosure and maintain complete public filings and expect to maintain our eligibility to file a short form prospectus under applicable Canadian securities law.

Access to Transportation Capacity

Market access for crude oil and natural gas production in Canada and the United States is dependent on our ability to obtain transportation capacity on third party pipelines. Newer resource plays, such as the North Dakota Bakken and the Marcellus shale gas, generally experience a sharp increase in the amount of production being produced in the area which could exceed the existing capacity of the gathering and pipeline infrastructure. While third party pipelines generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of pipeline capacity. There are occasionally operational reasons for curtailing transportation capacity. Accordingly, there can be periods where transportation capacity is insufficient to accommodate all of the production from a given region, causing added expense and/or volume curtailments for all shippers.

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 this risk by contracting for firm transportation capacity or using other means of transportation, including rail and truck.

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 a given 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 in our U.S. Bakken play that will secure some of our drilling and fracturing services into 2013, access to field services and supplies in other areas of our business will continue to be subject to market availability.

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. In addition, although we maintain good working relationships with our industry partners, disputes may arise from time to time with respect to ownership of rights of certain properties or resources.

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 are subject to a broad range of regulatory requirements that continue to increase both within Canada and the United States.

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 with the regulations to be issued with those of the United States. Accordingly, while we continue to prepare to meet the potential requirements, the actual cost impact and its materiality to our business remains uncertain.

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 are approved by the Board of Directors and where appropriate, independent reserve engineer evaluations are obtained.

Health, Safety and Environmental Risk ("HSE")

Health, safety and environmental risks influence the workforce, operating costs and the establishment of regulatory standards. Certain government and regulatory agencies in Canada and the United States have begun investigating the potential risks associated with hydraulic fracturing. We expect regulatory frameworks will be amended or continue to emerge in this regard. The impact of such changes on our business could increase our cost of compliance and the risk of litigation and environmental liability.

Enerplus has established a Safety and Social Responsibility ("S&SR") team that develops standards and systems to manage health, safety, environment, regulatory compliance and stakeholder engagement for the organization.

These management systems include:

- *leadership obligations and setting goals and objectives*
- *training needs and competency standards*
- *measuring, reporting and analyzing performance*
- *developing critical standards, procedures and guidelines*
- *audits, inspections and compliance monitoring*
- *emergency response planning*
- *identifying and managing environmental liabilities associated with our existing asset base and potential acquisitions*
- *integrity management programs for pipelines and facilities*

We carry insurance to cover a portion of our property losses, liability and potential losses from business interruption.

The actions of the S&SR team are driven in part by a steering committee which is comprised of executives and senior management. All S&SR risks are reviewed regularly by the S&SR committee which is comprised of members of the Board of Directors.

Counterparty and Joint Venture Credit Exposure

The low natural gas price environment increases 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.

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. 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.

Foreign Currency Exposure

We have exposure to fluctuations in foreign currency as most of our senior unsecured 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 as the Canadian dollar weakens relative to the U.S. dollar.

We have hedged our foreign currency exposure on our US$175 million, US$54 million and a portion of our US$225 million senior notes using financial swaps that convert the U.S. denominated debt to Canadian dollar debt. In addition, we have hedged the U.S. dollar interest obligation on our US$175 million notes. We have not entered into any other foreign currency derivatives with respect to our oil and gas sales or our U.S. operations.

Interest Rate Exposure

We have exposure to movements in interest rates and credit markets as changing interest rates affect our borrowing costs and the share price of yield-based 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 46% of our debt through our senior unsecured notes and interest rate swaps.

Changes in Tax and Other Laws

Changes in tax and other laws may adversely affect us and our shareholders. Income tax laws, other laws or government incentive programs relating to the oil and gas industry may be changed or interpreted in a manner that adversely affects the Company and its shareholders. Tax authorities having jurisdiction over us (whether as a result of our operations or financing) may change or interpret applicable tax laws, tax treaties or administrative positions in a manner which is detrimental to us or may disagree with how we calculate our income for tax purposes.

We monitor government correspondence 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.

Cash Flow Sensitivity

The sensitivities below reflect all commodity contracts listed in Note 15 and are based on forward markets as at February 10, 2012. 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 2012 Funds Flow per Share(1)**
Change of $0.50 per Mcf in the price of AECO natural gas	$ 0.14
Change of US$5.00 per barrel in the price of WTI crude oil	$ 0.13
Change of 1,000 BOE/day in production	$ 0.03
Change of $0.01 in the US$/CDN$ exchange rate	$ 0.05
Change of 1% in interest rate	$ 0.02

(1) Assumes 199,818,000 weighted average shares outstanding.

The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any inter-relationship among the factors.

2012 GUIDANCE

A summary of our 2012 guidance is below. This guidance does not include any potential acquisition or divestments.

Summary of 2012 Expectations	Target
Average annual production	83,000 BOE/day
Exit rate production	88,000 BOE/day
Capital spending	$800 million
Marcellus carry commitment spending	$37 million
Production mix (volumes)	50% natural gas, 50% crude oil and liquids
Average royalty rate (% of gross sales, net of transportation)	21%
Operating costs	$10.40/BOE
G&A expenses	$3.55/BOE
Average interest and financing costs	6%

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at December 31, 2011, 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 October 1, 2011 and ended December 31, 2011 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 Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

FORWARD-LOOKING INFORMATION AND STATEMENTS

*This MD&A contains certain forward-looking information and forward-looking statements within the meaning of applicable securities laws ("**forward-looking information**"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected 2012 average and exit production volumes and the anticipated production mix; the results from our Fort Berthold drilling program and the timing of related production; future oil and natural gas prices and our commodity risk management programs; future royalty rates on our production; anticipated cash and non-cash G&A and financing expenses; operating costs; capital spending levels in 2012 and its impact on our production levels; the amount of our future abandonment and reclamation costs and decommissioning liabilities; our 2012 U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and debt-to-funds-flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; the amount and timing of future cash dividends that we may pay to our shareholders; our transition to IFRS and the impact of that change on our financial results and disclosure.*

The forward-looking information contained in this MD&A reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and resource volumes; commodity price and cost assumptions; the *continued availability of adequate debt and/or equity financing and funds flow to fund our capital and operating requirements and dividend payments as needed; the availability of third party services; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.*

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: changes in commodity prices; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties, increased debt levels or debt service requirements; inaccurate estimation of our oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in this MD&A for the year ended December 31, 2011 and under "Risk Factors" in our Annual Information Form for the year ended December 31, 2011 which will be available in mid-March 2012 on our website at www.enerplus.com and under our SEDAR profile at www.sedar.com. Additionally, the Annual Information Form will form part of our Form 40-F that will be filed in mid-March with the SEC and will be available on EDGAR at www.sec.gov.

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.