enerPLUS

SECOND QUARTER REPORT

SIX MONTHS ENDED JUNE 30, 2011

SELECTED FINANCIAL RESULTS	Three months ended June 30, 2011	Three months ended June 30, 2010[1]	Six months ended June 30, 2011	Six months ended June 30, 2010[1]
Financial (000's)				
Funds Flow[2]	**$ 132,441**	$ 174,753	**$ 293,665**	$ 373,035
Dividends to Shareholders	**97,077**	95,909	**193,763**	191,621
Net Income/(Loss)	**267,982**	76,502	**297,531**	(107,520)
Debt Outstanding – net of cash	**460,087**	697,817	**460,087**	697,817
Capital Spending	**145,165**	88,395	**319,609**	182,556
Property and Land Acquisitions	**94,415**	310,114	**142,633**	349,747
Divestments	**571,096**	181,238	**630,788**	182,776
Financial per Weighted Average Shares Outstanding				
Funds Flow[2]	**$ 0.74**	$ 0.99	**$ 1.64**	$ 2.13
Dividends	**0.54**	0.55	**1.08**	1.09
Net Income/(Loss)	**1.50**	0.44	**1.66**	(0.61)
Weighted Average Number of Shares Outstanding	**179,583**	175,705	**179,209**	175,099
Debt to Trailing 12 Month Funds Flow	**0.7x**	0.9x[5]	**0.7x**	0.9x[5]
Selected Financial Results per BOE[3]				
Oil & Gas Sales[4]	**$ 51.62**	$ 41.18	**$ 49.28**	$ 44.39
Royalties	**(9.07)**	(7.35)	**(8.85)**	(7.96)
Commodity Derivative Instruments	**(3.03)**	2.23	**(1.30)**	1.38
Operating Costs	**(9.86)**	(10.09)	**(9.37)**	(10.03)
General and Administrative	**(3.16)**	(2.18)	**(3.21)**	(2.46)
Interest and Other Expenses	**(0.89)**	(1.12)	**(1.82)**	(0.99)
Taxes	**(6.30)**	(0.05)	**(3.22)**	(0.03)
Funds Flow[2]	**$ 19.31**	$ 22.62	**$ 21.51**	$ 24.30

SELECTED OPERATING RESULTS	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Average Daily Production				
Natural gas (Mcf/day)	**255,665**	296,566	**253,584**	297,737
Crude oil (bbls/day)	**29,330**	31,559	**29,831**	31,268
NGLs (bbls/day)	**3,442**	3,922	**3,337**	3,924
Total (BOE/day)	**75,383**	84,909	**75,433**	84,815
% Natural gas	**57%**	58%	**56%**	59%
Average Selling Price[4]				
Natural gas (per Mcf)	**$ 3.86**	$ 3.78	**$ 3.88**	$ 4.44
Crude oil (per bbl)	**90.92**	68.72	**84.23**	71.25
NGLs (per bbl)	**66.20**	47.55	**63.35**	52.49
US$/CDN$ exchange rate	**1.03**	0.97	**1.02**	0.97
Net Wells drilled	**14**	19	**40**	158

(1) 2010 comparative amounts have been restated and are presented in accordance with International Financial Reporting Standards ("IFRS"). In addition, 2010 comparatives represent the results of Enerplus Resources Fund which converted into Enerplus Corporation on January 1, 2011.
(2) See "Non-GAAP Measures" in the Management's Discussion and Analysis of Enerplus Corporation dated August 4, 2011.
(3) Non-cash amounts have been excluded.
(4) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(5) The 12 months trailing funds flow for June 30, 2010, includes funds flow for July through December 2009 which was prepared following previous Canadian GAAP.

Share Trading Summary For the three months ended June 30, 2011	**CDN* – ERF** (CDN$)	**U.S.** – ERF** (US$)
High	$ 31.54	$ 32.86
Low	$ 28.82	$ 29.61
Close	$ 30.45	$ 31.60

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

2011 Cash Dividends Per Share Payment Month	**CDN$**	**US$***
First Quarter Total	**$ 0.54**	**$ 0.55**
April	$ 0.18	$ 0.19
May	0.18	0.18
June	0.18	0.18
Second Quarter Total	**$ 0.54**	**$ 0.55**
Total Year-to-Date	**$ 1.08**	**$ 1.10**

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

This interim report, including the President's Message and management's discussion and analysis ("MD&A") contained herein, contains certain forward-looking information and statements. We refer you to the end of the management's discussion and analysis under "Forward-Looking Information and Statements" for our disclaimers on forward-looking information and statements, which apply to all other portions of this interim report. For information on the use of the term "BOE" see the introductory paragraph under the MD&A section in this interim report and the disclaimer at the end of the accompanying MD&A. For information regarding the primary contingencies which currently prevent the classification of our disclosed "contingent resources" associated with our Marcellus shale gas assets as reserves and the positive and negative factors relevant to the "contingent resource" estimate, see our Annual Information Form for the year ended December 31, 2010 (and corresponding Form 40-F), a copy of which is available on our SEDAR profile at www.sedar.com and a copy of the Form 40-F, which is available on our EDGAR profile at www.sec.gov.

ASSET PORTFOLIO

Our efforts to focus our operations and improve our financial flexibility continued during the quarter with the sale of a portion of our interest in the Marcellus. We sold approximately 45% of our acreage position in Pennsylvania, Maryland and West Virginia for approximately $568 million, capturing a pre-tax gain of $272 million for our shareholders on this sale. We have retained a significant land position consisting of 110,000 net acres in the Marcellus subsequent to the sale, 60% of which is operated. Our non-operated position includes approximately 45,000 net acres concentrated in the prolific Northeast area of Pennsylvania whereas our 65,000 net operated acres are located in West Virginia and Maryland. The independent best estimate of contingent resources associated with our leases is 2.3 Tcfe and 92 Bcfe of proved plus probable natural gas reserves as of December 31, 2010. The sale included 24.5 Bcfe of proved plus probable reserves. Proceeds from the sale were used to reduce our outstanding bank debt, leaving our $1 billion credit facility virtually undrawn at the end of the quarter and available to support our plans going forward.

Through the first half and into the third quarter of 2011 we continued to add to our undeveloped land inventory in emerging resource plays in Canada. We've acquired approximately 38,000 net acres in the liquids-rich Duvernay shale play and 14,000 net acres in two emerging oil prospects where we believe there to be meaningful potential. In addition, we've added over 9,000 net acres of Montney prospective lands in the Cameron area of British Columbia, bringing our total Montney undeveloped land position to approximately 28,000 net acres in this area. In total, we've spent approximately $75 million year-to-date. We expect to acquire seismic and drill a number of pilot wells to evaluate the potential of these lands in late 2011 or early 2012. We now hold a number of significant land positions in strategic resource plays which are expected to provide us with opportunities to grow production over the longer term.

PRODUCTION AND CAPITAL SPENDING SUMMARY

Extremely wet weather conditions in key producing regions across Western Canada and the U.S. presented challenges for many oil and gas producers during the second quarter of 2011, including Enerplus. Access to our leases in Saskatchewan and North Dakota was limited due to flooding and road bans which impacted our ability to move rigs and equipment and, in some areas, our ability to truck oil. These weather conditions delayed the execution of our drilling program by one to two months in these areas. However, strong performance in our base production resulted in an average daily production of 75,383 BOE/day during the quarter, essentially unchanged compared to the first quarter.

We invested $145 million of capital during the quarter drilling 14.1 net wells. Approximately 60% of our spending was directed to oil projects, primarily in the Bakken and 33% invested in the Marcellus. Our non-operated partners continued to be active in the Deep Basin area of Alberta and at Taylorton in southeast Saskatchewan. Field conditions have begun to improve in July and we are ramping up activities with four operated rigs now running in North Dakota at Fort Berthold and are building to four operated rigs in Canada focused mainly on our waterflood properties. We anticipate bringing on over 60 net wells during the second half of the year as capital spending and drilling activity increases. Production volumes are expected to build throughout the remainder of the year, with the most significant increases anticipated late in the third quarter and into the fourth quarter.

	Three months ended June 30, 2011		Six months ended June 30, 2011	
Play Type	Average Production Volumes	Capital Spending ($ millions)	Average Production Volumes	Capital Spending ($ millions)
Bakken/Tight Oil (BOE/day)	12,724	67	13,197	135
Crude Oil Waterfloods (BOE/day)	13,315	19	13,379	48
Conventional Oil (BOE/day)	6,075	1	6,269	4
Total Oil (BOE/day)	32,114	87	32,845	187
Marcellus Shale Gas (Mcfe/day)	21,867	47	21,571	89
Other Natural Gas (Mcfe/day)	237,746	11	233,959	44
Total Gas (Mcfe/day)	259,613	58	255,530	133
Company Total	75,383	145	75,433	320

NET DRILLING ACTIVITY – for the three months ended June 30, 2011

Play Type	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in*	Wells On-stream	Dry & Abandoned Wells
Bakken/Tight Oil	7.6	–	7.6	4.6	3.0	–
Crude Oil Waterfloods	–	–	–	–	–	–
Conventional Oil	1.5	0.1	1.6	1.6	–	–
Total Oil	**9.1**	**0.1**	**9.2**	**6.2**	**3.0**	**–**
Marcellus Shale Gas	4.7	–	4.7	4.7	–	–
Other Natural Gas	0.2	–	0.2	0.2	–	–
Total Gas	**4.9**	**–**	**4.9**	**4.9**	**–**	**–**
Company Total	**14.0**	**0.1**	**14.1**	**11.1**	**3.0**	**–**

* Pending potential completion/tie-in or abandonment and on-stream wells measured as at June 30, 2011

Bakken/Tight Oil

As a result of the unusually wet weather conditions in the Williston Basin, we experienced a second consecutive quarter of lower than anticipated activity in our Bakken/tight oil resource play. We managed to keep two rigs working in Fort Berthold, North Dakota and two rigs working in Sleeping Giant, Montana throughout the quarter where we drilled 6 net operated horizontal wells and brought 2.8 net wells on-stream during the quarter. We also participated in the drilling of 1.6 net wells at Taylorton, Saskatchewan. Production volumes for the quarter averaged approximately 12,700 BOE/day, down 900 BOE/day from the first quarter due to weather and timing delays.

At Fort Berthold, we drilled one long and three short Bakken horizontal wells during the quarter and completed and brought on a short Three Forks well. We began drilling a long Three Forks lateral well during the quarter and anticipate testing the well during the third quarter.

We currently have four rigs working at Fort Berthold and expect to maintain this rig count through the remainder of 2011. Infrastructure and gathering system build continues to proceed and we expect to have a majority of our wells tied in by the end of the third quarter, reducing our reliance on trucking. Production volumes are also expected to increase by approximately 10% due to the associated natural gas volumes which will be captured once the wells are tied into the gathering system. We expect to drill 26 horizontal wells at Fort Berthold during the remainder of the year, targeting both the Bakken and the Three Forks formations and plan to complete and tie-in 22 wells. We have permits in place for all of our 2011 wells and are currently working to secure 2012 and 2013 drilling permits. Our 2011 plans include testing downspacing to determine optimal well density and as a result, we expect approximately 75% of the wells drilled this year will be short lateral horizontals. Under the full development scenario, approximately 75% of the wells are expected to be long horizontals. With four rigs working and our frac services agreement in place, drilling and completions activity should accelerate and we expect to remain on schedule for the balance of the year, drilling and completing three to four wells per month. We continue to expect to spend approximately $250 million in North Dakota and Montana in 2011.

Waterfloods

Activity during the second quarter was mainly focused on our two enhanced oil recovery projects at Giltedge and Medicine Hat. Our polymer pilot at Giltedge is now fully operational and we are seeing indications that the polymer is moving through the project area. Assessment of oil production performance is expected by year end. At Medicine Hat, we continued to work on facility build-out to support our polymer project and plan to be injecting polymer early in 2012. Despite nominal tie-ins during the quarter, production volumes were unchanged from the first quarter at 13,300 BOE/day, emphasizing the benefits of these low decline properties.

Marcellus

High activity levels in the Marcellus continued through the second quarter of 2011 as our partners drilled wells to retain and develop leases. On our non-operated land, we participated in drilling 59 gross wells (approximately 5.3 net) with the majority of this activity in northeastern Pennsylvania where production rates and expected ultimate recoveries have been generally above our type curve. Although none of the wells drilled during the quarter were completed or tied-in due to wet weather, 1.2 net wells previously drilled were brought on stream during the quarter. There are currently 169 gross wells (12.5 net wells) drilled by our partners that are waiting on completion and/or tie-in. Production volumes during the quarter averaged 21.9 MMcfe/day, slightly above our first quarter average of 21.3 MMcfe/day. Subsequent to the sale, Marcellus production is currently running at approximately 12 MMcf/day.

UPDATING 2011 GUIDANCE

Due to cost increases in some areas and additional opportunities identified in our portfolio combined with our strong financial position subsequent to the Marcellus disposition, we are increasing our capital spending plans for 2011 from $650 million to $770 million. Approximately $60 million is attributed to cost increases due to wet weather, cost overruns on some capital projects and some service cost inflation. We also expect to drill more wells in the Marcellus where activity is focused on the highly economic northeast area of Pennsylvania, in the liquids rich Deep Basin region and also in our oil properties in Canada. Over 85% of our spending will still be allocated to our Bakken, Marcellus and waterflood properties.

With this incremental spending, we expect to recover the production volumes lost due to wet weather as well as the Marcellus disposition, and also expect to see increased production volumes in 2012. As a result of the Marcellus disposition (900 BOE/day annual average production, 3,800 BOE/day of exit production) along with capital and production delays caused by weather during the first half of the year (800 BOE/day impact on annual average production), we expect our annual production will now average between 76,000 – 78,000 BOE/day versus our original expectation of 78,000 – 80,000 BOE/day. However, with the additional capital spending and reallocation for the remainder of 2011, we expect to maintain our exit production in the range of 81,000 – 84,000 BOE/day.

With regard to 2012, we are evaluating opportunities within our portfolio and the potential to increase spending and production volumes beyond our original guidance issued earlier this year. We expect to provide greater clarity on our 2012 plans in the fourth quarter.

2011 Estimates		
Capital Expenditures ($ millions)		
Original Capital Expenditure Estimate	$	650
Capital Reduction Due to Marcellus Disposition	$	(50)
Increased Spending	$	170
Revised Capital Expenditure Estimate	$	770
Revised Capital Expenditures By Resource Play		
Bakken/Tight Oil	$	325
Waterfloods	$	145
Marcellus	$	195
Deep Basin	$	55
% of Total		94%
Original Annual Average Production Estimate (BOE/day)		78,000 – 80,000
Oil & Liquids Weighting		47%
Less Marcellus Production Sold & Weather Impacts (BOE/day)		(1,700)
Revised Annual Average Production (BOE/day)		76,000 – 78,000
Oil & Liquids Weighting		45%
Original Exit Production Estimate (BOE/day)		80,000 – 84,000
Less Marcellus Production Sold (BOE/day)		(3,800)
Revised Exit Production Estimate (BOE/day)		81,000 – 84,000
Oil & Liquids Weighting		47%

ADDITIONS TO THE BOARD OF DIRECTORS

We are pleased to announce that Ms. Sue MacKenzie and Mr. David Barr joined the board of directors of Enerplus effective July 1, 2011. Ms. MacKenzie has over 25 years of energy sector experience, having served as Chief Operating Officer with Oilsands Quest Inc. and Vice-President of Human Resources and Vice President of In Situ Development and Operations for Petro-Canada. Mr. Barr has 36 years of experience in the oil and gas industry, and is President and Chief Executive Officer of Logan International Inc. He was formerly Chairman of the Board of Logan International. He also spent close to 20 years with Baker Hughes in various executive roles, including Group President of numerous divisions and President of Baker Atlas.

OUTLOOK

The unusual weather experienced during the first half of 2011 has presented a number of operational challenges for Enerplus. However, through the hard work and dedication of our employees, particularly in the field, we were successful in mitigating any significant impacts to our business and maintaining our production volumes at similar levels to the first quarter. We have once again delivered a significant gain to shareholders with the Marcellus sale and increased our financial strength and ability to deliver on our growth plans. The second half of 2011 is expected to be very active due to the increase in capital spending and the number of wells we plan to drill and tie-in. We will be focused on executing our capital program and achieving our production targets through the remainder of the year.

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Corporation

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

The following MD&A of financial results is dated August 4, 2011 and is to be read in conjunction with:

- the audited consolidated financial statements of Enerplus Resources Fund (the "Fund") as predecessor to Enerplus Corporation ("Enerplus" or the "Company"), as at and for the years ended December 31, 2010 and 2009; and
- the unaudited interim consolidated financial statements of Enerplus as at and for the three and six months ended June 30, 2011 and 2010, the "Interim Financial Statements".

On January 1, 2011, 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 16 of the Interim Financial Statements for more information. All references to Notes in this MD&A are to the note to our Interim Financial Statements.

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

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 our disclaimer.

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 liabilities settled. 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:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2011**	2010	**2011**	2010
Cash flow from operating activities	**$ 163,323**	$ 164,184	**$ 295,726**	$ 350,813
Decommissioning liabilities settled	**3,961**	3,590	**8,171**	7,881
Changes in non-cash operating working capital	**(34,843)**	6,979	**(10,232)**	14,341
Funds Flow	**$ 132,441**	$ 174,753	**$ 293,665**	$ 373,035

"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 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

During the second quarter of 2011 our operations were impacted by unusually wet weather across most of the areas in which we operate. Production for the quarter was 75,383 BOE/day, lower than expected as our Fort Berthold and Sleeping Giant production was impacted by wet conditions that restricted our ability to tie-in new wells and haul existing production to sales points. Our capital spending for the second quarter was $145.2 million, which was also lower than expected as we were unable to move rigs and access leases in many areas. Operating costs of $67.5 million ($9.84/BOE) and general and administrative expenses of $25.0 million ($3.64/BOE) during the quarter were marginally higher than anticipated on a per BOE basis mainly due to lower production.

On June 28, 2011 we closed the sale of a portion of our Marcellus interests in Pennsylvania, Maryland and West Virginia for proceeds of $567.9 million, resulting in a gain of $271.9 million. As a result of the Marcellus disposition we are now expecting U.S. cash taxes of approximately $60 million for 2011 given current spending plans and commodity prices. The Marcellus sale proceeds were used to repay bank indebtedness, leaving our $1 billion bank facility virtually undrawn at quarter end. At June 30, 2011 our trailing twelve month debt to funds flow ratio was 0.7x.

During the quarter we saw continued strength in crude oil prices but natural gas prices remained low. Funds flow totaled $132.4 million, down from $174.8 million in the second quarter of 2010 due to lower production resulting from our 10,400 BOE/day of non-core dispositions throughout 2010 combined with $43 million of current taxes resulting from our Marcellus disposition, although the gain on the transaction is not reported within funds flow.

Given the opportunities in our portfolio and our strong financial position we are increasing our 2011 capital spending guidance to $770 million from $650 million. Based on the timing of this spending we are not expecting to see material associated production until 2012. We are also reducing our 2011 annual average production guidance to 76,000 - 78,000 BOE/day, which reflects the impact of our Marcellus disposition and weather related delays in our capital program. We now expect 2011 exit production in the range of 81,000 to 84,000 BOE/day.

We are not in a position to update our 2012 guidance at this time. We remain on target to achieve the existing 2012 guidance based on the previous capital spend projection, however we are evaluating the opportunity to spend more capital on projects that deliver attractive economics and higher production than originally forecasted. We expect to be in a better position to discuss 2012 capital spending plans in the fourth quarter.

RESULTS OF OPERATIONS

Production

Production in the second quarter averaged 75,383 BOE/day, in-line with the first quarter of 2011 but lower than expected due to wet weather in North Dakota and southern Saskatchewan where flooding shut in some of our leases, impacted our ability to truck oil to sales points, and delayed our planned capital program by one to two months. However, with continuing improvement in the field we are ramping up our capital program and we expect to be able to meet our exit production targets for 2011. We currently have four rigs operating in the Fort Berthold area.

Compared to the second quarter of 2010, production in the second quarter of 2011 decreased 11% or 9,526 BOE/day, which is consistent with our expectations given the disposition of approximately 10,400 BOE/day of non-core production during 2010.

Average daily production volumes for the three and six months ended June 30, 2011 and 2010 are outlined below:

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2011**	**2010**	**% Change**	**2011**	**2010**	**% Change**
Natural gas (Mcf/day)	**255,665**	296,566	(14)%	**253,584**	297,737	(15)%
Crude oil (bbls/day)	**29,330**	31,559	(7)%	**29,831**	31,268	(5)%
Natural gas liquids (bbls/day)	**3,442**	3,922	(12)%	**3,337**	3,924	(15)%
Total daily sales (BOE/day)	**75,383**	84,909	(11)%	**75,433**	84,815	(11)%

Annual Average Production Guidance

- We are revising our 2011 annual average production guidance downwards from 78,000 - 80,000 BOE/day to 76,000 - 78,000 BOE/day. The sale of a portion of our Marcellus acreage had an approximately 900 BOE/day negative impact on our 2011 annual average production. In addition, the unusually wet weather conditions caused delays of approximately 800 BOE/day in our annual average production.

Exit Production Guidance

- We are increasing the low end of our previous 2011 exit production guidance from 80,000 - 84,000 BOE/day to 81,000 - 84,000 BOE/day. We expect production from increased capital spending in our non-operated Marcellus and deep basin properties to offset the 3,800 BOE/day exit shortfall from the Marcellus disposition. Weather related access problems have lingered into July and realistically much of the build towards our exit production targets is expected to occur in the third quarter and the fourth quarter.

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 the three and six months ended June 30, 2011 and 2010. It also compares the benchmark price indices for the same periods.

	Three months ended June 30,			Six months ended June 30,		
Average Selling Price(1)	**2011**	**2010**	**% Change**	**2011**	**2010**	**% Change**
Natural gas (per Mcf)	**$ 3.86**	$ 3.78	2%	**$ 3.88**	$ 4.44	(13)%
Crude oil (per bbl)	**90.92**	68.72	32%	**84.23**	71.25	18%
Natural gas liquids (per bbl)	**66.20**	47.55	39%	**63.35**	52.49	21%
Per BOE	**51.62**	41.18	25%	**49.28**	44.39	11%

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

	Three months ended June 30,			Six months ended June 30,		
Average Benchmark Pricing	**2011**	**2010**	**% Change**	**2011**	**2010**	**% Change**
AECO natural gas – monthly index (CDN$/Mcf)	**$ 3.74**	$ 3.86	(3)%	**$ 3.76**	$ 4.61	(18)%
AECO natural gas – daily index (CDN$/Mcf)	**3.88**	3.90	(1)%	**3.82**	4.42	(14)%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	**4.36**	4.07	7%	**4.25**	4.73	(10)%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	**4.23**	4.20	1%	**4.17**	4.88	(15)%
WTI crude oil (US$/bbl)	**102.56**	78.03	31%	**98.33**	78.37	25%
WTI crude oil CDN$ equivalent (CDN$/bbl)	**99.57**	80.44	24%	**96.40**	80.79	19%
US$/CDN$ exchange rate	**1.03**	0.97	6%	**1.02**	0.97	5%

During the quarter we realized an average price on our natural gas sales of $3.86/Mcf (net of transportation costs), an increase of 2% from $3.78/Mcf for the same period in 2010. For the six months ended June 30, 2011 we realized an average price of $3.88/Mcf (net of transportation costs), a 13% decrease from the same period in 2010. The majority of our natural gas sales are priced with reference to either the monthly or daily AECO indices. However, as we continue to grow gas production in our U.S. Marcellus properties, a larger part of our gas portfolio is exposed to Nymex pricing. The Northeast Marcellus pricing captures a premium to Nymex pricing as it is close to a significant market. This changing portfolio mix is improving our netback relative to the AECO indices.

Our average realized crude oil sales price was $90.92/bbl (net of transportation costs) for the second quarter, a 32% increase from $68.72/bbl during the same period in 2010. Generally, due to our crude oil sales mix, we expect the change in our realized price to fall between the change in the U.S. and Canadian dollar equivalent WTI. However, our second quarter realized price increased more than the benchmark expressed both in Canadian and U.S. dollars. The light sweet differential has improved compared to the same period in 2010 due to supply being curtailed from plant disruptions, wild fires, pipeline breaks and demand increasing out of Europe due to the loss of the light sweet Libyan production. Heavy differentials in the second quarter of 2011 compared to the second quarter of 2010 are wider as supply continues to grow. The improvement in the lighter crude oil differentials is substantially greater than the widening in the heavy differentials and is driving our crude oil netback higher relative to the WTI benchmark.

For the six months ended June 30, 2011 our realized crude oil sales price was $84.23/bbl (net of transportation costs), an 18% increase from $71.25/bbl during the same period in 2010. The increase in our realized price is less than the increase experienced with the benchmark price expressed both in Canadian and U.S. dollars due to the wider heavy and bakken oil price differentials compared to the same period in 2010. Bakken oil differentials increased because of increasing supply compared to take away capacity in the region.

The WTI marketplace in Cushing is becoming over supplied resulting in a significant discount from global oil prices which are generally measured by Brent pricing. Cushing and the rest of the Midwest (PADD II) represent a significant refinery demand location. Historically this area required production to be fed from Canada, the US West as well as the Gulf Coast. As more shale oil production and Canadian oil is coming on stream, Cushing and PADD II are now in an over supplied situation and pipelines delivering crude oil from PADD II to the Gulf Coast are needed to alleviate this situation. This risk will likely exist well into 2013. We have decided to manage this risk by exposing a portion of our portfolio to Brent pricing by taking on a Brent-WTI spread position which effectively indexes a portion of our sales to Brent instead of WTI. We have started adding positions and we now have financial contracts in place for 1,000 BOE/day at Brent less a fixed spread of $14.73/BOE for 2012. See "Price Risk Management" section below.

The Canadian dollar strengthened against the U.S. dollar during the three and six months ended June 30, 2011 compared to the same period in 2010. As most of our crude oil and natural gas is priced in reference to U.S. dollar denominated benchmarks, this movement in the exchange rate decreased the Canadian dollar prices that we would have otherwise realized.

Price Risk Management

We continue to adjust our price risk management program with consideration given to our overall financial position together with 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. During and subsequent to the quarter we continued to add crude oil hedge positions for 2012 and 2013, but did not add any additional natural gas positions due to low forward prices for natural gas. At June 30, 2011 we have no commodity derivative contracts outstanding related to our natural gas production. See Note 15 for a detailed list of our current price risk management positions.

The following is a summary of the financial contracts in place at July 27, 2011 expressed as a percentage of our anticipated net production volumes:

	Crude Oil (US$/bbl)	
	July 1, 2011 – December 31, 2011	**January 1, 2012 – December 31, 2012**
WTI Purchased Puts (floor prices)	–	$ 103.00
%	–	3%
WTI Sold Puts (limiting downside protection)	$ 56.50	$ 65.00
%	12%	3%
WTI Swaps (fixed price)	$ 87.27	$ 98.08
%	62%	33%
WTI Sold Calls (capped price)	–	$ 133.00
%	–	3%
WTI Purchased Calls (repurchasing upside)	$ 101.17	–
%	12%	–
Brent – WTI Spread		$ 14.73
%		3%

Based on weighted average price (before premiums), estimated average annual production of 76,000 to 78,000 BOE/day for 2011, and 83,000 to 85,000 BOE/day for 2012, net of royalties of 20%. We also have a fixed price WTI swap at US$102.95 for 1,000 BOE/day for 2013.

Accounting for Price Risk Management

During the second quarter of 2011 we only had crude oil contracts outstanding as our natural gas contracts expired on March 31, 2011. Our price risk management program generated cash losses of $20.8 million on crude oil contracts during the second quarter, compared to net cash gains of $17.3 million during the second quarter of 2010. For the six months ended June 30, 2011 we experienced cash gains of $13.3 million on natural gas contracts and cash losses of $31.0 million on crude oil contracts, compared to net cash gains of $21.2 million for the same period in 2010. The cash gains in 2011 are due to natural gas contracts which provided floor protection above market prices. The crude oil cash losses in 2011 are a result of crude oil prices rising above our swap positions.

As the forward markets for natural gas and crude oil fluctuate, 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 June 30, 2011 the fair value of our crude oil contracts, net of premiums, represented a loss of $32.3 million which is recorded as a current deferred financial liability on our balance sheet. At December 31, 2010 the fair value of our natural gas and crude oil contracts represented a gain of $12.6 million and a loss of $38.3 million respectively. The change in the fair value of our contracts during the first six months of 2011 resulted in unrealized losses of $12.6 million for natural gas and unrealized gains of $6.1 million for crude oil. 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 share amounts)	**Three months ended June 30, 2011**		**Three months ended June 30, 2010**	
Cash gains/(losses):				
Natural Gas	**$ –**	$ – /Mcf	$ 19.8	$ 0.73/Mcf
Crude Oil	**(20.8)**	$ (7.79)/bbl	(2.5)	$ (0.87)/bbl
Total cash gains/(losses)	**$ (20.8)**	$ (3.03)/BOE	$ 17.3	$ 2.23/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – natural gas	**$ –**	$ – /Mcf	$ (23.8)	$ (0.88)/Mcf
Change in fair value – crude oil	**72.6**	$ 27.20/bbl	39.4	$ 13.72/bbl
Total non-cash gains/(losses)	**$ 72.6**	$ 10.58/BOE	$ 15.6	$ 2.02/BOE
Total gains/(losses)	**$ 51.8**	$ 7.55/BOE	$ 32.9	$ 4.25/BOE

Risk Management Gains/(Losses) ($ millions, except per share amounts)	**Six months ended June 30, 2011**		**Six months ended June 30, 2010**	
Cash gains/(losses):				
Natural Gas	**$ 13.3**	$ 0.29/Mcf	$ 27.8	$ 0.52/Mcf
Crude Oil	**(31.0)**	$ (5.74)/bbl	(6.6)	$ (1.17)/bbl
Total cash gains/(losses)	**$ (17.7)**	$ (1.30)/BOE	$ 21.2	$ 1.38/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – natural gas	**$ (12.6)**	$ (0.27)/Mcf	$ 12.1	$ 0.22/Mcf
Change in fair value – crude oil	**6.0**	$ 1.11/bbl	32.9	$ 5.81/bbl
Total non-cash gains/(losses)	**$ (6.6)**	$ (0.48)/BOE	$ 45.0	$ 2.93/BOE
Total gains/(losses)	**$ (24.3)**	$ (1.78)/BOE	$ 66.2	$ 4.31/BOE

Revenues

Crude oil and natural gas revenues for the three months ended June 30, 2011 were $354.2 million ($359.4 million, net of $5.2 million of transportation costs), an increase of 11% or $35.9 million compared to $318.2 million ($325.2 million, net of $7.0 million of transportation costs) for the same period in 2010. Crude oil and natural gas revenues were higher in the second quarter of 2011 compared to the second quarter of 2010 primarily due to an in increase in crude oil prices partially offset by lower production.

Crude oil and natural gas revenues for the six months ended 2011 were $672.8 million ($683.4 million, net of $10.6 million of transportation costs), a decrease of 1% or $8.6 million compared to $681.5 million ($694.8 million, net of $13.3 million of transportation costs) for the same period in 2010. The changes are due to lower production in 2011 as a result of our 2010 dispositions, partially offset by higher crude oil prices during 2011.

Analysis of Sales Revenue[1] ($ millions)	**Crude Oil**	**NGLs**	**Natural Gas**	**Total**
Quarter ended June, 2010	$ 197.4	$ 17.0	$ 103.8	$ 318.2
Price variance[1]	59.2	5.8	1.7	66.7
Volume variance	(13.9)	(2.1)	(14.7)	(30.7)
Quarter ended June 30, 2011	**$ 242.7**	**$ 20.7**	**$ 90.8**	**$ 354.2**

($ millions)	**Crude Oil**	**NGLs**	**Natural Gas**	**Total**
Year-to-date June 30, 2010	$ 403.3	$ 37.3	$ 240.9	$ 681.5
Price variance[1]	70.2	6.5	(25.8)	50.9
Volume variance	(18.5)	(5.6)	(35.5)	(59.6)
Year-to-date June 30, 2011	**$ 455.0**	**$ 38.2**	**$ 179.6**	**$ 672.8**

(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. For the three and six months ended June 30, 2011 royalties were $62.2 million and $120.8 million respectively, compared to $56.8 million and $122.2 million, for the same periods of 2010. The royalty rate in both 2011 and 2010 was 18%, calculated as a percentage of oil and gas sales, net of transportation costs. We continue to expect a royalty rate of 20% for 2011 as we bring on more Fort Berthold production during the second half of the year which has a higher royalty rate.

Operating Expenses

Operating expenses for the second quarter of 2011 were $67.5 million or $9.84/BOE compared to $75.9 million or $9.96/BOE for the same period in 2010. For the six months ended June 30, 2011 operating expenses were $124.6 million or $9.13/BOE compared to $151.8 million or $9.89/BOE for the same period in 2010. Our 2011 operating costs were higher than expected due to lower production and weather related costs. Compared to 2010, operating costs have decreased during 2011 mainly due to the divestment of higher operating cost properties throughout 2010.

We are maintaining our 2011 operating cost guidance of approximately $9.20/BOE as we are actively working to control costs and offset the impact of lower annual average production.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three and six months ended June 30, 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.

	Three months ended June 30, 2011		
	Crude Oil	**Natural Gas**	**Total**
Average Daily Production	**32,114 BOE/day**	**259,613 Mcfe/day**	**75,383 BOE/day**
Netback[1] **$ per BOE or Mcfe**	**(per BOE)**	**(per Mcfe)**	**(per BOE)**
Revenue[2]	**$ 84.38**	**$ 4.55**	**$ 51.62**
Royalties	**(15.71)**	**(0.69)**	**(9.07)**
Cash operating costs	**(11.80)**	**(1.39)**	**(9.80)**
Netback before hedging	**$ 56.87**	**$ 2.47**	**$ 32.75**
Realized gain/(loss) on commodity derivatives	**(7.10)**	**–**	**(3.03)**
Netback after hedging	**$ 49.77**	**$ 2.47**	**$ 29.72**
Netback before hedging ($ millions)	**$ 166.1**	**$ 58.5**	**$ 224.6**
Netback after hedging ($ millions)	**$ 145.3**	**$ 58.5**	**$ 203.8**

	Three months ended June 30, 2010		
	Crude Oil	Natural Gas	Total
Average Daily Production	35,088 BOE/day	298,928 Mcfe/day	84,909 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 62.77	$ 4.33	$ 41.18
Royalties	(13.67)	(0.48)	(7.35)
Cash operating costs	(12.77)	(1.37)	(10.09)
Netback before hedging	$ 36.33	$ 2.48	$ 23.74
Realized gain/(loss) on commodity derivatives	(0.77)	0.73	2.23
Netback after hedging	$ 35.56	$ 3.21	$ 25.97
Netback before hedging ($ millions)	$ 116.0	$ 67.4	$ 183.4
Netback after hedging ($ millions)	$ 113.5	$ 87.2	$ 200.7

(1) Non-GAAP measure
(2) Net of oil and gas transportation costs

	Six months ended June 30, 2011		
	Crude Oil	Natural Gas	Total
Average Daily Production	**32,845 BOE/day**	**255,530 Mcfe/day**	**75,433 BOE/day**
Netback[1] $ per BOE or Mcfe	**(per BOE)**	**(per Mcfe)**	**(per BOE)**
Revenue[2]	**$ 77.99**	**$ 4.52**	**$ 49.28**
Royalties	**(15.75)**	**(0.59)**	**(8.85)**
Cash operating costs	**(10.70)**	**(1.38)**	**(9.34)**
Netback before hedging	**$ 51.54**	**$ 2.55**	**$ 31.09**
Realized gain/(loss) on commodity derivatives	**(5.22)**	**0.29**	**(1.30)**
Netback after hedging	**$ 46.32**	**$ 2.84**	**$ 29.79**
Netback before hedging ($ millions)	**$ 306.3**	**$ 118.3**	**$ 424.6**
Netback after hedging ($ millions)	**$ 275.3**	**$ 131.6**	**$ 406.9**

	Six months ended June 30, 2010		
	Crude Oil	Natural Gas	Total
Average Daily Production	35,010 BOE/day	298,833 Mcfe/day	84,815 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 64.85	$ 5.00	$ 44.39
Royalties	(14.40)	(0.57)	(7.95)
Cash operating costs	(12.49)	(1.37)	(10.00)
Netback before hedging	$ 37.96	$ 3.06	$ 26.44
Realized gain/(loss) on commodity derivatives	(1.03)	0.51	1.38
Netback after hedging	$ 36.93	$ 3.57	$ 27.82
Netback before hedging ($ millions)	$ 240.6	$ 165.2	$ 405.8
Netback after hedging ($ millions)	$ 234.0	$ 193.0	$ 427.0

(1) Non-GAAP measure
(2) Net of oil and gas transportation costs

Crude oil represented 72% of the total corporate netback before hedging for the first six months of 2011. Crude oil netbacks have increased for the three and six months ended June 30, 2011 due to increased crude oil prices partially offset by higher hedging losses. Natural gas netbacks have decreased in 2011 due to lower natural gas prices and lower hedging gains asour natural gas hedges expired on March 31, 2011. Operating costs have decreased in 2011 as a result of our divestment program during 2010 which included higher operating cost properties.

General and Administrative Expenses ("G&A")

G&A expenses for the three months ended June 30, 2011 were $25.0 million or $3.64/BOE compared to $17.4 million or $2.26/BOE for the same period during 2010. G&A expenses for the six months ended June 30, 2011 totaled $50.7 million or $3.71/BOE compared to $37.7 million or $2.46/BOE for the six months ended June 30, 2010.

Our non cash G&A is higher by $2.7 million for the three months ended June 30, 2011 ($6.9 million for the six months ended June 30, 2011) compared to the same periods in 2010 due to the method of accounting for our predecessor rights incentive plan resulting from our conversion to a corporation under IFRS.

For stock option grants issued in 2011 and beyond we are using the Black Scholes model to calculate the grant date fair value, which is expensed over the vesting period of the options. See Note 14 for further details.

Our cash G&A increased by $6.1 million or 16% for the first six months of 2011 compared to the same period during 2010 due to higher compensation costs and increased estimates associated with our long-term incentive plans resulting from the increase in our share price. On a per BOE basis our cash G&A increased $0.75/BOE or 30% which also reflects lower production levels during 2011 resulting from our 2010 asset divestments.

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

General and Administrative Costs ($ millions)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Cash G&A	**$ 21.7**	$ 16.8	**$ 43.9**	$ 37.8
Stock option plan (non-cash)	**3.3**	0.6	**6.8**	(0.1)
Total G&A	**$ 25.0**	$ 17.4	**$ 50.7**	$ 37.7

(Per BOE)	**2011**	**2010**	**2011**	**2010**
Cash G&A	**$ 3.16**	$ 2.18	**$ 3.21**	$ 2.46
Stock option plan (non-cash)	**0.48**	0.08	**0.50**	–
Total G&A	**$ 3.64**	$ 2.26	**$ 3.71**	$ 2.46

Despite reducing our annual average production guidance we are maintaining our 2011 guidance of $3.45/BOE consisting of $3.00/BOE for cash G&A and $0.45/BOE for non-cash G&A.

Finance Expense

Finance expense includes cash interest costs on our senior notes and bank credit facility. 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"). See Note 11 for further details.

Interest on our senior notes and bank debt for the three and six months ended June 30, 2011 totaled $12.7 million and $24.6 million respectively, compared to $9.9 million and $19.1 million for the same periods in 2010. The increase is primarily due to higher average bank debt outstanding during 2011 and higher drawn and undrawn fees compared to 2010.

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

Finance Expense ($ millions)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Interest on senior notes and bank credit facility	**$ 12.7**	$ 9.9	**$ 24.6**	$ 19.1
Non-cash finance expense	**5.1**	2.5	**7.2**	7.2
Total Finance Expense	**$ 17.8**	$ 12.4	**$ 31.8**	$ 26.3

At June 30, 2011 approximately 80% of our debt was based on fixed interest rates while 20% had floating interest. In comparison, at June 30, 2010 approximately 65% of our debt was based on fixed interest rates and 35% was floating.

Foreign Exchange

We recorded net foreign exchange gains of $4.5 million and $2.9 million for the three and six months ended June 30, 2011 respectively compared to losses of $13.6 million and $3.2 million during the same periods in 2010. On June 19, 2011 we made the second US$35.0 million principal repayment on our US$175.0 million senior notes. 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 similar effect of approximately $18.0 million was recorded upon the June 19, 2010 principal repayment. See Note 12 for further information.

Foreign Exchange ($ millions)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Realized loss/(gain)	**$ 13.0**	$ 16.9	**$ 20.3**	$ 14.4
Unrealized loss/(gain)	**(17.5)**	(3.3)	**(23.2)**	(11.2)
Total Foreign Exchange loss/(gain)	**$ (4.5)**	$ 13.6	**$ (2.9)**	$ 3.2

Exploration & Evaluation Assets

Exploration and Evaluation ("E&E") assets are assets that management has not fully evaluated for technical feasibility and commercial viability. When an asset or area is determined to be technically feasible and commercially viable, the accumulated costs are tested for impairment and then transferred to Property, Plant and Equipment ("PP&E") as Developed and Producing ("D&P") assets.

Approximately $120.5 million of E&E assets were transferred to PP&E as D&P assets during the second quarter of 2011. These transferred assets consisted of $41.7 million of Canadian oil focused E&E assets in the Ratcliffe and Cardium and $78.8 million of U.S. assets, primarily in the Marcellus. There were no impairments recorded in the quarter. See Note 4 for further information.

Capital Investment

Capital spending for the second quarter of 2011 was $145.2 million compared to $88.4 million for the same period in 2010. Wet weather delayed our activities as poor conditions restricted access to leases in both Canada and the U.S. The weather also resulted in capital cost increases including higher trucking charges for moving equipment and hauling fluids as well as drilling rig stand-by charges. Activity during the quarter focused predominantly on our key resource plays with $67.0 million directed towards Bakken/tight oil assets, $19.0 million for crude oil waterfloods and $47.0 million on our Marcellus assets.

Property and land acquisitions for the three and six months ended June 30, 2011 totaled $94.4 million and $142.6 million respectively, compared to $310.1 million and $349.7 million for the same periods in 2010. In the first half of 2011 we spent $59.5 million on the acquisition of undeveloped land in Canada, primarily focused on emerging resource plays which included 27,000 net acres in the Duvernay high liquids shale prospect, 9,000 net acres of 100% working interest lands in two oil prospects and 9,000 net acres of Montney prospective lands in British Columbia. Subsequent to the second quarter we purchased an additional 10,000 net acres in the Duvernay and a further 5,000 net acres in the same oil prospects. In the U.S. we acquired approximately $21.8 million of additional undeveloped lands in the Marcellus area. In addition, we spent US$63.2 million on our Marcellus carry obligation during 2011 resulting in a remaining carry obligation of US$83.9 million at June 30, 2011.

Acquisitions of $310.1 million in the second quarter of 2010 included investments in our Bakken plays in Saskatchewan and North Dakota, the Marcellus natural gas play and the Deep Basin natural gas area in British Columbia, as well as spending on our Marcellus carry obligation.

Our total capital investments for the three and six months ended June 30, 2011 and 2010 are outlined below:

Capital Investment ($ millions)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
E&E assets	**$ 84.7**	$ 40.4	**$ 180.0**	$ 75.9
D&P assets	**60.5**	48.0	**139.6**	106.7
Capital Spending	**145.2**	88.4	**319.6**	182.6
Office Capital	**3.4**	0.7	**5.0**	1.2
Sub-total	**148.6**	89.1	**324.6**	183.8
E&E assets	**92.1**	305.0	**139.6**	336.8
D&P assets	**2.3**	5.1	**3.0**	12.9
Property and Land Acquisitions	**94.4**	310.1	**142.6**	349.7
Property Dispositions	**(571.1)**	(181.3)	**(630.8)**	(182.8)
Total Net Capital Investment	**$ (328.1)**	$ 217.9	**$ (163.5)**	$ 350.7

2011 Capital Spending Guidance

We are increasing our 2011 annual capital spending guidance from $650 million to $770 million. We expect to redeploy the capital originally allocated to the sold Marcellus properties into our non-operated Marcellus properties in the prolific northeastern Pennsylvania area. In addition, we expect to expand our capital program in Canadian oil projects such as Freda Ratcliffe and Pembina as well as our non-operated liquids rich gas programs in the Deep Basin. Approximately $60 million of the increase can be attributed to transitory capital cost increases related to the weather, cost overruns at a few of our delineation projects and inflationary cost increases. Most of the incremental capital spending is expected late in the year, with minimal impact on 2011 production.

Dispositions

During the quarter we disposed of approximately 91,000 net acres of our Marcellus interests for proceeds of $567.9 million (US$580 million). These assets were primarily non-operated acreage in southwest and central Pennsylvania, Garrett County in Maryland and northern West Virginia, as well as some operated interests in the Snowshoe area in Centre County. Under IFRS we recognized a pre-tax gain of $271.9 million on this disposition. Subsequent to this transaction, we have retained approximately 110,000 net acres of Marcellus land comprised of approximately 45,000 net acres with an average 20% non-operated working interest in the prolific northeast area of Pennsylvania along with approximately 65,000 net acres with an average 90% operated working interest in Maryland and West Virginia.

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

DD&A of PP&E is recognized using the unit-of-production method based on proved plus probable reserves. For the three months ended June 30, 2011 DD&A totaled $103.7 million or $15.11/BOE compared to $118.2 million or $15.29/BOE during the same period in 2010. For the six months ended June 30, 2011 DD&A totaled $203.6 million or $14.91/BOE compared to $236.3 million or $15.39/BOE during the same period in 2010. The decrease in DD&A for the three and six months ended June 30, 2011 is primarily due to lower production and the impact of impairments recorded to PP&E assets during the second quarter of 2010.

Impairments

On transition to IFRS, the majority of our goodwill in Canada was allocated to our Canadian natural gas focused Cash Generating Units ("CGUs"). 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 to goodwill first where applicable, with the remainder recorded against the carrying value of the D&P asset.

During the second quarter of 2011 we did not record any D&P or goodwill impairments. During the second quarter of 2010 we recorded D&P asset impairments of $3.4 million and goodwill impairments of $26.9 million. For the six months ended June 30, 2011 we did not record any goodwill impairments however we recorded D&P impairments of $32.4 million. For the six months ended June 30, 2011 we recorded

$287.7 million of goodwill impairments and $40.2 million of D&P impairments. All our impairments in 2011 and 2010 resulted from lower natural gas price forecasts.

Impairments ($ millions)	**Three months ended June 30,**		**Six months ended June 30,**	
	2011	**2010**	**2011**	**2010**
Goodwill impairments	**$ –**	$ 26.9	**$ –**	$ 287.7
D&P impairments	**–**	3.4	**32.4**	40.2
Total Impairments	**$ –**	$ 30.3	**$ 32.4**	$ 327.9

Other Assets

Other assets consist of Enerplus' equity investments in entities involved in the oil and gas industry. For the three months ended June 30, 2011 the change in fair value of these investments represented an unrealized gain of $58.1 million ($50.3 million net of tax), which is recorded in other comprehensive income. The majority of the gain was attributable to the increase in fair value of Enerplus' investment in Laricina Energy Ltd. For the three months ended June 30, 2010 Enerplus recorded an unrealized gain on investments of $7.4 million ($6.3 million net of tax). There were no realized gains or losses on these investments for the three and six months ended June 30, 2011 and 2010.

Decommissioning Liabilities

In connection with our operations, we incur abandonment and reclamation costs related to our assets including 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 liabilities to be $389.0 million at June 30, 2011 compared to $392.7 million at December 31, 2010.

Taxes

For the three months ended June 30, 2011, our total income tax expense was $138.4 million, consisting of $43.2 million of current tax and $95.2 of deferred tax. Our Marcellus disposition significantly increased the income in our U.S. subsidiary and we are now expecting to be cash taxable in 2011. We are expecting approximately $60 million of U.S. cash taxes in 2011 based on current commodity prices and capital spending plans, consisting of $25 million of income tax and $35 million of Alternative Minimum Tax ("AMT"). AMT is creditable against income taxes payable in the future. We expect a nominal amount of U.S. cash taxes in 2012.

Although we became subject to normal Canadian corporate taxes as a result of our conversion to a corporation effective January 1, 2011, we currently do not expect to pay material cash taxes in Canada prior to 2015 as we have sufficient tax pools to offset our anticipated taxable income prior to that time. This estimate may vary depending on numerous factors, including fluctuating commodity prices, changing tax regulations and acquisition and disposition activity.

Net Income

Net income for the second quarter of 2011 was $268.0 million or $1.50 per share compared to $76.5 million or $0.44 per share for the same period in 2010. Net income for the six months ended June 30, 2011 was $297.5 million compared to a net loss of $107.5 million for the same period in 2010. The $405.0 million increase in net income for the six months ended June 30, 2011 compared to the same period in 2010 was due to reduced impairment losses of $295.5 million, an increase in gains on dispositions of $240.3 million, and a reduction in DD&A of $32.7 million. Theses increase to net income were offset by an increase in commodity derivative instrument losses of $90.5 million and an increase in current and deferred income taxes of approximately $81.3 million.

Cash Flow from Operating Activities

Cash flow from operating activities for the three and six months ended June 30, 2011 was $163.3 million ($0.91 per share) and $295.7 million ($1.65 per share) respectively, compared to $164.2 million ($0.93 per share) and $350.8 million ($2.00 per share) for the same periods in 2010. The decrease was primarily due to higher cash losses on financial contracts in 2011 combined with higher current taxes, G&A expenses, and foreign exchange losses. The decrease was offset by a reduction in operating costs and changes in working capital.

Selected Canadian and U.S. Results

The following table provides a geographical analysis of key operating and financial results for the three and six months ended June 30, 2011 and 2010.

	Three months ended June 30, 2011			Three months ended June 30, 2010		
(CDN$ millions, except per share amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Natural gas (Mcf/day)	**225,158**	**30,507**	**255,665**	277,811	18,755	296,566
Crude oil (bbls/day)	**18,934**	**10,396**	**29,330**	23,260	8,299	31,559
Natural gas liquids (bbls/day)	**3,344**	**98**	**3,442**	3,922	–	3,922
Total Average Daily Production (BOE/day)	**59,805**	**15,578**	**75,383**	73,484	11,425	84,909
Pricing(1)						
Natural gas (per Mcf)	**$ 3.69**	**$ 5.12**	**$ 3.86**	$ 3.69	$ 5.11	$ 3.78
Crude oil (per bbl)	**88.79**	**94.79**	**90.92**	68.47	69.41	68.72
Natural gas liquids (per bbl)	**66.37**	**60.41**	**66.20**	47.55	–	47.55
Capital Expenditures						
Capital spending and office capital	**$ 42.2**	**$ 106.4**	**$ 148.6**	$ 45.9	$ 45.4	$ 91.3
Acquisitions	**47.3**	**47.1**	**94.4**	136.2	173.9	310.1
Dispositions	**(3.2)**	**(567.9)**	**(571.1)**	(181.2)	–	(181.2)
Revenues						
Oil and gas sales(1)	**$ 249.8**	**$ 104.4**	**$ 354.2**	$ 257.1	$ 61.1	$ 318.2
Royalties(2)	**(37.5)**	**(24.7)**	**(62.2)**	(42.5)	(14.3)	(56.8)
Commodity derivative instruments gain/(loss)	**51.8**	**–**	**51.8**	32.9	–	32.9
Expenses						
Operating	**$ 58.9**	**$ 8.6**	**$ 67.5**	$ 72.3	$ 3.6	$ 75.9
General and administrative	**23.0**	**2.0**	**25.0**	13.6	3.8	17.4
Depletion, depreciation and amortization	**83.1**	**20.6**	**103.7**	106.1	12.1	118.2
Impairment	**–**	**–**	**–**	30.3	–	30.3
Current income taxes expense/(recovery)	**–**	**43.2**	**43.2**	–	0.4	0.4

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

(CDN$ millions, except per share amounts)	Six months ended June 30, 2011 Canada	U.S.	Total	Six months ended June 30, 2010 Canada	U.S.	Total
Average Daily Production Volumes						
Natural gas (Mcf/day)	**221,287**	**32,297**	**253,584**	280,620	17,117	297,737
Crude oil (bbls/day)	**19,064**	**10,767**	**29,831**	23,596	7,672	31,268
Natural gas liquids (bbls/day)	**3,221**	**116**	**3,337**	3,924	–	3,924
Total Average Daily Production (BOE/day)	**59,167**	**16,266**	**75,433**	74,290	10,525	84,815
Pricing[1]						
Natural gas (per Mcf)	**$ 3.69**	**$ 5.20**	**$ 3.88**	$ 4.35	$ 5.99	$ 4.44
Crude oil (per bbl)	**82.01**	**88.15**	**84.23**	71.15	71.57	71.25
Natural gas liquids (per bbl)	**63.94**	**47.08**	**63.35**	52.49	–	52.49
Capital Expenditures						
Capital spending and office capital	**$ 134.4**	**$ 190.2**	**$ 324.6**	$ 103.7	$ 83.3	$ 187.0
Acquisitions	**59.5**	**83.1**	**142.6**	139.9	209.8	349.7
Dispositions	**(62.9)**	**(567.9)**	**(630.8)**	(182.8)	–	(182.8)
Revenues						
Oil and gas sales[1]	**$ 469.7**	**$ 203.2**	**$ 672.9**	$ 563.5	$ 118.0	$ 681.5
Royalties[2]	**(71.2)**	**(49.6)**	**(120.8)**	(94.5)	(27.7)	(122.2)
Commodity derivative instruments gain/(loss)	**(24.3)**	**–**	**(24.3)**	66.2	–	66.2
Expenses						
Operating	**$ 109.5**	**$ 15.1**	**$ 124.6**	$ 144.6	$ 7.2	$ 151.8
General and administrative	**45.3**	**5.4**	**50.7**	31.5	6.2	37.7
Depletion, depreciation and amortization	**161.9**	**41.7**	**203.6**	212.1	24.2	236.3
Impairment	**32.4**		**32.4**	327.9	–	327.9
Current income taxes expense/(recovery)	**–**	**44.0**	**44.0**	–	0.4	0.4

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

QUARTERLY FINANCIAL INFORMATION

Our 2011 and 2010 results, as presented below, have been prepared in accordance with IFRS. The 2009 results as presented were prepared under previous Canadian GAAP. Our crude oil and natural gas sales declined after the first quarter of 2010 as asset sales during 2010 reduced overall production levels putting downward pressure on oil and gas sales. During the remainder of 2010 and into 2011 lower production was generally offset by rising crude oil prices.

Net income for the second quarter of 2011 included a significant gain on asset sales. The most significant changes to net income in 2010 were goodwill and PP&E impairment expenses. Net income was also affected by fluctuating commodity prices and risk management costs along with the fluctuating Canadian dollar.

QUARTERLY FINANCIAL INFORMATION ($ millions, except per share amounts)	**Oil and Gas Sales[(1)]**	**Net Income/(Loss)**	**Net Income/(Loss) Per Share**	
			Basic	**Diluted**
2011				
Second Quarter	**$ 354.2**	**$ 268.0**	**$ 1.50**	**$ 1.49**
First Quarter	**318.7**	**29.5**	**0.17**	**0.16**
Total	**$ 672.9**	**$ 297.5**	**$ 1.66**	**$ 1.66**
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)
2009 (Canadian GAAP)				
Fourth Quarter	$ 333.3	$ 2.7	$ 0.02	$ 0.02
Third Quarter	292.1	38.2	0.23	0.23
Second Quarter	306.2	(3.6)	(0.02)	(0.02)
First Quarter	301.2	51.8	0.31	0.31
Total	$ 1,232.8	$ 89.1	$ 0.53	$ 0.53

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

Liquidity and Capital Resources

Our $1.0 billion bank credit facility is an unsecured, covenant-based, three-year term agreement maturing June 30, 2013. Drawn fees under the facility range between 200 and 375 basis points over bankers' acceptance rates. We are currently paying 2% over bankers' acceptance rates which have recently been trading around 1% for a combined rate of approximately 3%. Standby fees on the undrawn portion of the facility are based on 25% of the drawn pricing. We have the ability to request an extension of the facility each year or repay the entire balance at the end of the term.

Total debt at June 30, 2011, including the current portion of $44.5 million, was $464.5 million, a decrease of $267.9 million from December 31, 2010 when total debt was $732.4 million. Total debt at June 30, 2011 was comprised of $14.7 million of bank indebtedness and $449.7 million of senior notes. The decrease of $267.9 million was primarily due to the proceeds from the Marcellus disposition which were applied against bank indebtedness. See Note 9 for further details.

We continued to add foreign exchange swaps during and subsequent to the second quarter with respect to the principal repayments on our US$225 million senior notes that are set to mature between June 2017 and June 2021. We have now swapped US$175 million of notional principal at approximately par. The exchange rate was originally $0.88 US$/CDN$ when these U.S. dollar denominated notes were issued in 2009 and, by utilizing these forward swaps we expect to repay the U.S. debt with significantly less Canadian dollars than we originally borrowed.

Our working capital at June 30, 2011, excluding cash and current deferred financial assets and credits, increased by $22.1 million compared to December 31, 2010. This change relates to lower capital spending during the second quarter compared to the fourth quarter of 2010, which decreased our payable balances. We expect to finance our negative working capital with our funds flow and bank indebtedness.

We have continued to maintain a conservative balance sheet as demonstrated below:

Financial Leverage and Coverage	June 30, 2011	December 31, 2010
Long-term debt to funds flow (12 month trailing)(1)	**0.7 x**	1.0 x
Funds flow to interest expense (12 month trailing)(2)	**13.7 x**	17.4 x
Long-term debt to long-term debt plus equity(1)	**11%**	18%

(1) Long-term debt is measured net of cash and includes the current portion of the senior notes.
(2) Interest expense is finance expense excluding non-cash items.

At June 30, 2011, we were in compliance with our debt covenants.

We expect to have adequate liquidity from funds flow and our bank credit facility to fund capital spending and working capital requirements for 2011. We expect our capital spending and dividends to exceed our funds flow in 2011 and 2012, and that our debt-to-funds flow ratio will increase during this time as we continue to invest in earlier stage growth assets where there is a longer lead time to production and funds flow. We anticipate our debt-to-funds flow levels will decrease after 2012 as production and funds flow from our growth plays are realized.

Our payout ratio, which is calculated as dividends divided by funds flow, was 73% for the second quarter of 2011 compared to 55% for the second quarter of 2010. Our adjusted payout ratio, which is calculated as dividends plus capital spending and office capital divided by funds flow, was 185% for the second quarter of 2011, compared to 106% for the same period in 2010. Our adjusted payout ratio increased during 2011 due to higher capital spending levels, which are not generating immediate production or funds flow, as well as lower funds flow due to lower production and cash taxes in the U.S. resulting from our Marcellus disposition. See “Non-GAAP Measures” above.

Dividend Policy

As a corporation 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 the three and six months ended June 30, 2011 we paid $97.1 million and $193.8 million respectively, to our shareholders as dividends. 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.

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.

Shareholders’ Capital

Effective January 1, 2011, pursuant to the Plan of Arrangement, unitholders of the Fund received one common share of Enerplus Corporation in exchange for each trust unit and 0.425 of a common share of Enerplus Corporation for each exchangeable partnership unit of Enerplus Exchangeable Limited Partnership (“EELP”) held. Under IFRS, EELP units and trust unit rights were considered liabilities and were recorded on the consolidated balance sheet 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.

We had 179,988,000 shares outstanding at June 30, 2011 compared to 175,905,000 shares at June 30, 2010. We had 176,946,000 shares outstanding at December 31, 2010.

During the second quarter of 2011, 709,000 shares (2010 – 344,000) were issued pursuant to the Dividend Reinvestment Plan (“DRIP”) and the stock option plan, resulting in $18.3 million (2010 – $7.2 million) of additional equity. For the six months ended June 30, 2011, $34.3 million of additional equity (2010 – $13.9 million) and 1,339,000 shares (2010 – 653,000) were issued pursuant to the DRIP and the stock option plan. For further details see Note 14.

The weighted average basic number of shares outstanding for the six months ended June 30, 2011 was 179,209,000 (2010 – 175,099,000). At July 27, 2011 we had 180,200,000 shares outstanding.

Guidance

Our 2011 average annual and exit production, capital spending and Marcellus carry spending guidance were adjusted during the second quarter as noted below. All other guidance remains unchanged. We expect to update our 2012 guidance in the fourth quarter. This guidance does not include the impact of any future acquisitions or divestments:

Summary of 2011 Expectations	Target	Comments
Average annual production	76,000 – 78,000 BOE/day	Reduced from 78,000 - 80,000 BOE/day
Exit rate 2011 production	81,000 – 84,000 BOE/day	Increased from 80,000 - 84,000 BOE/day
Capital spending	$770 million	Increased from $650 million
Marcellus carry commitment spending	$90 million	Reduced from $116 million
2011 production mix	55% gas, 45% crude oil and liquids	No change
Average royalty rate	20%	No change
Operating costs	$9.20/BOE	No change
G&A costs	$3.45/BOE	No change
Average interest and financing costs	6%	No change
Cash taxes	US$60 million	Continue to expect nominal Canadian cash taxes

INTERNAL CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the period beginning on April 1, 2011 and ending on June 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

RECENT IFRS ACCOUNTING AND RELATED PRONOUNCEMENTS

March 31, 2011 is Enerplus' first reporting period under IFRS. Accounting standards effective for periods beginning on or after January 1, 2010 have been adopted as part of the transition to IFRS.

The following Standards and Interpretations were in issue but not yet effective at June 30, 2011. We are currently evaluating the impact of these standards on our operations and financial position.

- IFRS 9 *Financial Instruments* – The standard is required to be adopted for periods beginning January 1, 2013. Portions of the standard remain in development and the full impact of the standard will not be known until the project is complete.
- IFRS 10 *Consolidated Financial Statements* – The standard is required to be adopted for periods beginning January 1, 2013.
- IFRS 11 *Joint Arrangements* – The standard is required to be adopted for periods beginning January 1, 2013.
- IFRS 12 *Disclosure of Interests in Other Entities* – The standard is required to be adopted for periods beginning January 1, 2013.
- IFRS 13 *Fair Value Measurement* – The standard is required to be adopted for periods beginning January 1, 2013.
- IAS 1 *Presentation of Items of Other Comprehensive Income* – The standard is required to be adopted for periods beginning on or after July 1, 2012.
- IAS 27 *Consolidation and Separate Financial Statements* – The standard is required to be adopted for periods beginning January 1, 2013.
- IAS 28 *Investments in Joint Ventures* – The standard is required to be adopted for periods beginning January 1, 2013.

ADDITIONAL INFORMATION

Additional information relating to Enerplus and its predecessor Enerplus Fund, 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 2011 and 2012 average and exit oil, natural gas and natural gas liquids production volumes and the* *anticipated production mix; future oil and natural gas prices and our commodity risk management programs; anticipated cash and non-cash G&A and financing expenses; operating costs and the expected results of our active efforts to control such costs; transfer of assets from the "exploration and evaluation" to the "property, plant and equipment" category for accounting purposes; capital spending levels in the remainder of 2011 and 2012, the allocation thereof among our assets and resource plays and its impact on our production levels; expectations relating to our partners' drilling activities; expected number of wells to be brought on stream in the second half of 2011; anticipated progress of construction of infrastructure and gathering system at Fort Berthold and associated reduction in reliance on trucking; the amount of future abandonment and reclamation costs and decommissioning liabilities; our 2011 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, financial capacity, liquidity and capital resources to fund development capital spending and working capital requirements; the amount and timing of future cash dividends that we may pay to our shareholders; potential asset dispositions; average 2011 royalty rates; and 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 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 our MD&A for the year ended December 31, 2010 and under "Risk Factors" in our Annual Information Form for the year ended December 31,2010 dated March 11, 2011, which are available on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com and which form part of our Form 40-F filed with the SEC on March 11, 2011 available 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.

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	June 30, 2011	December 31, 2010	January 1, 2010
Assets				
Current Assets				
Cash		**$ 4,376**	$ 8,374	$ 73,558
Accounts receivable		**115,939**	125,928	142,009
Deferred financial assets	15	**2,789**	12,641	20,364
Other current		**55,497**	49,606	5,041
		178,601	196,549	240,972
Exploration and evaluation assets	4	**725,569**	1,545,378	580,184
Property, plant and equipment	5	**4,106,433**	3,440,568	4,420,339
Goodwill	7	**146,820**	151,345	476,998
Deferred financial assets	15	**3,397**	4,631	1,997
Other assets	8	**212,211**	150,710	88,324
Total Assets		**$ 5,373,031**	$ 5,489,181	$ 5,808,814
Liabilities				
Current liabilities				
Accounts payable		**$ 325,597**	$ 350,625	$ 257,519
Dividends payable		**32,403**	32,157	31,871
Current portion of long-term debt	9	**44,451**	45,845	36,631
Deferred financial credits	15	**50,166**	56,637	37,437
		452,617	485,264	363,458
Long-term debt	9	**420,012**	686,560	522,276
Deferred financial credits	15	**36,290**	46,942	54,788
Deferred tax liability		**530,276**	484,785	588,329
Decommissioning liability	10	**389,002**	392,709	385,885
		1,375,580	1,610,996	1,551,278
Exchangeable limited partnership units	14	**–**	44,387	55,812
Trust unit rights incentive plan	14	**–**	20,156	9,074
		–	64,543	64,886
Total Liabilities		**1,828,197**	2,160,803	1,979,622
Equity				
Shareholders' capital	14	**3,410,605**	5,639,380	5,576,763
Contributed surplus	14	**23,383**	3,795	3,795
Retained Earnings/(Accumulated deficit)		**103,768**	(2,314,775)	(1,751,366)
Accumulated other comprehensive income/(loss)		**7,078**	(22)	–
		3,544,834	3,328,378	3,829,192
Total Liabilities & Equity		**$ 5,373,031**	$ 5,489,181	$ 5,808,814

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Income and Comprehensive Income

		Three months ended June 30,		Six months ended June 30,	
(CDN$ thousands) unaudited	Note	2011	2010	2011	2010
Revenues					
Oil and gas sales		**$ 359,427**	$ 325,190	**$ 683,429**	$ 694,830
Royalties		**(62,224)**	(56,808)	**(120,777)**	(122,175)
Commodity derivative instruments gain/(loss)	15	**51,817**	32,865	**(24,310)**	66,213
		349,020	301,247	**538,342**	638,868
Expenses					
Operating		**67,516**	75,882	**124,591**	151,809
General and administrative		**24,981**	17,429	**50,712**	37,745
Transportation		**5,288**	6,989	**10,562**	13,344
Depletion, depreciation, and amortization	5	**103,695**	118,166	**203,596**	236,298
Impairments	7	**–**	30,275	**32,394**	327,858
Foreign exchange	12	**(4,542)**	13,633	**(2,880)**	3,224
Finance expense	11	**17,834**	12,434	**31,841**	26,325
Asset disposition (gain)/loss	6	**(271,910)**	(57,840)	**(298,145)**	(57,840)
Other expense/(income)		**(189)**	(91)	**(596)**	166
		(57,327)	216,877	**152,075**	738,929
Income/(loss) before taxes		**406,347**	84,371	**386,267**	(100,061)
Current tax expense	13	**43,214**	409	**43,996**	409
Deferred income tax expense	13	**95,151**	7,459	**44,740**	7,050
Net Income/(loss)		**$ 267,982**	$ 76,502	**$ 297,531**	$ (107,520)
Other comprehensive income					
Change in fair value of available for sale financial instruments, net of tax	8	**$ 50,270**	$ 6,305	**$ 53,218**	$ 43,286
Change in cumulative translation adjustment		**(14,953)**	39,310	**(46,118)**	12,676
Other comprehensive income, net of tax		**35,317**	45,615	**7,100**	55,962
Total comprehensive income/(loss)		**$ 303,299**	$ 122,117	**$ 304,631**	$ (51,558)
Net income (loss) per share					
Basic		**$ 1.50**	$ 0.44	**$ 1.66**	$ (0.61)
Diluted		**$ 1.49**	$ 0.38	**$ 1.66**	$ (0.66)
Weighted average number of shares outstanding (thousands)	14				
Basic		**179,583**	175,705	**179,209**	175,099
Diluted		**180,085**	177,782	**179,711**	175,368

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Changes in Shareholders' Equity

Six months ended June 30 (CDN$ thousands) unaudited	2011	2010
Shareholders' Capital		
Balance, beginning of year	**$ 5,639,380**	$ 5,576,763
Reclassification of EELP units	**44,387**	–
Reclassification of accumulated deficit	**(2,314,775)**	–
Conversion of EELP units	**–**	21,360
Stock option plan – cash	**9,714**	2,573
Stock option plan – non cash	**7,346**	884
DRIP	**24,553**	11,337
Balance, end of period	**$ 3,410,605**	$ 5,612,917
Contributed Surplus		
Balance, beginning of year	**$ 3,795**	$ 3,795
Reclassification of trust unit rights liability	**20,156**	–
Stock option plan – exercised	**(7,346)**	–
Stock option plan – expensed	**6,778**	–
Balance, end of period	**$ 23,383**	$ 3,795
Retained Earnings/(Accumulated Deficit)		
Balance, beginning of year	**$ (2,314,775)**	$ (1,751,366)
Reclassification to Shareholders' Capital	**2,314,775**	–
Net income/(loss)	**297,531**	(107,520)
Dividends on common shares	**(193,763)**	(191,621)
Balance, end of period	**$ 103,768**	$ (2,050,507)
Accumulated other comprehensive income		
Balance, beginning of year	**$ (22)**	$ –
Change in fair value of available for sale financial instruments, net of tax	**53,218**	43,286
Cumulative translation adjustment	**(46,118)**	12,676
Balance, end of period	**$ 7,078**	$ 55,962
Total equity	**$ 3,544,834**	$ 3,622,167

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Operating Activities				
Net income/(loss)	**$ 267,982**	$ 76,502	**$ 297,531**	$ (107,520)
Non-cash items add/(deduct):				
Depletion, depreciation and amortization	**103,695**	118,166	**203,596**	236,298
Impairments	**–**	30,275	**32,394**	327,858
Change in fair value of derivative instruments	**(87,664)**	(40,937)	**(6,887)**	(64,118)
Deferred income tax	**95,151**	7,459	**44,740**	7,050
Foreign exchange (gain)/loss on U.S. dollar debt	**(1,189)**	20,873	**(13,123)**	5,507
Accretion expense	**3,379**	3,622	**6,794**	7,510
Stock based compensation	**3,295**	612	**6,778**	(65)
Change in fair value of exchangeable limited partnership units	**–**	(1,768)	**–**	746
Amortization of debt transaction costs	**284**	(180)	**569**	(360)
Cross currency interest rate swap principal settlement	**19,418**	17,969	**19,418**	17,969
Asset disposition gain	**(271,910)**	(57,840)	**(298,145)**	(57,840)
	132,441	174,753	**293,665**	373,035
Decommissioning liabilities settled	**(3,961)**	(3,590)	**(8,171)**	(7,881)
Changes in non-cash operating working capital	**34,843**	(6,979)	**10,232**	(14,341)
Cash flow from operating activities	**163,323**	164,184	**295,726**	350,813
Financing Activities				
Issuance of shares	**18,266**	7,179	**34,266**	13,911
Dividends to shareholders	**(97,077)**	(95,909)	**(193,763)**	(191,621)
Increase (decrease) in bank debt	**(353,261)**	170,007	**(220,290)**	170,007
Bank credit facility transaction costs	**–**	(5,095)	**–**	(5,095)
Principal repayment on senior notes	**(34,248)**	(35,697)	**(34,248)**	(35,697)
Cross currency interest rate swap principal settlement	**(19,418)**	(17,969)	**(19,418)**	(17,969)
Changes in non-cash financing working capital	**124**	60	**247**	117
Cash flow from financing activities	**(485,614)**	22,576	**(433,206)**	(66,347)
Investing Activities				
Capital expenditures	**(148,573)**	(89,076)	**(324,628)**	(183,759)
Property and land acquisitions	**(94,415)**	(310,112)	**(142,633)**	(349,747)
Property dispositions	**571,095**	181,238	**630,788**	182,776
Purchase of marketable securities	**–**	(450)	**–**	(1,016)
Changes in non-cash investing working capital	**(5,150)**	6,219	**(30,415)**	(5,503)
Cash flow from investing activities	**322,957**	(212,181)	**133,112**	(357,249)
Effect of exchange rate changes on cash	**94**	(130)	**370**	(226)
Change in cash	**760**	(25,550)	**(3,998)**	(73,009)
Cash, beginning of period	**3,616**	26,099	**8,374**	73,558
Cash, end of period	**$ 4,376**	$ 549	**$ 4,376**	$ 549
Supplementary Cash Flow Information				
Cash income taxes (received)/ paid	**$ 45**	$ 465	**$ 168**	$ (7,816)
Cash interest paid	**$ 20,661**	$ 22,912	**$ 25,128**	$ 24,387

See accompanying notes to the Condensed Consolidated Financial Statements

Notes to Condensed Consolidated Financial Statements

For the three and six months ended June 30, 2011, with comparative figures for 2010.
All amounts are stated in Canadian dollars unless otherwise specified.

1. REPORTING ENTITY

These interim condensed consolidated financial statements ("interim Consolidated Financial Statements") and notes present the results of Enerplus Corporation and its subsidiaries, as successor to Enerplus Resources Fund. On January 1, 2011, Enerplus Resources Fund (the "Fund") converted from an income trust into a corporate entity under a Plan of Arrangement pursuant to the *Business Corporations Act (Alberta)* (the "Plan of Arrangement") and continued as Enerplus Corporation ("Enerplus" or the "Company"). Immediately following the conversion, the directors and management of Enerplus remained the same as immediately prior to the conversion and the Company continued to carry on the same business and own the same assets as immediately prior to conversion.

Under the Plan of Arrangement, investors holding Trust Units received one common share of Enerplus Corporation in exchange for each Trust Unit of the Fund, and investors holding Class B exchangeable limited partnership units in Enerplus Exchangeable Limited Partnership ("EELP") received 0.425 of a common share in Enerplus Corporation for each EELP unit held. Pursuant to the Plan of Arrangement, all outstanding securities of the Fund and EELP were cancelled and the Fund and EELP were dissolved.

As Enerplus and the Fund were under common control, and there was no change in control as a result of the Plan of Arrangement, the information herein including the consolidated financial statements for periods prior to the effective date of the Plan of Arrangement reflect the financial position, results of operations and cash flows as if Enerplus had always carried on the business formerly carried on by the Fund.

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 August 4, 2011.

2. BASIS OF PREPARATION

Enerplus' annual audited Consolidated Financial Statements for the year ended December 31, 2011 will be issued under International Financial Reporting Standards ("IFRS"). These interim Consolidated Financial Statements present Enerplus' results of operations and financial position under IFRS as at and for the six months ended June 30, 2011, including the 2010 comparative periods. As a result, they have been prepared in accordance with IFRS 1, "First-time Adoption of International Financial Reporting Standards" and with International Accounting Standard ("IAS") 34, "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IASB"). These interim Consolidated Financial Statements do not include all the necessary annual disclosures in accordance with IFRS. Previously, the Company prepared its interim and annual Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP").

The preparation of these interim Consolidated Financial Statements resulted in certain changes to the Company's accounting policies as compared to those disclosed in the annual audited Consolidated Financial Statements for the period ended December 31, 2010 issued under Canadian GAAP. A summary of the significant changes to the accounting policies is disclosed in Note 16 along with reconciliations presenting the impact of the transition to IFRS for the comparative periods as at January 1, 2010, as at and for the three and six months ended June 30, 2010 and as at and for the twelve months ended December 31, 2010.

(a) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for the following items which are measured at fair value:

- cash;
- derivative financial instruments;
- available for sale financial instruments; and
- share-based payment transactions.

(b) Functional and Presentation Currency

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

(c) Use of Estimates and Judgment

The preparation of financial statements requires management to use judgment, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results could differ from those estimated.

The amounts recorded for depletion and depreciation of the oil and gas assets and for decommissioning liabilities are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future periods affected.

IFRS requires that the Company's oil and gas assets be aggregated into cash-generating units, based on their ability to generate largely independent cash flows, which are used to assess the assets for impairment. The determination of the Company's cash-generating units is subject to management's judgment.

The decision to transfer assets from exploration and evaluation to property, plant and equipment is based on management's assessment of technical feasibility and commercial viability and this is subject to management's judgment.

The estimated fair value of derivative instruments, by their very nature, are subject to measurement uncertainty.

Compensation costs recorded for the stock option plan are subject to estimation as they are calculated using the Black Scholes option pricing model which is based on significant assumptions such as volatility, dividend yield, expected term and forfeiture rate. Other compensation plans are performance based and are also subject to management's judgment as to whether or not certain performance criteria will be met.

The determination of the income tax provision and other tax issues can be complex and require management judgment. As such, income taxes are subject to measurement uncertainty. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations may result in an increase or decrease in the Company's provision for income taxes.

Additional details concerning estimates and judgment have been provided in Note 3.

3. SIGNIFICANT ACCOUNTING POLICIES

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

(a) Basis of Consolidation

These interim Consolidated Financial Statements include the accounts of Enerplus and its subsidiaries. Intercompany balances and transactions are eliminated on consolidation. Interests in jointly controlled assets are accounted for using the proportionate consolidation method, 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 and assets that meet the definition of a business under IFRS. 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 crude oil and natural gas is recognized when title passes from the Company to its customers and 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 and 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) Exploration and Evaluation Assets ("E&E) and Property, Plant and Equipment ("PP&E")

(i) E&E Assets

Costs incurred prior to acquiring the legal right to explore an area are charged directly to net income.

Costs incurred after the legal right to explore is obtained but before technical feasibility and commercial viability of the area has been established are capitalized as E&E assets. These costs generally include unproved property acquisition costs, geological and geophysical costs, sampling and appraisals, related drilling and completion costs and directly attributable internal costs.

Once an area is determined to be technically feasible and commercially viable the accumulated costs are tested for impairment. The carrying value, net of any impairment, is then reclassified to PP&E as a Developed and Producing ("D&P") asset. If an area is determined not to be technically feasible and commercially viable, or the Company discontinues its exploration and evaluation activity, any unrecoverable costs are charged to net income.

(ii) PP&E

All costs directly associated with the development of crude oil and natural gas reserves are capitalized on an area-by-area basis if they extend or enhance the recoverable reserves of the underlying assets. These expenditures are referred to as D&P assets and include assets where technical feasibility and commercial viability has been determined. Costs in this category include proved property acquisitions, drilling and completion costs, gathering and infrastructure, capitalized decommissioning costs, directly attributable internal costs and transfers of exploration and evaluation assets. Repairs and maintenance and operational costs that do not extend or enhance the recoverable reserves are charged to net income in the period.

D&P assets are aggregated into cash generating units ("CGUs") for the purposes of impairment testing and depletion calculations. CGUs are groups of assets that generate independent cash inflows and are generally defined based on geographic areas, with consideration given to how the assets are managed.

Gains and losses on disposals of properties are determined by comparing the proceeds to the net carrying value of the property and are recognized in net income.

(d) Depletion and Depreciation

The net carrying value of D&P assets is depleted using the unit of production method, calculated as the ratio of production in the year compared to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Reserves and production are converted to equivalent units on the basis of 6mcf = 1 bbl, reflecting the approximate energy content. Proved plus probable reserves are generally estimated using independent reserve engineers and represent the estimated quantities of crude oil and natural gas which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years.

E&E assets are not depleted.

(e) Impairment

(i) E&E

E&E assets are tested for impairment when indicators of impairment exist or when technical feasibility and commercial viability are established and the assets are reclassified to PP&E. The impairment test compares the E&E assets' carrying value to recoverable amount plus any excess recoverable amounts on D&P assets on a country by country basis. E&E assets that are determined not to be technically feasible and commercially viable are charged to net income.

(ii) PP&E and Goodwill

D&P assets included in PP&E are reviewed for impairment at a CGU level when indicators of impairment exist. When indicators of impairment exist, the carrying value of each CGU, including goodwill, is compared to its recoverable amount which is defined as the higher of its fair value less cost to sell ("FVLCTS") or its value in use ("VIU"). FVLCTS is determined to be the amount for which the asset could be sold in an arm's length transaction. VIU is based upon the estimated before tax net present value of the Company's proved plus probable reserves, as prepared by independent reserve evaluators. These estimates of future net revenues are based on forecast prices and costs, and are stated prior to the provision of financing and general and administrative expenses and after the deduction of royalties and estimated future capital expenditures. Forecast prices reflect heating values, quality differentials and transportation costs specific to the Company's assets. Future net revenues are discounted using the Company's weighted average cost of capital.

Where the carrying value exceeds the recoverable amount an impairment loss exists and is charged to net income. Impairment losses are first recorded against goodwill within a CGU and the remainder is recorded against the D&P assets.

Reversals of impairments are recognized when events or circumstances that triggered the original impairment have changed. Impairments can only be reversed in future periods up to the carrying amount that would have been determined, net of depletion and depreciation, had no impairment losses been previously recognized. Goodwill impairments are not reversed in future periods.

(f) Foreign Currency

(i) Foreign currency transactions

Transactions in foreign currencies are generally translated to Canadian dollars at the average exchange rate for the period. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. 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 ("CTA") which is part of accumulated other comprehensive income ("AOCI").

(g) Financial Instruments

(i) Non-derivative financial instruments

Non-derivative financial instruments comprise cash, accounts receivable, accounts payable, dividends payable to shareholders and debt. Cash is classified as "fair value through profit or loss" and is carried at fair value. Accounts receivable are classified as "loans and receivables" and are carried at amortized cost less any allowance for impairment. Accounts payable, dividends payable to shareholders and debt are classified as "other financial liabilities" and are carried at amortized cost.

Enerplus has certain equity investments in entities involved in the oil and gas industry which are included in other assets on the Consolidated Balance Sheets. These investments are classified as "available-for-sale" and are carried at fair value with changes in fair value recorded in other comprehensive income. The fair value of investments that are publicly traded are determined by reference to quoted market bid prices at the close of business on the balance sheet date. For investments where there is no public market, fair value is determined using valuation techniques including using recent arm's length market transactions. 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.

Enerplus capitalizes transaction costs on premiums and long-term debt. These costs are amortized using the effective interest method.

(ii) 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 "fair value through profit or loss" and are recorded at fair value on the Consolidated Balance Sheets 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 accounts for its physical delivery purchase and sales contracts as executory contracts as they were entered into and continue to be held for the purpose of receipt or delivery of products in accordance with its expected purchase, sale or usage requirements. As such, these contracts are not considered to be derivative financial instruments. Settlements on these physical contracts are recognized in net income over the term of the contracts as they occur.

(h) Goodwill

Enerplus recognizes goodwill relating to corporate acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired companies. The portion of goodwill that relates to its U.S. operations fluctuates due to changes in foreign exchange rates. For the purposes of impairment testing, goodwill is allocated to the CGUs that benefited from the synergies of the respective business combinations and is tested for impairment in conjunction with the CGU. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

(i) Assets Held for Sale

Non-current assets, or disposal groups consisting of assets and liabilities, are classified as held for sale if management intends to sell the assets, the sale is highly probable and the assets are available for immediate sale in their present condition.

Assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell. Any impairments are recognized in net income in the period measured. Non-current assets and disposal groups held for sale are presented in current assets and liabilities within the Consolidated Balance Sheets. Assets held for sale are not depreciated, depleted or amortized.

(j) Share Based Payments

Enerplus uses 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 is charged to earnings as general and administrative expenses over the vesting period of the options, with a corresponding increase in contributed surplus. When options are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to shareholders' capital.

Enerplus recognizes a liability in respect of its cash settled Performance Share and Restricted Share 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 general and administrative expenses in net income.

(k) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by recognizing the present value of the estimated future cash flows, discounted using a risk-free rate.

(l) Decommissioning Liabilities

Enerplus' oil and gas operating activities give rise to dismantling, decommissioning and site remediation activities. Enerplus recognizes a liability for the estimated present value of the future decommissioning liabilities at each Balance Sheet date. The associated decommissioning cost is capitalized and amortized over the same period as the underlying asset. Changes in the estimated liability resulting from revisions to estimated timing, amount of cash flows, or changes in the discount rate are recognized as a change in the decommissioning liability and related capitalized decommissioning cost.

Amortization of capitalized decommissioning costs is included in depreciation, depletion and amortization in net income. Increases in decommissioning liabilities resulting from the passage of time are recorded as accretion which is included with finance expense in net income. Actual expenditures incurred are charged against the decommissioning liability.

(m) Income Tax

Income tax expense comprises current and deferred tax. Income tax expense is recognized in net income except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, along with any adjustment to tax payable in respect of previous years. Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(n) 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.

(o) New Pronouncements Adopted

March 31, 2011 was Enerplus' first reporting period under IFRS. Accounting standards effective for periods beginning on or after January 1, 2010 have been adopted as part of the transition to IFRS.

(p) Recent Pronouncements Issued

The following Standards and Interpretations which have not been applied in these financial statements were in issue but not yet effective at June 30, 2011. We are currently evaluating the impact of these standards on our operations and financial position.

- IFRS 9 *Financial Instruments* – The standard is required to be adopted for periods beginning January 1, 2013. Portions of the standard remain in development and the full impact of the standard will not be known until the project is complete.
- IFRS 10 *Consolidated Financial Statements* – The standard is required to be adopted for periods beginning January 1, 2013.
- IFRS 11 *Joint Arrangements* – The standard is required to be adopted for periods beginning January 1, 2013.
- IFRS 12 *Disclosure of Interests in Other Entities* – The standard is required to be adopted for periods beginning January 1, 2013.
- IFRS 13 *Fair Value Measurement* – The standard is required to be adopted for periods beginning January 1, 2013.
- IAS 1 *Presentation of Items of Other Comprehensive Income* – The standard is required to be adopted for periods beginning on or after July 1, 2012.
- IAS 27 *Consolidation and Separate Financial Statements* – The standard is required to be adopted for periods beginning January 1, 2013.
- IAS 28 *Investments in Joint Ventures* – The standard is required to be adopted for periods beginning January 1, 2013.

4. E&E ASSETS

($ thousands)

Carrying value	**E&E assets**
At January 1, 2010	$ 580,184
Capital spending and acquisitions	1,279,361
Dispositions	(260,697)
Impairment expense	(11,745)
Foreign currency translation adjustment	(41,725)
At December 31, 2010	$ 1,545,378
Capital spending and acquisitions	319,623
Dispositions	(295,961)
Transfers to Property, Plant and Equipment	(825,467)
Foreign currency translation adjustment	(18,004)
As at June 30, 2011	**$ 725,569**

E&E assets consist of projects that management has not fully evaluated for technical feasibility and commercial viability.

As at June 30, 2011 the E&E asset balance is $725,569,000 (December 31, 2010 – $1,545,378,000), consisting primarily of Marcellus and Saskatchewan Bakken assets along with associated undeveloped lands. The transfer of approximately $825,467,000 from E&E assets to PP&E during the year was based on management's assessment of the technical feasibility and commercial viability, the majority of which relates to U.S. Fort Berthold and Marcellus assets and various oil assets in Canada.

5. PP&E

($ thousands)

Carrying value before accumulated depletion and depreciation	D&P assets	Office and other	Total
As at January 1, 2010	$ 4,402,061	$ 55,639	$ 4,457,700
Capital spending and acquisitions	269,346	4,004	273,350
Change in decommissioning costs	9,996	–	9,996
Dispositions	(399,354)	–	(399,354)
Foreign currency translation adjustment	(28,610)	(101)	(28,711)
As at December 31, 2010	$ 4,253,439	$ 59,542	$ 4,312,981
Capital spending and acquisitions	142,619	5,018	147,637
Transfers from Exploration and Evaluation	825,467	–	825,467
Change in decommissioning costs	(2,254)	–	(2,254)
Dispositions	(36,683)	–	(36,683)
Foreign currency translation adjustment	(34,617)	(54)	(34,671)
As at June 30, 2011	**$ 5,147,971**	**$ 64,506**	**$ 5,212,477**

Accumulated Depletion and Depreciation	D&P assets	Office and other	Total
As at January 1, 2010	$ –	$ 37,361	$ 37,361
Depletion, Depreciation and Amortization	453,387	7,770	461,157
Impairment	375,993	–	375,993
Foreign currency translation adjustment	(2,049)	(49)	(2,098)
As at December 31, 2010	$ 827,331	$ 45,082	$ 872,413
Depletion, Depreciation and Amortization	200,319	3,277	203,596
Impairment	32,394	–	32,394
Foreign currency translation adjustment	(2,359)	–	(2,359)
As at June 30, 2011	**$ 1,057,685**	**$ 48,359**	**$ 1,106,044**

Net carrying value	Developed and producing assets	Office and other	Total
As at January 1, 2010	$ 4,402,061	$ 18,278	$ 4,420,339
As at December 31, 2010	$ 3,426,108	$ 14,460	$ 3,440,568
As at June 30, 2011	**$ 4,090,286**	**$ 16,147**	**$ 4,106,433**

As at June 30, 2011 the Marcellus carry commitment balance remaining was US$83,880,000.

6. GAINS ON DISPOSITION

For the three months ended June 30, 2011 Enerplus disposed of assets for proceeds of $571,095,000 resulting in a gain of $271,910,000. For the six months ended June 30, 2011 Enerplus disposed of assets for proceeds of $630,788,000 resulting in a gain of $298,145,000.

7. IMPAIRMENT EXPENSE

($ thousands)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Goodwill	**$ –**	$ 26,909	**$ –**	$ 287,653
D&P natural gas CGUs	**–**	3,366	**32,394**	40,205
Impairment expense	**$ –**	$ 30,275	**$ 32,394**	$ 327,858

D&P impairment expenses for the three and six months ended June 30, 2011 were nil (June 30, 2010 – $3,366,000) and $32,394,000 (June 30, 2010 – $40,205,000) respectively. Goodwill impairment expenses for the three and six months ended June 30, 2010 were $26,909,000 and $287,653,000 respectively. The impairment losses were a result of lower forecasted natural gas prices. The recoverable amount was based on the assets value in use, estimated using the present value of future net cash flows, discounted at 10%.

8. OTHER ASSETS

Other assets consist of Enerplus' equity investments in entities involved in the oil and gas industry. For the three and six months ended June 30, 2011 the change in fair value of these investments represented an unrealized gain of $50,270,000 (June 30, 2010 – $6,305,000) and $53,218,000 (June 30, 2010 – $43,286,000), net of tax, respectively. The majority of the gain was attributable to the increase in fair value of Enerplus' investment in Laricina Energy Ltd.

9. DEBT

($ thousands)	June 30, 2011	December 31, 2010	January 1, 2010
Current:			
Current portion of long-term debt	**$ 44,451**	$ 45,845	$ 36,631
	44,451	45,845	36,631
Long-term:			
Bank credit facility	**$ 14,741**	$ 234,713	$ –
Senior notes			
CDN$40 million (Matures June 18, 2015)	**40,000**	40,000	40,000
US$40 million (Matures June 18, 2015)	**38,572**	39,784	41,864
US$225 million (Matures June 18, 2021)	**216,968**	223,785	235,485
US$54 million (Matures October 1, 2015)(1)	**41,658**	42,967	56,516
US$175 million (Matures June 19, 2014)(1)(2)	**68,073**	105,311	148,411
	420,012	686,560	522,276
Total debt	**$ 464,463**	$ 732,405	$ 558,907

(1) A portion of which has been classified as current.
(2) The outstanding US principal as at June 30, 2011 is US $105,000,000.

During 2011 Enerplus entered into foreign exchange swaps with respect to the principal repayment on the US $225,000,000 senior notes. Refer to Note 15 for additional information.

10. DECOMMISSIONING LIABILITY

($ thousands)	June 30, 2011	December 31, 2010
Decommissioning liability, beginning of year	**$ 392,709**	$ 385,885
Changes in estimates	**(2,731)**	59,575
Property acquisition and development activity	**913**	6,894
Dispositions	**(512)**	(56,629)
Decommissioning liabilities settled	**(8,171)**	(17,240)
Accretion	**6,794**	14,224
Decommissioning liability, end of period	**$ 389,002**	$ 392,709

11. FINANCE EXPENSE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2011	2010	2011	2010
Realized:				
Interest on bank debt and senior notes	**$ 12,690**	$ 9,875	**$ 24,590**	$ 19,090
Unrealized:				
Cross currency interest rate swap (gain)/loss	**1,927**	754	**1,095**	121
Interest rate swap (gain)/loss	**(446)**	131	**(1,207)**	(782)
Amortization of premiums and transaction costs	**284**	(180)	**569**	(360)
Accretion of decommissioning liability	**3,379**	3,622	**6,794**	7,510
Change in fair value of EELP units	**–**	(1,768)	**–**	746
Finance expense	**$ 17,834**	$ 12,434	**$ 31,841**	$ 26,325

12. FOREIGN EXCHANGE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2011	2010	2011	2010
Realized:				
Foreign exchange (gain)/loss	**$ 13,049**	$ 16,906	**$ 20,308**	$ 14,470
Unrealized:				
(Gain)/loss on translation of U.S. dollar debt	**(1,189)**	20,873	**(13,123)**	5,507
(Gain)/loss on cross currency interest rate swap	**(17,293)**	(21,576)	**(13,366)**	(15,562)
(Gain)/loss on foreign exchange swaps	**891**	(2,570)	**3,301**	(1,191)
Foreign exchange (gain)/loss	**$ (4,542)**	$ 13,633	**$ (2,880)**	$ 3,224

13. INCOME TAX EXPENSE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2011	2010	2011	2010
Current tax expense				
Canada	**$ –**	$ –	**$ –**	$ –
U.S.	**43,214**	409	**43,996**	409
Total current	**$ 43,214**	$ 409	**$ 43,996**	$ 409
Deferred tax expense/(recovery)	**95,151**	7,459	**44,740**	7,050
Total income tax expense/(recovery)	**$ 138,365**	$ 7,868	**$ 88,736**	$ 7,459

Enerplus recorded current taxes for the three and six months ended June 30, 2011 of $43,214,000 and $43,996,000 respectively as a result of the Marcellus disposition.

14. SHAREHOLDERS' CAPITAL

Effective January 1, 2011, pursuant to the Plan of Arrangement, former unitholders of the Fund received one common share in Enerplus Corporation in exchange for each trust unit held and 0.425 of a common share in Enerplus Corporation for each exchangeable partnership unit of EELP held. On January 1, 2011, all outstanding securities of the Fund and EELP were cancelled. For comparative purposes, references to share capital and the stock option plan refer to trust units and the trust unit rights incentive plan ("TURIP") that were outstanding during 2010 and subsequently converted into share capital and stock options under the Plan of Arrangement.

Under IFRS, EELP units and trust unit rights were considered liabilities and were recorded on the consolidated balance sheet at their amortized fair value. Upon conversion to a corporation on January 1, 2011 these liabilities were effectively converted into equity and the EELP liability of $44,387,000 was recorded to share capital and the trust unit rights liability of $20,156,000 was recorded to contributed surplus. For more information refer to Note 14(c).

Pursuant to the Plan of Arrangement, shareholders' capital was reduced by the amount of the accumulated deficit of the Company on December 31, 2010 of $2,314,775,000.

(a) Share Capital

Authorized: Unlimited number of common shares Issued: (thousands)	Six months ended June 30, 2011		Year ended December 31, 2010	
	Shares	**Amount**	**Shares**	**Amount**
Balance, beginning of year	**176,946**	**$ 5,639,380**	174,349	$ 5,576,763
Corporate Conversion:				
Reclassification of EELP units (non-cash)	**1,703**	**44,387**	–	–
Reclassification of Accumulated Deficit (non-cash)	**–**	**(2,314,775)**	–	–
Issued for cash:				
Dividend reinvestment plan	**852**	**24,553**	1,212	28,781
Pursuant to stock option plan	**487**	**9,714**	375	6,638
Non-cash:				
Pursuant to stock option plan	**–**	**7,346**	–	3,014
Conversion of EELP units	**–**	**–**	1,010	24,184
Balance, end of period	**179,988**	**$ 3,410,605**	176,946	$ 5,639,380

(b) Dividends

For the three and six months ended June 30, 2011, Enerplus paid dividends of $0.18 per share per month for a total of $97,077,000 (June 30, 2010 – $95,909,000) and $193,763,000 (June 30, 2010 – $191,621,000) respectively.

(c) Stock Option Plan

In connection with the Plan of Arrangement, Enerplus assumed all of the obligations of the Fund in respect of outstanding trust unit rights and no further grants will be made under the trust unit rights incentive plan. Outstanding trust unit rights were adjusted to entitle rights holders to purchase common shares of Enerplus in lieu of trust units on a one-for-one basis. No adjustments were made to exercise prices or vesting terms and the declining strike price mechanism will continue for these rights. Under IFRS outstanding trust unit rights were considered liabilities and were recorded on the consolidated balance sheet at fair value at each reporting period with any changes in fair value recorded to net income. On the January 1, 2011 conversion, outstanding rights ceased being liabilities and became equity based awards. As a result, the amortized fair value of $20,156,000 was reclassified from a liability to contributed surplus and their remaining unamortized fair value will be expensed over the vesting period of the rights. When the rights are exercised, the proceeds together with the amount recorded in contributed surplus, are recorded to shareholders' capital.

A new stock option plan for employees and officers of Enerplus was approved by shareholders in conjunction with the Plan of Arrangement. Options granted under the plan vest over a three year period and expire seven years after the grant date. The exercise price is equal to the market price at the time of the grant with no declining strike price mechanism. Enerplus uses the Black Scholes model to estimate the fair value of options granted under the plan. Previously, Enerplus used a binomial lattice model to estimate the fair value of rights granted under the trust unit rights incentive plan.

The following assumptions were used to arrive at the estimate of fair value for each of the respective reporting periods:

	June 30, 2011	December 31, 2010[(1)]	January 1, 2010[(1)]
Dividend yield	**7.11%**	7.12%	9.13%
Volatility	**35.00%**	44.23%	44.22%
Risk-free interest rate	**2.38%**	2.23%	2.48%
Forfeiture rate	**8.5%**	12.50%	12.40%
Expected life	**4.5 years**	3.4 years	3.9 years
Right's exercise price reduction	**$ –**	$ 0.74	$ 1.41

(1) Refers to the previous trust unit rights plan and calculated using a binomial lattice model.

The weighted average grant date fair value of options granted in 2011 was $4.80 (June 30, 2010 – $4.26). At June 30, 2011, 2,725,000 options were exercisable at a weighted average reduced exercise price of $36.78 with a weighted average remaining contractual term of 3.3 years, giving an aggregate intrinsic value of $8,980,000 (June 30, 2010 – $2,770,000).

For the six months ended June 30, 2011, 487,000 stock options were exercised at a weighted average reduced exercise price of $19.94. The weighted average share price during the period was $30.86.

For the three and six months ended June 30, 2011 Enerplus expensed $3,295,000 and $6,778,000 respectively of stock based compensation expense, which is included in general and administrative expense. The unamortized fair value of $12,157,000 at June 30, 2011 will be recognized in net income over the remaining vesting period. Activity for the periods is as follows:

	Six months ended June 30, 2011		Year ended December 31, 2010	
	Number of Options (000's)	Weighted Average Exercise Price[(1)]	Number of Options (000's)	Weighted Average Exercise Price[(1)]
Options outstanding				
Beginning of year	**5,457**	**$ 32.11**	5,250	$ 34.84
Granted	**2,014**	**30.40**	1,749	23.60
Exercised	**(487)**	**19.94**	(375)	17.50
Forfeited and expired	**(888)**	**41.24**	(1,167)	36.28
End of period	**6,096**	**$ 31.19**	5,457	$ 32.11
Options exercisable at the end of period	**2,725**	**$ 36.78**	2,565	$ 42.27

(1) Exercise price reflects grant prices less any reduction in strike price for outstanding rights under the rights incentive plan.

Contributed Surplus, as presented on the Consolidated Balance Sheets, is comprised of the following items:

($ thousands)	Six months ended June 30, 2011	Year ended December 31, 2010
Balance, beginning of year	**$ 3,795**	$ 3,795
Reclassification of trust unit rights liability	**20,156**	–
Stock option plan – exercised	**(7,346)**	–
Stock option plan – expensed	**6,778**	3,795
Balance, end of period	**$ 23,383**	$ 3,795

(d) Basic and Diluted Earnings Per Share

Net income per share has been determined based on the following:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2011	2010	2011	2010
Net income/(loss)	**$ 267,982**	$ 76,502	**$ 297,531**	$ (107,520)
Finance expense on EELP units	**–**	(8,484)	**–**	–
Diluted income/(loss)	**$ 267,982**	$ 68,018	**$ 297,531**	$ (107,520)
(units – thousands)				
Weighted average shares	**179,583**	175,705	**179,209**	175,099
Dilutive impact of options	**502**	268	**502**	269
Dilutive impact of EELP units	**–**	1,809	**–**	–
Diluted shares	**180,085**	177,782	**179,711**	175,368

(e) Long-term incentive plans

In conjunction with the Plan of Arrangement Enerplus assumed all of the obligations of the Fund under the Restricted Share Unit ("RSU") plan for employees and adopted a Performance Share Unit ("PSU") plan for management and executives. Values calculated for Enerplus' former Restricted Trust Unit ("RTU") plan will be based on common shares and dividends of Enerplus along with the applicable historic distributions of the Fund.

Under the RSU plan employees receive cash 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. Upon vesting, plan participants receive a cash payment based on the value of the underlying notional shares plus accrued dividends over the vesting period.

Under the PSU plan executives and management receive cash 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. Upon vesting, the plan participant receives a cash payment based on the value of the underlying shares plus notional accrued dividends which are adjusted by a multiplier that ranges from 0.5 to 2.0 depending on the performance of Enerplus compared to its peers over the three year period.

For the three and six months ended June 30, 2011 the Company recorded cash compensation costs of $4,088,000 (June 30, 2010 – $2,610,000) and $9,164,000 (June 30, 2010 – $6,286,000) respectively, which was included in general and administrative expenses. At June 30, 2011 the long term incentive plans had a liability balance of $16,499,000.

The following table summarizes the PSU and RSU activity for the six months ended June 30, 2011:

(thousands)	Number of PSUs	Number of RSUs
Balance, beginning of year	**–**	**999**
Granted	**186**	**452**
Vested	**(7)**	**(426)**
Forfeited	**(4)**	**(76)**
Balance, end of period	**175**	**949**

15. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

(a) Fair Value of Non-Derivative Financial Instruments

The fair values of cash, accounts receivable, accounts payable, dividends payable to shareholders and amounts owing under the bank credit facility approximate their carrying amounts at June 30, 2011 and December 31, 2010 due to their short-term maturities. At June 30, 2011 the combined fair values of Enerplus' senior notes was $514,615,000 and the carrying amount was $449,721,000 (December 31, 2010 – fair value of $559,049,000 and carrying value of $497,692,000). The fair value of the senior notes was estimated by discounting future interest and principal payments using available market information at the balance sheet date.

(b) Fair Value of Derivative Financial Instruments

Derivative instruments are recorded at their estimated fair value using observable market inputs including forward curves. The deferred financial assets and liabilities on the Consolidated Balance Sheets result from recording these instruments at their fair value. As at June 30, 2011 $3,397,000 of unamortized transaction costs associated with the Company's credit facility were included in deferred financial assets on the Consolidated Balance Sheets.

The deferred financial liability relating to crude oil instruments is $32,283,000 at June 30, 2011 including deferred premiums of $4,004,000. At June 30, 2011 Enerplus did not have any outstanding natural gas derivative instruments.

The following table summarizes the fair value as at June 30, 2011 and change in fair value for the six months ended June 30, 2011:

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Commodity Derivative Instruments		Total
					Oil	Gas	
Deferred financial assets/(liabilities), beginning of year	$ (3,640)	$ (61,095)	$ 385	$ (501)	$ (38,344)	$ 12,641	$ (90,554)
Change in fair value gain/(loss)	1,207(1)	12,271(2)	(3,301)(3)	3,290(4)	6,061(5)	(12,641)(5)	6,887
Deferred financial assets/(liabilities), end of period	**$ (2,433)**	**$ (48,824)**	**$ (2,916)**	**$ 2,789**	**$ (32,283)**	**$ –**	**$ (83,667)**
Balance Sheet classification:							
Current assets/(liabilities)	**$ (1,576)**	**$ (16,307)**	**$ –**	**$ 2,789**	**$ (32,283)**	**$ –**	**$ (47,377)**
Non-current assets/(liabilities)	**$ (857)**	**$ (32,517)**	**$ (2,916)**	**$ –**	**$ –**	**$ –**	**$ (36,290)**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (gain of $13,366) and finance expense (loss of $1,095).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments (see below).

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

($ thousands)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Change in fair value gain/(loss)	**$ 72,578**	$ 15,578	**$ (6,580)**	$ 44,972
Net realized cash gain/(loss)	**(20,761)**	17,287	**(17,730)**	21,241
Commodity derivative instruments gain/(loss)	**$ 51,817**	$ 32,865	**$ (24,310)**	$ 66,213

(c) Risk Management

Enerplus is exposed to commodity price fluctuations as part of its normal business operations. Risk management policies have been established by the Board of Directors to assist in managing a portion of these risks, with the goal of protecting earnings, funds flow and shareholder value. Enerplus manages a portion of these risks through a combination of financial derivative and physical delivery sales contracts.

(i) Commodity Price Instruments

The Company's policy is to enter into commodity contracts considered appropriate to a maximum of 80% of forecasted production volumes net of royalties. Enerplus' outstanding commodity derivative contracts at July 27, 2011 are listed below. Enerplus did not have any outstanding natural gas derivative contracts.

Crude Oil:

		WTI US$/bbl					
	Daily Volumes bbls/day	Purchased Call	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps	Brent – WTI (US$/bbl)
Term							
Jul 1, 2011 – Dec 31, 2011							
Purchased Call	1,500	$ 105.00	–	–	–	–	–
Purchased Call	1,000	$ 100.00	–	–	–	–	–
Purchased Call	500	$ 92.00	–	–	–	–	–
Swap	1,000	–	–	–	–	$ 87.65	–
Swap	500	–	–	–	–	$ 85.20	–
Swap	500	–	–	–	–	$ 88.95	–
Swap	500	–	–	–	–	$ 91.20	–
Swap	500	–	–	–	–	$ 91.88	–
Swap	500	–	–	–	–	$ 92.65	–
Swap	500	–	–	–	–	$ 94.80	–
Swap	1,000	–	–	–	–	$ 82.36	–
Swap	500	–	–	–	–	$ 85.50	–
Swap	500	–	–	–	–	$ 86.25	–
Swap	500	–	–	–	–	$ 80.30	–
Swap	1,500	–	–	–	–	$ 82.60	–
Swap	500	–	–	–	–	$ 81.69	–
Swap	500	–	–	–	–	$ 84.25	–
Swap	500	–	–	–	–	$ 85.40	–
Swap	500	–	–	–	–	$ 87.70	–
Swap	500	–	–	–	–	$ 86.73	–
Swap	500	–	–	–	–	$ 87.51	–
Swap	500	–	–	–	–	$ 89.20	–
Swap	500	–	–	–	–	$ 89.65	–
Swap	500	–	–	–	–	$ 87.20	–
Swap	500	–	–	–	–	$ 88.00	–
Swap	500	–	–	–	–	$ 89.00	–
Swap	500	–	–	–	–	$ 90.00	–
Swap	500	–	–	–	–	$ 91.25	–
Swap	500	–	–	–	–	$ 90.75	–
Swap	500	–	–	–	–	$ 92.40	–
Sold Put	1,500	–	–	–	$ 55.00	–	–
Sold Put	1,500	–	–	–	$ 58.00	–	–

	Daily Volumes bbls/day	WTI US$/bbl Purchased Call	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps	Brent – WTI (US$/bbl)
Jan 1, 2012 – Dec 31, 2012							
Swap	1,000	–	–	–	–	$ 90.40	–
Swap	1,000	–	–	–	–	$ 90.18	–
Swap	500	–	–	–	–	$ 91.84	–
Swap	500	–	–	–	–	$ 92.25	–
Swap	500	–	–	–	–	$ 95.00	–
Swap	500	–	–	–	–	$ 95.50	–
Swap	500	–	–	–	–	$ 100.15	–
Swap	500	–	–	–	–	$ 99.35	–
Swap	500	–	–	–	–	$ 99.40	–
Swap	500	–	–	–	–	$ 100.50	–
Swap	500	–	–	–	–	$ 101.05	–
Swap	500	–	–	–	–	$ 103.00	–
Swap	1,000	–	–	–	–	$ 103.06	–
Swap	500	–	–	–	–	$ 105.25	–
Swap(1)	500	–	–	–	–	$ 107.00	–
Swap(2)	500	–	–	–	–	$ 101.50	–
Swap(2)	500	–	–	–	–	$ 102.55	–
Three-way collar	1,000	–	$ 133.00	$ 103.00	$ 65.00	–	–
Brent – WTI Spread(2)	500	–	–	–	–	–	$ 14.95
Brent – WTI Spread(2)	500	–	–	–	–	–	$ 14.50
Jan 1, 2013 – Dec 31, 2013							
Swap(2)	500	–	–	–	–	$ 102.50	–
Swap(2)	500	–	–	–	–	$ 103.40	–

(1) Financial contracts entered into during the second quarter of 2011.
(2) Financial contracts entered into subsequent to June 30, 2011.

Electricity:

Enerplus is subject to electricity price fluctuations and it manages this risk by entering into forward fixed rated electricity derivative contracts on a portion of its electricity requirements. The Company's outstanding electricity derivative contracts at July 27, 2011 are summarized below:

Term	Volumes MWh	Price CDN$/MWh
July 1, 2011 – December 31, 2011	3.0	$ 66.00
July 1, 2011 – December 31, 2011	3.0	$ 55.00
July 1, 2011 – December 31, 2011	3.0	$ 57.25
July 1, 2011 – December 31, 2011	3.0	$ 49.00
July 1, 2011 – December 31, 2011	2.0	$ 50.00
July 1, 2011 – December 31, 2011	2.0	$ 47.50
January 1, 2012 – December 31, 2012	3.0	$ 54.50
January 1, 2012 – December 31, 2012	2.0	$ 50.50
January 1, 2012 – December 31, 2012	5.0	$ 48.00

(ii) Foreign Exchange Swaps

During the first six months of 2011 Enerplus entered into foreign exchange swaps with respect to the principal repayment on the US $225,000,000 senior notes. As of July 27, 2011 $175,000,000 of notional principal has been swapped at a US$/CDN$ rate of 1.004.

16. TRANSITION TO IFRS

These Interim Consolidated Financial Statements have been prepared in accordance with IFRS 1, "First-time Adoption of International Financial Reporting Standards" and with IAS 34, "Interim Financial Reporting", as issued by the IASB. Prior to the adoption of IFRS, Enerplus prepared its interim and annual Consolidated Financial Statements in accordance with Canadian GAAP.

IFRS 1 requires the presentation of comparative information as at the January 1, 2010 transition date along with subsequent comparative periods and, aside from the IFRS 1 exemptions available at the date of transition, retrospective application of IFRS accounting policies at the date of transition. In addition, IFRS requires the application of consistent accounting policies for all the periods presented.

To assist with the transition to IFRS the provisions of IFRS allow for certain mandatory and optional exemptions for first-time adopters to alleviate the retrospective application of all IFRS. Enerplus has applied the following exemptions:

Property, Plant and Equipment – This exemption allows companies that followed the Canadian GAAP full cost accounting guideline to allocate their historic net PP&E to CGUs on the date of transition. Enerplus has allocated PP&E into CGUs in Canada and the U.S., based on proved plus probable reserve values as at January 1, 2010.

Business Combinations – This is an optional exemption to the requirement to retroactively restate any past business combinations recorded under Canadian GAAP. Enerplus applied this exemption and therefore will not be retroactively restating past business combinations.

Cumulative Translation Adjustment ("CTA") – IFRS 1 provides an optional exemption to the requirement to retroactively restate CTA and instead allows entities to eliminate the CTA balance as of the date of transition. Enerplus applied this exemption and set CTA to zero at January 1, 2010 which increased the accumulated deficit by approximately $82 million.

Borrowing Costs – This exemption allows entities to be exempt from capitalizing interest on qualifying assets where active development commenced before January 1, 2010. Enerplus' Kirby oil sands asset, which was sold in October 2010, would be considered a "qualifying asset" on January 1, 2010. As a result of applying the exemption no interest was capitalized for Kirby.

The adoption of IFRS has had no impact on the Company's net increase or decrease in cash for any given period. As a result, although the changes made to the Consolidated Balance Sheets, Consolidated Income Statements and Consolidated Statements of Comprehensive Income resulted in reclassifications of various amounts on the Consolidated Statement of Cash Flows, no Consolidated Statement of Cash Flows has been included in this Note. The following financial statements, restated to comply with IFRS, have been provided:

- Consolidated Balance Sheets as at:
  - January 1, 2010;
  - June 30, 2010 and
  - December 31, 2010.
- Consolidated Income Statement for the periods ended:
  - June 30, 2010 and
  - December 31, 2010.
- Consolidated Statement of Comprehensive Income for the periods ended:
  - June 30, 2010 and
  - December 31, 2010.
- Consolidated Statement of Changes in Equity as at:
  - June 30, 2010 and
  - December 31, 2010.

Consolidated Balance Sheet

As at January 1, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments E&E	Impairment	Other Assets	Decommis-sioning Liability	EELP Units	TURIP	Foreign Exchange	Income Tax	IFRS
		(Note a)	(Note d)	(Note j)	(Note e)	(Note i)	(Note i)	(Note g)	(Note f)	
Assets										
Current Assets										
Cash	$ 74	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 74
Accounts receivable	142									142
Deferred financial assets	20									20
Deferred taxes – current	5								(5)	–
Other current	5									5
	246	–	–	–	–	–	–	–	(5)	241
Exploration and evaluation assets	–	580								580
Property, plant and equipment, net	5,000	(580)								4,420
Goodwill	607		(130)							477
Other assets	50			39						89
Deferred financial assets	2									2
	5,659	–	(130)	39	–	–	–	–	–	5,568
	$ 5,905	$ –	$ (130)	$ 39	$ –	$ –	$ –	$ –	$ (5)	$ 5,809
Liabilities										
Current Liabilities										
Accounts Payable	$ 257									$ 257
Distributions payable to unitholders	32									32
Current portion of long term debt	37									37
Deferred financial credits	37									37
	363	–	–	–	–	–	–	–	–	363
Long term debt	522									522
Deferred financial credits	55									55
Decommissioning liability	230				155					385
Deferred income taxes	562			5	(42)				64	589
EELP units	–					56				56
TURIP	–						9			9
	1,369	–	–	5	113	56	9	–	64	1,616
Equity										
Shareholders' capital	5,689					(113)				5,576
Contributed Surplus	26						(22)			4
Accumulated deficit	(1,460)		(130)	34	(113)	57	13	(82)	(69)	$ (1,750)
Accumulated other comprehensive income/(loss)	(82)							82		–
	4,173	–	(130)	34	(113)	(56)	(9)	–	(69)	3,830
	$ 5,905	$ –	$ (130)	$ 39	$ –	$ –	$ –	$ –	$ (5)	$ 5,809

Consolidated Balance Sheet

As at June 30, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments Pre-exploration	E&E	DD&A	Impairment	Assets Held for Sale	Asset Dispositions	Decommissioning Liability	EELP Units	TURIP	Other Assets	Foreign Exchange	G&A	Transaction Costs	Income Tax	IFRS
		(Note a)	(Note a)	(Note b)	(Note d)	(Note n)	(Note c)	(Note e)	(Note i)	(Note i)	(Note g)	(Note h)	(Note k)	(Note f)		
Assets																
Current Assets																
Cash	$ 1	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –		$ 1
Accounts receivable	133					(5)										128
Assets held for sale	–					165										165
Deferred financial assets	45															45
Other current	8															8
	187	–	–	–	–	160	–	–	–	–	–	–	–	–	–	347
Exploration & evaluation assets	–		999										3			1,002
Property, plant & equipment, net	5,044	(1)	(999)	81	(40)	(160)	59	34					(10)			4,008
Goodwill	609				(418)		(1)									190
Other assets	51										89					140
Deferred financial assets	3													5		8
	5,707	(1)	–	81	(458)	(160)	58	34	–	–	89	–	(7)	5	–	5,348
	$ 5,894	$ (1)	$ –	$ 81	$ (458)	$ –	$ 58	$ 34	$ –	$ –	$ 89	$ –	$ (7)	$ 5	$ –	$ 5,695
Liabilities																
Current Liabilities																
Accounts Payable	$ 236					$ (3)										$ 233
Distributions payable	32															32
Current portion of long term debt	49															49
Liabilities held for sale	–					15										15
Deferred income taxes	7														(7)	–
Deferred financial credits	15															15
	339	–	–	–	–	12	–	–	–	–	–	–	–	–	(7)	344
Long term debt	649															649
Deferred financial credits	39															39
Decommissioning liability	216					(12)		189								393
Deferred income taxes	531			22	(10)		17	(42)			12		(1)		76	605
	1,435	–	–	22	(10)	(12)	17	147	–	–	12	–	(1)	–	76	1,686
EELP units	–								35							35
TURIP	–									8						8
	$ 1,774	$ –	$ –	$ 22	$ (10)	$ –	$ 17	$ 147	$ 35	$ 8	$ 12	$ –	$ (1)	$ –	$ 69	$ 2,073
Equity																
Shareholders' capital	5,703								(91)							5,612
Contributed surplus	28									(24)						4
Accumulated deficit	(1,541)	(1)		58	(448)		41	(113)	56	16	34	(82)	(6)	5	(69)	$ (2,050)
Accumulated other comprehensive income/(loss)	(70)			1							43	82				56
	4,120	(1)	–	59	(448)	–	41	(113)	(35)	(8)	77	–	(6)	5	(69)	3,622
	$ 5,894	$ (1)	$ –	$ 81	$ (458)	$ –	$ 58	$ 34	$ –	$ –	$ 89	$ –	$ (7)	$ 5	$ –	$ 5,695

Consolidated Balance Sheet

As at December 31, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments Pre-exploration	E&E	DD&A	Impairment	Asset Dispositions	Other Assets	Decommissioning Liability	EELP Units	TURIP	Foreign Exchange	G&A	Transaction Costs	Income Tax	IFRS
		(Note a)	(Note a)	(Note b)	(Note d)	(Note c)	(Note j)	(Note e)	(Note i)	(Note i)	(Note g)	(Note h)	(Note k)	(Note f)	
Assets															
Current Assets															
Cash	$ 8	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 8
Accounts receivable	126														126
Deferred financial assets	12														12
Deferred tax – current	11													(11)	–
Other current	50														50
	207	–	–	–	–	–	–	–	–	–	–	–	–	(11)	196
Exploration & evaluation assets	–	(1)	1,810		(11)	(261)						8			1,545
Property, plant & equipment, net	4,977	–	(1,810)	170	(378)	473		28				(19)			3,441
Goodwill	600				(447)	(1)									152
Deferred financial assets	–												4		4
Other assets	51						99								150
	5,628	(1)	–	170	(836)	211	99	28	–	–	–	(11)	4	–	5,292
	$ 5,835	$ (1)	$ –	$ 170	$ (836)	$ 211	$ 99	$ 28	$ –	$ –	$ –	$ (11)	$ 4	$ (11)	$ 5,488
Liabilities															
Current Liabilities															
Accounts Payable	$ 351														$ 351
Distributions payable	32														32
Current portion of long-term debt	46														46
Deferred financial credits	56														56
	485	–	–	–	–	–	–	–	–	–	–	–	–	–	485
Long-term debt	686														686
Deferred financial credits	47														47
Decommissioning liability	209							183							392
Deferred income taxes	503			27	(101)	54	12	(42)				(3)	1	34	485
EELP units	–								44						44
TURIP	–									20					20
	$ 1,445	$ –	$ –	$ 27	$ (101)	$ 54	$ 12	$ 141	$ 44	$ 20	$ –	$ (3)	$ 1	$ 34	$ 1,674
Equity															
Shareholders' capital	5,728								(89)						5,639
Contributed surplus	29									(25)					4
Accumulated deficit	(1,717)	(1)		143	(735)	157	34	(113)	45	5	(82)	(8)	3	(45)	$ (2,314)
Accumulated other comprehensive income/(loss)	(135)						53				82				–
	3,905	(1)	–	143	(735)	157	87	(113)	(44)	(20)	–	(8)	3	(45)	3,329
	$ 5,835	$ (1)	$ –	$ 170	$ (836)	$ 211	$ 99	$ 28	$ –	$ –	$ –	$ (11)	$ 4	$ (11)	$ 5,488

Consolidated Income Statement

Three months ended June 30, 2010 Unaudited (CDN $ millions, except per unit amounts)	Previous GAAP	IFRS Adjustments Pre-exploration	DD&A	Impairment	Asset Dispositions	Decommissioning Liability	EELP Units	TURIP	G&A	Transaction Costs	IFRS
		(Note a)	(Note b)	(Note d)	(Note c)	(Note e)	(Note i)	(Note i)	(Note h)	(Note k)	
Oil and gas sales	$ 325	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 325
Royalties	(57)										(57)
Commodity derivative instruments	33										33
Revenues	$ 301	–	–	–	–	–	–	–	–	–	$ 301
Expenses											
Operating costs	76										76
General and administrative	14							(2)	6		18
Transportation	7										7
Finance expense	16					3	(1)			(5)	13
Foreign exchange (gain) loss, net	13										13
Impairment expense	–			30							30
Depreciation, depletion & amortization	165		(43)			(3)					119
Other (income)/expense	–				(58)						(58)
	291	–	(43)	30	(58)	–	(1)	(2)	6	(5)	218
Net income/(loss) before income tax	10	–	43	(30)	58	–	1	2	(6)	5	83
Current tax expense /(recovery)	–										–
Deferred income tax expense/(recovery)	(21)	–	12	–	17	–	–	–	(1)	–	7
Net income/(loss)	$ 31	$ –	$ 31	$ (30)	$ 41	$ –	$ 1	$ 2	$ (5)	$ 5	$ 76

Net Income/(Loss) per Share (Note m)

	Previous GAAP	IFRS
Basic	$ 0.18	$ 0.44
Diluted	$ 0.18	$ 0.42

Consolidated Statement of Comprehensive Income

Three months ended June 30, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments Pre-exploration	DD&A	Impairment	Asset Dispositions	Other Assets	EELP Units	TURIP	G&A	Transaction Costs	IFRS
		(Note a)	(Note b)	(Note d)	(Note c)	(Note j)	(Note i)	(Note i)	(Note h)	(Note k)	
Net income/(loss)	$ 31	$ –	$ 31	$ (30)	$ 41	$ –	$ 1	$ 2	$ (5)	$ 5	$ 76
Other comprehensive income, net of tax											
Change in cumulative translation adjustment	39		1								40
Unrealized gain on marketable securities						6					6
Comprehensive income/(loss)	$ 70	$ –	$ 32	$ (30)	$ 41	$ 6	$ 1	$ 2	$ (5)	$ 5	$ 122

Consolidated Income Statement

Six months ended June 30, 2010 Unaudited (CDN $ millions, except per unit amounts)	Previous GAAP	IFRS Adjustments Pre-exploration	DD&A	Impair-ment	Asset Dispositions	Decommis-sioning Liability	EELP Units	TURIP	G&A	Transaction Costs	IFRS
		(Note a)	(Note b)	(Note d)	(Note c)	(Note e)	(Note i)	(Note i)	(Note h)	(Note k)	
Oil and gas sales	$ 695	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 695
Royalties	(122)										(122)
Commodity derivative instruments	66										66
Revenues	$ 639	–	–	–	–	–	–	–	–	–	$ 639
Expenses											
Operating costs	152										152
General and administrative	34							(3)	7		38
Transportation	13										13
Finance expense	23					7	1			(5)	26
Foreign exchange (gain) loss, net	3										3
Impairment expense	–			328							328
Depreciation, depletion & amortization	324		(80)			(7)					237
Other (income)/expense	–	1			(58)						(57)
	549	1	(80)	328	(58)	–	1	(3)	7	(5)	740
Net income/(loss) before income tax	90	(1)	80	(328)	58	–	(1)	3	(7)	5	(101)
Current tax expense /(recovery)	–										–
Deferred income tax expense/(recovery)	(21)	–	22	(10)	17	–	–	–	(1)	–	7
Net income/(loss)	$ 111	$ (1)	$ 58	$ (318)	$ 41	$ –	$ (1)	$ 3	$ (6)	$ 5	$ (108)

Net Income/(Loss) per Share (Note m)

	Previous GAAP	IFRS
Basic	$ 0.63	$ (0.61)
Diluted	$ 0.63	$ (0.61)

Consolidated Statement of Comprehensive Income

Six months ended June 30, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments Pre-exploration	DD&A	Impair-ment	Asset Dispositions	Other Assets	EELP Units	TURIP	G&A	Transaction Costs	IFRS
		(Note a)	(Note b)	(Note d)	(Note c)	(Note j)	(Note i)	(Note i)	(Note h)	(Note k)	
Net income/(loss)	$ 111	$ (1)	$ 58	$ (318)	$ 41	$ –	$ (1)	$ 3	$ (6)	$ 5	$ (108)
Other comprehensive income, net of tax											
Change in cumulative translation adjustment	12		1								13
Unrealized gain on marketable securities						43					43
Comprehensive income/(loss)	$ 123	$ (1)	$ 59	$ (318)	$ 41	$ 43	$ (1)	$ 3	$ (6)	$ 5	$ (52)

Consolidated Income Statement

Twelve months ended December 31, 2010 Unaudited (CDN $ millions, except per unit amounts)	Previous GAAP	IFRS Adjustments Pre-exploration	E&E	DD&A	Impairment	Asset Dispositions	Decommissioning Liability	EELP Units	TURIP	G&A	Transaction Costs	Income Tax	IFRS
		(Note a)	(Note a)	(Note b)	(Note d)	(Note c)	(Note e)	(Note i)	(Note i)	(Note h)	(Note k)	(Note f)	
Oil and Gas Sales	$ 1,327	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 1,327
Royalties	(223)												(223)
Commodity derivative instruments	24												24
Revenues	$ 1,128	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 1,128
Expenses													
Operating costs	290												290
General and administrative	79								8	11			98
Transportation	27												27
Finance expense	47						14	12			(4)		69
Foreign exchange (gain)/loss, net	(1)												(1)
Impairment expense	–				706								706
Depreciation, depletion and amortization	645			(170)			(14)						461
Other (income)/expense	(1)	1				(211)							(211)
	1,086	1	–	(170)	706	(211)	–	12	8	11	(4)	–	1,439
Net income/(loss) before income tax	$ 42	$ (1)	$ –	$ 170	$ (706)	$ 211	$ –	$ (12)	$ (8)	$ (11)	$ 4	–	$ (311)
Current tax expense/(recovery)	(30)												(30)
Deferred income tax expense/(recovery)	(55)			27	(101)	54				(3)	1	(24)	(101)
Net income/(loss)	$ 127	$ (1)	$ –	$ 143	$ (605)	$ 157	$ –	$ (12)	$ (8)	$ (8)	$ 3	$ 24	$ (180)

Net Income (Loss) per Share (Note m)

	Previous GAAP	IFRS
Basic	$ 0.72	$ (1.02)
Diluted	$ 0.71	$ (1.02)

Consolidated Statement of Comprehensive Income

Twelve months ended December 31, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments Pre-exploration	E&E	DD&A	Impairment	Asset Dispositions	Other Assets	EELP Units	TURIP	G&A	Transaction Costs	Income Tax	IFRS
		(Note a)	(Note a)	(Note b)	(Note d)	(Note c)	(Note j)	(Note i)	(Note i)	(Note h)	(Note k)	(Note f)	
Net income/(loss)	$ 127	(1)	–	143	(605)	157		(12)	(8)	(8)	3	24	$ (180)
Other comprehensive income, net of tax													
Change in cumulative translation adjustment	(53)												(53)
Unrealized gain on marketable securities							53						53
Comprehensive income/(loss)	$ 74	(1)	–	143	(605)	157	53	(12)	(8)	(8)	3	24	$ (180)

Consolidated Statement of Changes in Equity

Six months ended June 30, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments Pre-exploration	DD&A	Impairment	Asset Dispositions	Decommis-sioning Liability	EELP Units	TURIP	Other Assets	Foreign Exchange	G&A	Transaction Costs	Income Tax	IFRS
		(Note a)	(Note b)	(Note d)		(Note e)	(Note i)	(Note i)	(Note j)	(Note g)	(Note h)	(Note k)	(Note f)	
Trust Units														
Balance, beginning of year	$ 5,689	$ –	$ –	$ –	$ –	$ –	$ (113)	$ –	$ –	$ –	$ –	$ –	$ –	$ 5,576
Issued for cash:														
DRIP	11													11
Stock option plan	3													3
Non cash:														
Equivalent EELP units	–						22							22
Balance, end of period	$ 5,703	$ –	$ –	$ –	$ –	$ –	$ (91)	$ –	$ –	$ –	$ –	$ –	$ –	$ 5,612
Contributed Surplus														
Balance, beginning of year	$ 26	$ –	$ –	$ –	$ –	$ –	$ –	$ (22)	$ –	$ –	$ –	$ –	$ –	$ 4
Stock option plan – expensed	2							(2)						–
Balance, end of period	$ 28	$ –	$ –	$ –	$ –	$ –	$ –	$ (24)	$ –	$ –	$ –	$ –	$ –	$ 4
Accumulated Deficit														
Accumulated income, beginning of year	$ 3,265	$ –	$ –	$ (130)	$ –	$ (113)	$ 57	$ 13	$ 34	$ (82)	$ –	$ –	$ (69)	$ 2,975
Net income/(loss)	111	(1)	58	(318)	41	–	(1)	3	–	–	(6)	5	–	(108)
	3,376	(1)	58	(448)	41	(113)	56	16	34	(82)	(6)	5	(69)	2,867
Accumulated dividends, beginning of year	(4,725)													(4,725)
Dividends	(192)													(192)
	(4,917)													(4,917)
Balance, end of period	$ (1,541)	$ (1)	$ 58	$ (448)	$ 41	$ (113)	$ 56	$ 16	$ 34	$ (82)	$ (6)	$ 5	$ (69)	$ (2,050)
Accumulated Other Comprehensive Income														
Balance, beginning of year	$ (82)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 82	$ –	$ –	$ –	$ –
Change in cumulative translation adjustment	12		1											13
Unrealized gain on marketable securities	–								43					43
Balance, end of period	$ (70)	$ –	$ 1	$ –	$ –	$ –	$ –	$ –	$ 43	$ 82	$ –	$ –	$ –	$ 56
Total Equity	$ 4,120	$ (1)	$ 59	$ (448)	$ 41	$ (113)	$ (35)	$ (8)	$ 77	$ –	$ (6)	$ 5	$ (69)	$ 3,622

Consolidated Statement of Changes in Equity

Twelve months ended December 31, 2010 Unaudited (CDN $ millions)	Previous GAAP	Pre-exploration	DD&A	Impairment	Asset Dispositions	Decommissioning Liability	EELP Units	TURIP	Other Assets	Foreign Exchange	G&A	Income Tax	Transaction Costs	IFRS
		IFRS Adjustments												
		(Note a)	(Note b)	(Note d)	(Note c)	(Note e)	(Note i)	(Note i)	(Note j)	(Note g)	(Note h)	(Note f)	(Note k)	
Trust Units														
Balance, beginning of year	$ 5,689	$ –	$ –	$ –	$ –	$ –	$ (113)	$ –	$ –	$ –	$ –	$ –	$ –	$ 5,576
Issued for cash:														
DRIP	29													29
Stock option plan	7													7
Non cash:														
Stock option plan	2							1						3
Equivalent EELPs	–						24							24
Balance, end of year	$ 5,727	$ –	$ –	$ –	$ –	$ –	$ (89)	$ 1	$ –	$ –	$ –	$ –	$ –	$ 5,639
Contributed Surplus														
Balance, beginning of year	$ 26	$ –	$ –	$ –	$ –	$ –	$ –	$ (22)	$ –	$ –	$ –	$ –	$ –	$ 4
Stock option plan (non-cash) – exercised	(2)							1						(1)
Stock option plan (non-cash) – expensed	6							(5)						1
Balance, end of year	$ 30	$ –	$ –	$ –	$ –	$ –	$ –	$ (26)	$ –	$ –	$ –	$ –	$ –	$ 4
Accumulated Deficit														
Accumulated income, beginning of year	$ 3,265	$ –	$ –	$ (130)	$ –	$ (113)	$ 57	$ 13	$ 34	$ (82)	$ –	$ (69)	$ –	$ 2,975
Net income/(loss)	127	$ (1)	143	(605)	157	–	(12)	(8)	–	–	(8)	24	3	(180)
	3,392	(1)	143	(735)	157	(113)	45	5	34	(82)	(8)	(45)	3	2,795
Accumulated dividends, beginning of year	(4,725)													(4,725)
Dividends	(384)													(384)
	(5,109)													(5,109)
Balance, end of year	$ (1,717)	$ (1)	$ 143	$ (735)	$ 157	$ (113)	$ 45	$ 5	$ 34	$ (82)	$ (8)	$ (45)	$ 3	$ (2,314)
Accumulated Other Comprehensive Income														
Balance, beginning of year	$ (82)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 82	$ –	$ –	$ –	$ –
Change in cumulative translation adjustment	(53)													(53)
Unrealized gain on marketable securities	–								53					53
Balance, end of year	$ (135)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 53	$ 82	$ –	$ –	$ –	$ –
Total Equity	$ 3,905	$ (1)	$ 143	$ (735)	$ 157	$ (113)	$ (44)	$ (20)	$ 87	$ –	$ (8)	$ (45)	$ 3	$ 3,329

The following discussion explains the significant differences between Enerplus' Canadian GAAP accounting policies and those applied by Enerplus under IFRS. IFRS policies have been retrospectively and consistently applied except where the IFRS 1 mandatory and optional exemptions detailed above permitted an alternative treatment.

IFRS ADJUSTMENTS

a) Property, Plant and Equipment

Under IFRS capital costs are recorded using one of the following three categories:

i) Pre-Exploration Costs ("Pre-E&E")

Under Canadian GAAP costs incurred prior to having obtained the legal right to explore were capitalized and included in PP&E using the full cost method of accounting. Under IFRS such expenditures are expensed as incurred.

These costs were approximately $1.1 million for the periods ended June 30, 2010 and December 31, 2010.

ii) E&E Assets

Under Canadian GAAP E&E assets were capitalized using the full cost method of accounting and included in PP&E. Under IFRS E&E assets are early stage assets that management has not fully evaluated for technical feasibility and commercial viability. IFRS requires E&E assets to be separately recognized on the face of the balance sheet and these costs are not subject to depletion. Under IFRS these capitalized costs are transferred from E&E assets to PP&E assets once technical feasibility and commercial viability has been determined.

At January 1, 2010 approximately $580 million of assets were recognized on the Consolidated Balance Sheet as E&E assets. The balance is comprised primarily of Enerplus' Kirby oil sands asset, prior to its disposition on October 1, 2010, and undeveloped lands in Canada and the U.S. As at June 30, 2010 and December 31, 2010 Enerplus' E&E assets were $1,002 million and $1,545 million respectively. No E&E assets were transferred to PP&E during 2010.

iii) D&P Assets

Under Canadian GAAP D&P assets were capitalized using the full cost method of accounting and included in PP&E. Under IFRS D&P assets are accounted for in smaller cost centers, or CGUs and continue to be recognized on the Consolidated Balance Sheet as part of PP&E.

Using the IFRS 1 exemption available to companies previously using the Canadian GAAP full cost accounting guideline, the cost of net PP&E was $4,420 million on the date of transition to IFRS. The historic net oil and gas PP&E values were allocated to CGUs based on the attributed value of proved plus probable reserves at December 31, 2009. As at June 30, 2010 and December 31, 2010 PP&E was $4,008 million and $3,441 million respectively.

On transition to IFRS Enerplus allocated the consolidated goodwill balance which was generated from historic business combinations to the CGUs that benefited from the synergies of the combination.

b) Depletion, Depreciation and Amortization

At January 1, 2010 accumulated depletion was set to zero in conjunction with the IFRS 1 exemption that allowed companies to allocate their historic net oil and gas PP&E values to CGUs.

Under Canadian GAAP depletion was calculated on a unit of production basis using proved reserves on a country by country basis. Under IFRS Enerplus depletes D&P assets on a CGU basis using proved plus probable reserves. This change reduced DD&A by approximately $43 million and $80 million for the three and six months ended June 30, 2010 respectively, and $170 million for the year ended December 31, 2010.

c) Asset Dispositions

Under Canadian GAAP full cost accounting gains and losses were not recognized upon disposition of oil and gas assets unless such a disposition altered the rate of depletion by 20% or more. Under IFRS gains and losses are recognized based on the difference between the proceeds from disposition and the asset's net carrying value.

For the three and six months ended June 30, 2010 Enerplus recognized gains of $58 million. For the year ended December 31, 2010 Enerplus recognized gains of $211 million. There were no gains recognized under Canadian GAAP during these periods.

d) Impairment

E&E assets

Under Canadian GAAP E&E assets were tested for impairment by comparing their recoverable amount to the carrying value as part of the entire PP&E full cost pool. Under IFRS E&E assets are subject to an assessment for impairment where indicators of impairment exist. The E&E asset impairment test compares the carrying value to the sum of the assets' fair value plus any excess of the D&P assets' recoverable amount over their carrying value on a country by country basis.

Where an E&E asset is determined to be technically feasible and commercially viable, the accumulated costs are transferred to D&P assets. When an area is determined not be to technically feasible and commercially viable, the unrecoverable costs are charged to net income.

As at January 1, 2010 there was no impairment on Enerplus' E&E assets. For the period ending December 31, 2010 Enerplus recorded impairment of $11 million on its E&E assets. During the same period under Canadian GAAP there were no impairments recorded.

D&P assets

Under IFRS testing for D&P asset impairments is completed at a CGU level compared to a country by country basis utilizing the full cost accounting guideline under Canadian GAAP. When indicators of impairment exist, the carrying value of each CGU, including goodwill, is compared to its recoverable amount which is defined as the higher of its FVLCTS or VIU. Where the carrying value exceeds the recoverable amount an impairment loss exists. Impairment losses are first recorded against goodwill within a CGU and the remainder is recorded against the D&P assets.

As at January 1, 2010 no impairments were recorded on Enerplus' D&P assets. For the three and six months ended June 30, 2010 D&P impairments of approximately $3 million and $40 million respectively were recognized. For the year ended December 31, 2010 D&P asset impairments of approximately $378 million were recognized. The impairments related to Enerplus' natural gas focused CGUs and were the result of lower forward natural gas prices.

Goodwill

Under Canadian GAAP goodwill was carried on a consolidated basis and was assessed for impairment when indicators of impairment existed, or at least annually.

On transition to IFRS Enerplus allocated the consolidated goodwill balance which was generated from historic business combinations to the CGUs that benefited from the synergies of the combination.

At the date of transition, January 1, 2010, Enerplus recognized a goodwill impairment of $130 million. For the three and six months ended June 30, 2010 goodwill impairments of $27 million and $288 million respectively, were recognized. For the year ended December 31, 2010, goodwill impairments of approximately $317 million were recognized. All impairments recognized were a result of lower forward natural gas prices.

Reversals of impairment

The reversal of impairment losses on PP&E was not permitted under Canadian GAAP. Under IFRS impairment losses previously recorded are reversed if the conditions giving rise to the impairment have reversed. There were no reversals of impairment during 2010.

Goodwill impairments are not reversed in future periods under IFRS, which is consistent with Canadian GAAP.

e) Decommissioning Liabilities

Under Canadian GAAP and IFRS the estimated fair value of the future cash outflows associated with abandoning, reclaiming and remediating PP&E assets are recorded on the balance sheet. Under Canadian GAAP the estimates of future cash outflows were discounted using a credit adjusted risk-free rate whereas under IFRS a risk-free rate is used. Additionally, accretion expense under IFRS is classified as a finance expense whereas under Canadian GAAP it was included within DD&A.

At January 1, 2010 an increase of approximately $155 million was recorded to the decommissioning liability. In accordance with the IFRS 1 exemption for full cost oil and gas companies the offset of $113 million, net of tax, was recorded to accumulated deficit. Subsequent remeasurement of the decommissioning liability is recorded through PP&E.

For the three and six months ended June 30, 2010 and the year ended December 31, 2010 approximately $3 million, $7 million and $14 million of accretion was reclassified from DD&A to finance expense under IFRS respectively.

f) Deferred Income Tax

Prior to the conversion to a corporation, Enerplus' income trust structure resulted in a higher deferred tax rate which increased the deferred tax liability under IFRS by approximately $69 million at the date of transition. Approximately $34 million of this increase reversed on January 1, 2011 upon conversion to a corporation with a corresponding credit to income.

IFRS also requires all deferred taxes to be classified as long term.

g) Foreign Currency Translation

Upon adoption of IFRS Enerplus utilized an exemption that enabled the cumulative translation adjustment ("CTA") balance to be set to zero rather than having to retroactively restate the CTA. As at June 30, 2010 and December 31, 2010 CTA recognized in other comprehensive income under IFRS was approximately $13 million and $53 million respectively.

h) General and Administrative

For the three and six months ended June 30, 2010 and year ended December 31, 2010 Enerplus reduced its capitalized G&A by approximately $6 million, $7 million and $11 million respectively, resulting in a higher G&A expense. This reduction is primarily a result of capitalizing fewer G&A expenses associated with acquisition and divestiture activities under IFRS compared to Canadian GAAP.

i) EELP Units and TURIP

Under Enerplus' former trust indenture outstanding trust units were redeemable at the option of the holder at 85% of the current trading price. Under Canadian GAAP Enerplus' trust units and EELP units were considered permanent equity and included within Shareholders' Capital. Under IFRS Enerplus' trust units are considered puttable financial instruments, however a specific exemption for trust units allows them to be classified as permanent equity. This exemption does not apply to instruments that are convertible into trust units such as the EELP units and trust unit rights. As a result, IFRS requires the EELP units and trust unit rights to be reported as liabilities at their fair value with changes in fair value recorded to income. As EELP units are converted to trust units by unitholders, the associated liability is recorded to unitholders' capital. As rights are exercised, the proceeds, together with the amount recorded as a trust unit rights liability, are recorded to unitholders' capital.

On January 1, 2010 Enerplus recorded a $56 million liability representing the redemption value of the outstanding EELP units along with a $113 million reduction to Shareholders' Capital and $57 million decrease to accumulated deficit to retroactively adjust for the impact of the EELP units. As at June 30, 2010 and December 31, 2010 the fair value of the EELP liability was $35 million and $44 million respectively.

A trust unit rights liability of $9 million was recorded on January 1, 2010, representing the TURIP fair value determined using a binomial lattice option pricing model on that date. In conjunction with the liability a reduction of $22 million was recognized in Shareholders' Capital with an offsetting credit of $13 million to accumulated deficit. As at June 30, 2010 and December 31, 2010 the fair value of the TURIP liability was $8 million and $20 million respectively.

j) Other Assets

Under Canadian GAAP investments in non-publicly traded securities are carried at cost. Under IFRS all securities, publicly or privately held, must be carried at fair value and revalued at each reporting date.

As at January 1, 2010 Enerplus recorded an increase in other assets of approximately $39 million with the offset recorded to accumulated deficit.

For the six months ended June 30, 2010 and the year ended December 31, 2010 Enerplus' increases in the fair value of investments of $50 million ($43 million net of tax) and $60 million ($53 million net of tax) respectively were reported. These changes were recorded to other comprehensive income, net of tax.

k) Transaction Costs

During the second quarter 2010 Enerplus renewed its bank credit facility and incurred a $5 million extension fee that was expensed under Canadian GAAP.

Under IFRS these transaction costs are capitalized and amortized to finance expense over the term of the facility. For the three and six months ended June 30, 2010 amortization of these transactions costs was nil. For the year ended December 31, 2010 Enerplus recorded amortization costs of approximately $1 million.

l) Business Combinations

Acquisitions prior to January 1, 2010

As part of its transition to IFRS Enerplus elected to restate only those business combinations that occurred on or after January 1, 2010. In respect of acquisitions prior to January 1, 2010 goodwill represents the amount recognized under previous Canadian GAAP, however the goodwill generated from historic business combinations was allocated to the CGUs that benefited from the synergies of the combination.

Transaction costs, other than those associated with the issue of debt or equity securities, that Enerplus incurs in connection with a business combination are expensed as incurred.

m) Net Income Per Share

The following table summarizes the weighted average shares outstanding after re-classification of the EELP units and TURIP:

(millions)	Three months ended June 30, 2010	Six months ended June 30, 2010	Twelve months ended December 31, 2010
Weighted average shares outstanding			
Basic	176	174	176
Diluted	178	177	178

n) Assets Classified as held for sale

Under Canadian GAAP companies who follow full cost accounting are not required to present separately assets held for sale if the disposal of the assets would not change the depletion rate by more than 20 per cent.

Under IFRS, a non-current asset must be classified as held for sale if its carrying amount will be recovered primarily through a sale transaction rather than continuing use. Assets held for sale are recorded at the lower of their carrying value or fair value less cost to sell.

At June 30, 2010 Enerplus reported assets held for sale of $165 million, including $5 million of accounts receivable. Enerplus also recorded liabilities held for sale of $15 million, of which $3 million related to accounts payable and $12 million related to decommissioning liabilities. There were no assets or liabilities held for sale at December 31, 2010.

BOARD OF DIRECTORS

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Houston, Texas

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Corporate Director
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Corporate Director
Calgary, Alberta

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

Susan M. MacKenzie(7)(9)
Corporate Director
Calgary, Alberta

David O'Brien(3)
Corporate Director
Calgary, Alberta

Elliott Pew(5)(7)
Corporate Director
Boerne, Texas

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Corporate Director
Canmore, Alberta

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Seth Consultants Ltd.
Calgary, Alberta

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Corporate Director
Calgary, Alberta

Clayton Woitas(7)(11)
President
Range Royalty Management Ltd.
Calgary, Alberta

Robert L. Zorich(10)
Managing Director
EnCap Investments L.P.
Houston, Texas

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

OFFICERS

ENERPLUS CORPORATION

Gordon J. Kerr
President & Chief Executive Officer

Ian C. Dundas
Executive Vice President & Chief Operating Officer

Ray J. Daniels
Senior Vice President, Canadian Operations

Eric G. Le Dain
Senior Vice President, Strategic Planning, Reserves, & Marketing

Robert J. Waters
Senior Vice President & Chief Financial Officer

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

Rodney D. Gray
Vice President, Finance

Robert A. Kehrig
Vice President, Resource Development

Jennifer F. Koury
Vice President, Corporate Services

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

Patrick "Scott" Walsh
Vice-President, Information Systems

Kenneth W. Young
Vice President, Land

Jodine J. Jenson Labrie
Controller, Finance

ENERPLUS RESOURCES (USA) CORPORATION

Dana W. Johnson
President

CORPORATE INFORMATION

Operating Companies Owned by Enerplus Corporation

Enerplus Partnership
Enerplus Resources (USA) Corporation

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
Deloitte & Touche LLP
Calgary, Alberta

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

U.S. Co-Transfer Agent
Computershare Trust Company, N.A.
Golden, Colorado

Independent Reserve Engineers
McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Haas Petroleum Engineering Services, Inc.
Dallas, Texas

Stock Exchange Listings and Trading Symbols
Toronto Stock Exchange: ERF
New York Stock Exchange: ERF

U.S. Office
950 17th Street, Suite 2200
Denver, CO 80202

Telephone: 720.279.5500
Fax: 720.279.5550

ABBREVIATIONS

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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

AOCI accumulated other comprehensive income

API American Petroleum Institute

bbl(s)/day barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons

Bcf billion cubic feet

Bcfe billion cubic feet equivalent

CBM coalbed methane, otherwise known as natural gas from coal – NGC

COGPE Canadian oil and gas property expense

CTA cumulative translation adjustment

D&P developed and producing

E&E exploration and evaluation

F&D Costs finding and development costs

FD&A Costs finding, development and acquisition costs

FDC future development capital

HH "Henry Hub" a reference to the physical storage and trading hub in Louisiana which is the delivery point for the NYMEX Natural Gas contract

IFRS International Financial Reporting Standards

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent

Mcf thousand cubic feet

Mcfe thousand cubic feet equivalent

Mcf/day thousand cubic feet per day

Mcfe/day thousand cubic feet equivalent per day

MMbbl(s) million barrels

MMBOE million barrels of oil equivalent

MMBtu million British Thermal Units

MMBtu/day million British Thermal Units per day

MMcf million cubic feet

MMcf/day million cubic feet per day

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 reserve reporting in Canada)

OCI other comprehensive income

P+P Reserves proved plus probable reserves

PDP Reserves proved developed producing reserves

RLI reserve life index

WI percentage working interest ownership

WTI West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing purposes enerPLUS

The Dome Tower
3000, 333 – 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

Tel. 403.298.2200
Toll Free 1.800.319.6462
Fax 403.298.2211
investorrelations@enerplus.com

www.enerplus.com

ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE