enerPLUS

THIRD QUARTER REPORT

NINE MONTHS ENDED SEPTEMBER 30, 2011

SELECTED FINANCIAL RESULTS	Three months ended September 30,		Nine months ended September 30,	
	2011	2010[1]	2011	2010[1]
Financial (000's)				
Funds Flow[2]	**$ 123,262**	$ 193,328	**$ 416,927**	$ 566,363
Dividends to Shareholders	**97,416**	96,111	**291,179**	287,732
Net Income/(Loss)	**111,321**	(136,261)	**408,852**	(243,781)
Debt Outstanding – net of cash	**734,300**	680,264	**734,300**	680,264
Capital Spending	**201,266**	129,945	**520,875**	312,501
Property and Land Acquisitions	**67,313**	139,678	**209,946**	489,425
Divestments	**7,320**	150,747	**638,108**	333,523
Financial per Weighted Average Shares Outstanding				
Funds Flow[2]	**$ 0.68**	$ 1.10	**$ 2.32**	$ 3.23
Dividends	**0.54**	0.55	**1.62**	1.64
Net Income/(Loss)	**0.62**	(0.77)	**2.28**	(1.39)
Weighted Average Number of Shares Outstanding	**180,266**	176,075	**179,566**	175,430
Debt to Trailing 12 Month Funds Flow[5]	**1.3x**	1.2x	**1.3x**	1.2x
Selected Financial Results per BOE[3]				
Oil & Gas Sales[4]	**$ 46.44**	$ 40.08	**$ 48.34**	$ 42.96
Royalties	**(8.33)**	(7.29)	**(8.67)**	(7.74)
Commodity Derivative Instruments	**(0.66)**	2.76	**(1.09)**	1.84
Operating Costs	**(10.90)**	(10.08)	**(9.87)**	(10.05)
General and Administrative	**(2.45)**	(2.65)	**(2.96)**	(2.53)
Interest and Other Expenses	**(1.01)**	(1.88)	**(1.55)**	(1.28)
Taxes	**(4.80)**	4.42	**(3.75)**	1.45
Funds Flow[2]	**$ 18.29**	$ 25.36	**$ 20.45**	$ 24.65

SELECTED OPERATING RESULTS	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Average Daily Production				
Natural gas (Mcf/day)	**243,675**	285,292	**250,244**	293,543
Crude oil (bbls/day)	**29,337**	31,639	**29,665**	31,393
NGLs (bbls/day)	**3,295**	3,681	**3,323**	3,842
Total (BOE/day)	**73,245**	82,869	**74,695**	84,159
% Natural gas	**55%**	57%	**56%**	58%
Average Selling Price[4]				
Natural gas (per Mcf)	**$ 3.73**	$ 3.67	**$ 3.83**	$ 4.19
Crude oil (per bbl)	**77.57**	66.97	**82.01**	69.80
NGLs (per bbl)	**64.98**	46.69	**63.89**	50.61
US/CDN exchange rate	**1.02**	0.96	**1.02**	0.97
Net Wells drilled	**35**	25	**75**	184

(1) 2010 comparative amounts have been restated and are presented in accordance with International Financial Reporting Standards ("IFRS") and 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.
(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 month trailing funds flow for September 30, 2010, includes funds flow for October through December 2009 which was prepared following previous Canadian GAAP.

Share Trading Summary **For the three months ended September 30, 2011**	**CDN* – ERF** (CDN$)	**U.S.** – ERF** (US$)
High	$ 30.75	$ 31.99
Low	$ 25.13	$ 24.41
Close	$ 25.87	$ 24.54

* 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**
Second Quarter Total	**$ 0.54**	**$ 0.55**
July	$ 0.18	$ 0.19
August	0.18	0.18
September	0.18	0.18
Third Quarter Total	**$ 0.54**	**$ 0.55**
Total Year-to-Date	**$ 1.62**	**$ 1.65**

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.

PRESIDENT'S MESSAGE

As weather conditions improved during the third quarter of 2011, our operations and drilling activities resumed, albeit at a slower pace than anticipated. We continued to be impacted by road bans and restricted access to our leases early in the quarter, particularly in the North Dakota region, delaying our drilling and completions activity in this key growth area.

Daily production volumes averaged 73,245 BOE/day during the quarter which was approximately 3% lower than expected. Production volumes reflected those delays as well as the strategic sale of a portion of our Marcellus acreage which occurred at the end of June. Year-to-date, we've brought 48 net wells on stream, just over half of the on-streams we had planned for 2011. During the fourth quarter, we expect to bring an additional 41 net wells on stream, approximately 90% of which are oil wells. As a result of this activity, we expect to achieve our exit production target of 81,000 – 84,000 BOE/day. With the slower than expected build in production through the first nine months of the year, we expect our full year production will average close to 76,000 BOE/day in 2011.

Our drilling activities to date have been very encouraging, particularly in a number of core areas for us. Our first Three Forks test well at Fort Berthold, North Dakota has come on stream with a 30 day initial production rate of approximately 830 bbls/day and our first operated Marcellus well has tested significantly above expectations with a 24 hour peak test rate of 8.3 MMcf/day. We've also experienced positive results in the Ratcliffe and the Viking in Saskatchewan and recently completed a Bluesky delineation well at Ansell which tested at 4.2 MMcf/day. Overall, our drilling program is delivering at or above our expectations, just slightly behind the anticipated timeline.

We continue to add to our portfolio of undeveloped land in both Canada and the U.S. to build a solid inventory of future growth opportunities. Since the second quarter, we've added another 38,000 acres of land targeting the liquids-rich natural gas Duvernay play in the Willesden Green area and now hold approximately 100 sections of undeveloped land in the Duvernay. We expect to drill our first test well in 2012. We also acquired additional acreage in our emerging oil play portfolio and now hold approximately 25,000 acres in these prospects in Canada along with our 75,000 net acres in the Bakken/Three Forks play in Fort Berthold, North Dakota. In addition, we own over 110,000 net acres in the Marcellus (60% operated), over 33,000 net acres in the Montney, and over 67,000 net acres in the Stacked Mannville region of Alberta. Year-to-date, we've invested just over $100 million adding new growth positions in Canada. Our strategic land position now includes over 380,000 net acres in some of the most prospective oil and gas plays in North America that will support reserves, production and cash flow growth in the coming years.

Our operations generated $123 million of funds flow ($0.68/share) during the quarter, net of current taxes of $32 million related to our Marcellus disposition and adjustments to prior year tax estimates. Excluding these taxes, our funds flow would have been approximately $155 million ($0.86/share). As planned, our balance sheet helped support our development capital spending program in the quarter. We remain in a very solid financial position with only $265 million drawn on our $1 billion credit facility and a debt to funds flow ratio of 1.3x at the end of the quarter. We continue to actively hedge our exposure to oil prices to help protect our cash flow and retain our financial strength. We currently have over 50% of our expected oil production in 2012 hedged at approximately $95/bbl and have started to add hedge positions for our 2013 oil production as well. Our gas production remains unhedged at this time as the benefit of locking in prices in a weak forward market remains limited.

PRODUCTION AND CAPITAL SPENDING

Our base production, primarily from our Canadian operations, continued to deliver consistent production through the third quarter of 2011. Oil and liquids volumes from both our Bakken/tight oil and waterflood assets were up slightly over the second quarter despite delays and our total oil and liquids production represented 45% of total production during the quarter. Our conventional natural gas production continued to decline, as expected, due to low capital spending levels in a low price environment. Our Marcellus production was lower as a result of the sale of a portion of mainly non-operated assets in this resource play. We invested just over $200 million of capital during the third quarter of 2011, drilling approximately 35 net wells and bringing 12 net wells on-stream. Approximately 80% of our wells were oil wells and all but one were horizontal wells. Over 85% of our spending was directed to our Bakken, waterflood and Marcellus resource plays.

During the fourth quarter we expect to see a significant increase in production as a result of completion and tie-in activities, primarily in the U.S. At Fort Berthold we expect to bring 13 wells on-stream in November and December, nine Bakken and four Three Forks short horizontal wells. We also expect to add incremental production associated with field optimization activities. As a result of these activities, we expect production to grow by 5,000 – 8,000 BOE/day net by the end of December. In the Marcellus, tie-in activities by our operators are expected to accelerate in the fourth quarter with exit production in the range of 25 MMcf/day – 33 MMcf/day net to Enerplus. We expect approximately 24 additional gross wells in the Marcellus region (2.3 net wells) to come on-stream by year-end. In Canada, we plan to have approximately 23 net wells on-stream in the fourth quarter primarily in our crude oil waterflood properties targeting the Ratcliffe, Lodgepole and Viking formations. We also plan to test both the Montney and Stacked Mannville areas of the Deep Basin before year-end.

PRODUCTION & CAPITAL SPENDING

	Three months ended September 30, 2011		Nine months ended September 30, 2011	
Play Type	**Average Production Volumes**	**Capital Spending ($ millions)**	**Average Production Volumes**	**Capital Spending ($ millions)**
Bakken/Tight Oil (BOE/day)	13,511	90	13,284	222
Crude Oil Waterfloods Oil (BOE/day)	13,462	33	13,404	79
Conventional Oil (BOE/day)	5,738	6	6,057	13
Total Oil (BOE/day)	32,711	129	32,745	314
Marcellus Shale Gas (Mcfe/day)	15,025	50	19,365	140
Other Natural Gas (Mcfe/day)	228,177	22	232,337	67
Total Gas (Mcfe/day)	243,202	72	251,702	207
Company Total	73,245	201	74,695	521

NET DRILLING ACTIVITY – For the three months ended September 30, 2011

Play Type	Horizontal Wells Drilled	Vertical Wells Drilled	Total Wells Drilled	Wells Pending Completion/ Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Bakken/Tight Oil	12.3	1.0	13.3	10.8	6.9	–
Crude Oil Waterfloods	14.1	–	14.1	12.1	2.4	–
Conventional Oil	0.6	–	0.6	0.3	0.7	–
Total Oil	**27.0**	**1.0**	**28.0**	**23.2**	**10.0**	**–**
Marcellus Shale Gas	4.5	–	4.5	4.3	1.1	–
Other Natural Gas	2.8	0.1	2.9	2.3	0.6	–
Total Gas	**7.3**	**0.1**	**7.4**	**6.6**	**1.7**	**–**
Company Total	**34.3**	**1.1**	**35.4**	**29.8**	**11.7**	**–**

* Wells drilled during the quarter that are pending potential completion/tie-in or abandonment
** Total wells brought on-stream during the quarter regardless of when they were drilled

Bakken/Tight Oil

Our Bakken/tight oil production increased during the third quarter by approximately 900 BOE/day to average 13,511 BOE/day. The increase in production is attributable to our successful drilling activities in our U.S. Bakken properties in Montana and North Dakota. However, as a result of flooding earlier in the year in North Dakota, major state highway repair work continued into the third quarter and slowed our planned activities at Fort Berthold. The combination of these issues also impacted the pace of construction of our third-party gathering system at Fort Berthold which was originally expected in late spring, delaying tie-in activity and adding to our trucking costs in this area.

We invested $90 million in drilling, completions and tie-in activities during the quarter. We completed our 2011 drilling program in the Sleeping Giant field in Montana drilling two gross (1.5 net) operated horizontal wells. Four gross well completions in the area planned for the quarter were delayed until October, however, all are now on-stream and producing at a total rate of 2,200 BOE/day gross, 1,500 BOE/day net to Enerplus.

At Fort Berthold we drilled one long and six short Bakken horizontal wells and one long and two short Three Forks horizontal wells during the quarter. Three long and one short Bakken horizontal wells were completed during the quarter along with our first long Three Forks horizontal well. The long Three Forks well has produced over 25,000 barrels of oil in the first 30 days and had water cuts of approximately 30%, similar to those in the Bakken. Current production from this well is approximately 600 BOE/day with 1,200 psi flowing pressure. We continue to be pleased with the performance of our wells versus our estimated type curves. We also completed our first salt water disposal well late in the quarter. This well will allow us to reduce our trucking and water handling costs going forward. The completion of this disposal well, reduced drilling times due to the use of walking rigs and expected savings in rig moves, construction and tie-ins as a result of multi-well pads provide us with greater confidence in achieving our expected well costs of $6.7 million for short lateral wells and $8.7 million for long lateral wells, including tie-ins, despite upward cost pressures in this busy basin.

We currently have four rigs working at Fort Berthold and expect to maintain this rig count through the remainder of 2011 and into 2012. The build out of the first phase of the gathering system was completed by October and we have commenced gas sales from 14 of our producing wells. We anticipate that six of the 13 completions planned in the fourth quarter will also be tied into the gathering system immediately with the remainder tied in as compression facilities permit. We expect incremental production volumes of approximately 10% associated with the capture and sale of the natural gas once wells are tied into the gathering system.

Crude Oil Waterfloods

Our waterflood portfolio continues to be a core holding for Enerplus providing us with exposure to a variety of crude oil plays across western Canada that offer low decline production with significant upside potential. We invested $33 million in our waterflood portfolio during the quarter, drilling 14 net wells primarily targeting the Ratcliffe and Viking formations. Four net Ratcliffe wells were drilled and placed on-stream at Freda Lake with results that were 10% above our type curve expectations of 140 BOE/day per well. We expect to drill another four wells at Freda Lake through the end of the year. We also drilled five horizontal gross Viking wells at Gleneath with positive early test results.

Our polymer flood project at Giltedge is proceeding well. We're seeing polymer break through in a number of producing wells and we are now working to ensure the polymer is moving through the reservoir as efficiently as possible. We are encouraged by the early signs of improved oil production and reduced water cuts. Our annual production estimate at Giltedge has increased from 1,650 BOE/day to 1,900 BOE/day due to the polymer project and other optimization work. We have also increased our exit production outlook for the field by 600 BOE/day primarily due to these activities. As we see further reservoir response, we will evaluate our options of accelerating and/or expanding the next phase of enhanced oil recovery at Giltedge.

We have a busy program planned for the fourth quarter on our oil waterflood properties where we expect to drill 13 operated wells with the bulk of our activity focused on our Pembina, Virden, and Freda Lake properties. We will also continue constructing facilities at Medicine Hat to support the start-up of our second polymer flood project early in 2012.

Marcellus

We continued to see high activity levels in the Marcellus throughout the third quarter of 2011 with capital spending of $50 million on both our operated and non-operated leases. Our well results continue to exceed our expectations with net production growing by 3 MMcf/day, after adjusting for the sale of a portion of our interests late in the second quarter, to 15 MMcf/day in the third quarter. We participated in drilling 36 gross wells (4.5 net) with eight gross wells (1.1 net) coming on-stream. Although completion activity increased during the third quarter, there still continues to be a significant inventory of wells waiting to be completed and tied-in to pipelines due to the extremely wet spring and delays in pipeline gathering projects. We currently have 214 gross wells (15.5 net) waiting on completion and/or tie-in. Our current net production is 19 MMcf/day.

On our non-operated leases in the northeast region of Pennsylvania, drilling activity continued at a brisk pace with approximately 12 rigs working in the play. EXCO continues to run a three rig development program focused on multi-well pad drilling exclusively in Lycoming County. Both Chief and Chesapeake are also very active with three and six rigs running respectively in the northeast area of Pennsylvania focused primarily on lease retention strategies. The Marcellus continues to experience high levels of activity as producers drill to hold acreage and explore new step out areas and slowly move into development. There are currently 165 horizontal rigs running in the basin, concentrated in Pennsylvania and West Virginia. Well performance for the year in northeast Pennsylvania continues to outperform our expectations. Our partners are averaging 4,000 – 5,000 foot laterals, trending longer where acreage allows with an average of 8 – 15 frac stages. Chesapeake is extending the lateral length on their latest wells to approximately 6,000 feet. Current well costs in the northeast are ranging from $6.5 million to $8.0 million, slightly higher than previous quarters due to longer laterals and an extra casing string for water protection.

In our operated areas, we continue to run a one rig appraisal program and moved this rig from Clinton County, Pennsylvania to Preston County, West Virginia during the quarter. We drilled one well in southwest Preston County and are preparing to complete the well in early November. We also recently finished drilling our second well in the southeast area of Preston County and will start completion activities following rig release on our first well in southwest Preston County. Both of these wells are expected to be tied-in to pipeline by late in the first quarter of 2012. We plan to drill a third well in West Virginia before year-end and then move back to Clinton County to drill a second well during the winter. Work on our initial well in Clinton County has been completed. Our extended test showed a 24 hour peak rate of 8.3 MMcf/day (our expected 24 hour peak rate was 3.5 MMcf/day) with flowing tubing pressure of 2,600 psi.

Deep Tight Gas

We spent $20 million in delineation and development capital during the third quarter on both our operated and non-operated properties. We completed one operated well in the Bluesky formation at Ansell and initial production results of 4.2 MMcf/day are above our type curve. We also spudded a Wilrich horizontal well at Minehead, which is our first in the area and we expect to complete it in November with a late Q4/early Q1 expected tie-in. We also recently completed a vertical Stacked Mannville well at South Ansell where we are testing both the Gething and Cadomin zones. We plan to test the Wilrich zone in this well before the end of the year. This is an important delineation well for us as success here will provide added confidence for the potential development of South Ansell in 2012. We expect to drill a Montney test well at Cameron in the fourth quarter and will drill our first test in the Duvernay in 2012.

SUMMARY

While we've experienced a number of challenges in executing our 2011 capital program to date, we continue to be encouraged by our well results, the additional growth positions we have been able to build and the strength we have maintained in our financial position. We're excited about the prospects within our portfolio and the opportunity they represent for future growth in reserves, production and cash flow. We have a very active capital program planned for the fourth quarter that we expect will add significant production volumes to achieve our exit target of 81,000 – 84,000 BOE/day. While there continues to be much uncertainty and volatility in the capital markets as a result of debt issues in Europe and slow economic growth in the U.S., Enerplus is in a very strong financial position. We have preserved our balance sheet strength and are utilizing it to achieve our growth plans in the near term and believe we are on track to deliver on these plans.

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 November 9, 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 nine months ended September 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 15 of the Interim Financial Statements for more information.

All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the 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. Consistent with Canadian practice all production volumes are presented on a gross basis, being the Company's working interest share before deduction of any royalty interests paid to others.

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 September 30,		Nine months ended September 30,	
($ thousands)	2011	2010	2011	2010
Cash flow from operating activities	**$ 85,522**	$ 203,337	**$ 381,248**	$ 554,150
Decommissioning liabilities settled	**4,937**	2,300	**13,108**	10,181
Changes in non-cash operating working capital	**32,803**	(12,309)	**22,571**	2,032
Funds Flow	**$ 123,262**	$ 193,328	**$ 416,927**	$ 566,363

"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 third quarter of 2011 production averaged 73,245 BOE/day which was lower than expected due to delays in well completion and tie-in activities. We now expect annual average production of approximately 76,000 BOE/day which is at the lower end of our previous guidance range. Operating costs were higher than expected totaling $73.6 million ($10.92/BOE) due to non-recurring costs for well servicing and repairs resulting from the wet weather earlier in the year along with increased costs in our Western U.S. operations resulting from high activity levels. We are increasing our annual operating cost guidance to $9.60/BOE from $9.20/BOE based on the costs incurred to date. Our general and administrative expenses were $19.3 million in the third quarter ($2.87/BOE) and remain consistent with our expectations for the year.

Funds flow for the quarter totaled $123.3 million, down from $193.3 million in the third quarter of 2010. The majority of the reduction is due to current taxes in 2011 resulting from our Marcellus disposition along with adjustments to prior year tax estimates. We recorded a current tax expense of $32.3 million in the third quarter of 2011 compared to a current tax recovery of $33.7 million in the third quarter of 2010. Looking ahead into 2012 we are expecting a nominal amount of current taxes. The reduction in our funds flow impacted our payout ratio and adjusted payout for the quarter, which were 79% and 245% respectively.

We expect a meaningful build in our production in the fourth quarter with our efforts focused in Fort Berthold where we have nine wells planned for completion in November and four wells planned for completion in December. We are still expecting to meet our exit production guidance of 81,000 – 84,000 BOE/day, however there is some risk relative to the availability of chemical and proppant in the Williston basin which continues to be a very busy area.

RESULTS OF OPERATIONS

Production

Production in the third quarter averaged 73,245 BOE/day, down from 75,383 BOE/day in the second quarter of 2011 reflecting the Marcellus disposition of approximately 1,100 BOE/day which occurred on June 28th. In addition, our completion and tie-in activities were behind schedule resulting in fewer wells being brought on-stream and ultimately lower production than what we had anticipated. We are however, seeing performance results that are in-line with or exceeding our type well expectations once our wells are tied-in and producing.

Compared to the third quarter of 2010, production in the third quarter of 2011 decreased 12%, or 9,624 BOE/day, primarily due to our non-core asset dispositions in 2010 along with our Marcellus disposition in 2011.

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

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2011**	**2010**	**% Change**	**2011**	**2010**	**% Change**
Natural gas (Mcf/day)	**243,675**	285,292	(15)%	**250,244**	293,543	(15)%
Crude oil (bbls/day)	**29,337**	31,639	(7)%	**29,665**	31,393	(6)%
Natural gas liquids (bbls/day)	**3,295**	3,681	(10)%	**3,323**	3,842	(14)%
Total daily sales (BOE/day)	**73,245**	82,869	(12)%	**74,695**	84,159	(11)%

We have a busy capital program planned for the fourth quarter as we plan to execute a significant number of projects that were delayed in the second and third quarters. We anticipate a meaningful build in our production volumes with the majority of the volumes coming from the Fort Berthold area where we plan to complete and tie-in 13 short lateral wells. Due to high activity levels in the Fort Berthold area and the resulting competition for services, there is potential for some of this production to be delayed until early 2012. Our annual average production for the year is expected to be approximately 76,000 BOE/day (lower end of previous guidance range), while our exit guidance remains unchanged at 81,000 – 84,000 BOE/day.

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 nine months ended September 30, 2011 and 2010. It also compares the benchmark price indices for the same periods.

	Three months ended September 30,			Nine months ended September 30,		
Average Selling Price[(1)]	**2011**	**2010**	**% Change**	**2011**	**2010**	**% Change**
Natural gas (per Mcf)	**$ 3.73**	$ 3.67	2%	**$ 3.83**	$ 4.19	(9)%
Crude oil (per bbl)	**77.57**	66.97	16%	**82.01**	69.80	17%
Natural gas liquids (per bbl)	**64.98**	46.69	39%	**63.89**	50.61	26%
Per BOE	**46.44**	40.08	16%	**48.35**	42.96	13%

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

	Three months ended September 30,			Nine months ended September 30,		
Average Benchmark Pricing	**2011**	**2010**	**% Change**	**2011**	**2010**	**% Change**
AECO natural gas – monthly index (CDN$/Mcf)	**$ 3.72**	$ 3.72	0%	**$ 3.74**	$ 4.31	(13)%
AECO natural gas – daily index (CDN$/Mcf)	**3.66**	3.55	3%	**3.77**	4.13	(9)%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	**4.19**	4.41	(5)%	**4.23**	4.62	(8)%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	**4.11**	4.59	(10)%	**4.15**	4.76	(13)%
WTI crude oil (US$/bbl)	**89.76**	76.20	18%	**95.48**	77.65	23%
WTI crude oil CDN$ equivalent (CDN$/bbl)	**88.00**	79.38	11%	**93.61**	80.05	17%
US/CDN exchange rate	**1.02**	0.96	6%	**1.02**	0.97	5%

During the third quarter of 2011 the average of the AECO monthly and daily indices dropped 3% to $3.69/Mcf, compared to $3.81/Mcf in the second quarter. Downward pressure on natural gas prices continued as a result of the continued oversupply due to strong shale gas production.

We realized an average price on our natural gas sales of $3.73/Mcf during the third quarter of 2011, a 2% increase from $3.67/Mcf for the same period in 2010. In comparison, the average of the AECO daily and monthly indices increased by 2% while the NYMEX index decreased by 5%. For the nine months ended September 30, 2011 we realized an average price of $3.83/Mcf, a 9% decrease from the same period in 2010. This compares to an 11% decrease in the average of the AECO daily and monthly indices and an 8% decrease in the NYMEX index. Currently the majority of our natural gas sales are priced with reference to either the monthly or daily AECO indices. 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. Marcellus pricing captures a premium to NYMEX pricing given its close proximity to the largest demand region for natural gas in the U.S. This changing portfolio mix is improving our realized pricing relative to the AECO indices.

The West Texas Intermediate ("WTI") price for the third quarter of 2011 decreased 12% to average US$89.76/bbl from US$102.56/bbl during the second quarter of 2011. Global oil prices weakened due to lower expectations surrounding economic growth. High debt levels and the political sentiment in the U.S. have cast doubt on a U.S. economic recovery while the ongoing sovereign debt crisis has tempered growth in Europe.

Our average realized crude oil sales price was $77.57/bbl for the third quarter, a 16% increase from $66.97/bbl during the same period in 2010. In comparison, WTI increased 18% and WTI expressed in Canadian dollars increased 11% during this period. Generally, due to our crude oil sales mix, we expect the change in our realized price to fall between the change in the WTI benchmark and the Canadian dollar equivalent of WTI.

For the nine months ended September 30, 2011 our realized crude oil sales price was $82.01/bbl, a 17% increase from $69.80/bbl during the same period. In comparison, WTI increased 23% and WTI expressed in Canadian dollars increased 17% during this period. The increase in our realized price is less favorable than the increase in WTI due to wider heavy oil differentials in 2011 compared to 2010.

The Canadian dollar strengthened against the U.S. dollar during the three and nine months ended September 30, 2011 compared to the same periods 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, 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, including additional Brent-WTI spread positions. We have not added any natural gas positions due to low forward prices for natural gas. See Note 14 for a detailed list of our current price risk management positions.

The following is a summary of the financial contracts in place at October 28, 2011 expressed as a percentage of our anticipated net production volumes:

	Crude Oil (US$/bbl)		
	October 1, 2011 – December 31, 2011	**January 1, 2012 – December 31, 2012**	**January 1, 2013 – December 31, 2013**
WTI Purchased Puts (floor prices)	–	$ 103.00	–
%	–	3%	–
WTI Sold Puts (limiting downside protection)	$ 56.50	$ 65.00	$ 63.00
%	12%	7%	3%
WTI Swaps (fixed price)	$ 87.27	$ 95.32	$ 102.95
%	62%	50%	3%
WTI Sold Calls (capped price)	–	$ 133.00	–
%	–	3%	–
WTI Purchased Calls (repurchasing upside)	$ 101.17	$ 103.00	$ 102.95
%	12%	3%	3%
Brent – WTI Spread	–	$ 14.99	–
%	–	10%	–

Based on weighted average price (before premiums), estimated average annual production of 76,000 BOE/day (net of royalties of 18%) for 2011 and 83,000 to 85,000 BOE/day (net of royalties of 20%) for 2012.

Accounting for Price Risk Management

During the third quarter of 2011 we only had crude oil hedging contracts outstanding as our natural gas contracts expired on March 31, 2011. Our price risk management program generated cash losses of $4.5 million during the third quarter, compared to net cash gains of $21.0 million during the third quarter of 2010. For the nine months ended September 30, 2011 we realized cash gains of $13.3 million on natural gas contracts and cash losses of $35.5 million on crude oil contracts, compared to net cash gains of $42.3 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 during the first quarter. 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 and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At September 30, 2011 the fair value of our crude oil contracts, net of premiums, represented a gain of $89.3 million which is recorded as a current deferred financial asset 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 nine months of 2011 resulted in unrealized losses of $12.6 million for natural gas and unrealized gains of $127.6 million for crude oil. See Note 14 for details.

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

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	**Three months ended September 30, 2011**		**Three months ended September 30, 2010**	
Cash gains/(losses):				
Natural Gas	**$ –**	$ – /Mcf	$ 20.9	$ 0.80/Mcf
Crude Oil	**(4.5)**	$ (1.67)/bbl	0.1	$ (0.03)/bbl
Total cash gains/(losses)	**$ (4.5)**	$ (0.67)/BOE	$ 21.0	$ 2.76/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – natural gas	**$ –**	$ – /Mcf	$ (2.0)	$ (0.08)/Mcf
Change in fair value – crude oil	**121.6**	$ 45.05/bbl	(15.1)	$ (5.19)/bbl
Total non-cash gains/(losses)	**$ 121.6**	$ 18.05/BOE	$ (17.1)	$ (2.24)/BOE
Total gains/(losses)	**$ 117.1**	$ 17.38/BOE	$ 3.9	$ 0.52/BOE

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	**Nine months ended September 30, 2011**		**Nine months ended September 30, 2010**	
Cash gains/(losses):				
Natural Gas	**$ 13.3**	$ 0.19/Mcf	$ 48.7	$ 0.61/Mcf
Crude Oil	**(35.5)**	$ (4.38)/bbl	(6.4)	$ (0.75)/bbl
Total cash gains/(losses)	**$ (22.2)**	$ (1.09)/BOE	$ 42.3	$ 1.84/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – natural gas	**$ (12.6)**	$ (0.18)/Mcf	$ 10.1	$ 0.13/Mcf
Change in fair value – crude oil	**127.6**	$ 15.76/bbl	17.7	$ 2.07/bbl
Total non-cash gains/(losses)	**$ 115.0**	$ 5.64/BOE	$ 27.8	$ 1.21/BOE
Total gains/(losses)	**$ 92.8**	$ 4.55/BOE	$ 70.1	$ 3.05/BOE

Revenues

Crude oil and natural gas revenues for the third quarter of 2011 were $312.9 million ($317.7 million, net of $4.8 million of transportation costs), an increase of 2% or $7.4 million compared to $305.5 million ($312.7 million, net of $7.2 million of transportation costs) for the third quarter of 2010. Crude oil and natural gas revenues for the nine months ended September 30, 2011 were $985.8 million ($1,001.2 million, net of $15.4 million of transportation costs), a decrease of $1.2 million compared to $987.0 million ($1,007.5 million, net of $20.5 million of transportation costs) for the same period in 2010. The sale of approximately 10,400 BOE/day of production during 2010 has impacted our revenue in 2011, however rising crude oil and liquids prices has helped to offset the impact.

Analysis of Sales Revenue(1) ($ millions)	**Crude Oil**	**NGLs**	**Natural Gas**	**Total**
Quarter ended September 30, 2010	$ 194.9	$ 15.8	$ 94.8	$ 305.5
Price variance(1)	28.5	5.6	1.3	35.4
Volume variance	(14.2)	(1.7)	(12.1)	(28.0)
Quarter ended September 30, 2011	**$ 209.2**	**$ 19.7**	**$ 84.0**	**$ 312.9**

($ millions)	**Crude Oil**	**NGLs**	**Natural Gas**	**Total**
Year-to-date September 30, 2010	$ 598.2	$ 53.1	$ 335.7	$ 987.0
Price variance(1)	98.8	12.0	(23.9)	86.9
Volume variance	(32.9)	(7.2)	(48.0)	(88.1)
Year-to-date September 30, 2011	**$ 664.1**	**$ 57.9**	**$ 263.8**	**$ 985.8**

(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 nine months ended September 30, 2011 royalties were $56.1 million and $176.9 million respectively, compared to $55.6 million and $177.8 million for the same periods of 2010. Our average royalty rate in both 2011 and 2010 was approximately 18%, calculated as a percentage of oil and gas sales, net of transportation costs. Our average royalty rate guidance for 2011 of 20% anticipated additional production from Fort Berthold earlier in the year, which carries a higher royalty rate of approximately 30%. With the delay of this production into the fourth quarter we are expecting the average royalty rate for 2011 to remain at approximately 18%.

Operating Expenses

Operating costs for the third quarter of 2011 were $73.6 million compared to $78.4 million for the third quarter of 2010. Operating costs in 2011 have decreased on a total dollar basis largely due to our 2010 non-core asset divestments.

Throughout 2011 we have seen an increase in our operating costs, from $57.1 million ($8.40/BOE) in the first quarter to $67.5 million ($9.84/BOE) in the second quarter and $73.6 million ($10.92/BOE) in the third quarter. Some of the increase is due to non-recurring charges for well servicing and repairs and maintenance resulting from wet weather in the spring and early summer, including $2.5 million in the third quarter to clean-up a landslide at our Tommy Lakes property. In the Fort Berthold area our fluid handling charges have been increasing due to restricted access to disposal wells and higher trucking costs as a result of truck shortages and road bans. Our first quarter operating costs benefited from a $3.1 million non-cash mark to market gain on our electricity contracts which exaggerates the increases in the second and third quarters.

Looking ahead we expect our operating costs to moderate as the majority of the incremental costs related to the wet weather have been incurred and costs in Fort Berthold will flatten as pipeline infrastructure and a salt water disposal well are put in place. Based on our costs experienced to date we are increasing our 2011 operating cost guidance from $9.20/BOE to $9.60/BOE.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three and nine months ended September 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 September 30, 2011		
	Crude Oil	**Natural Gas**	**Total**
Average Daily Production	32,711 BOE/day	243,202 Mcfe/day	73,245 BOE/day
Netback[1] $ per BOE or Mcfe	**(per BOE)**	**(per Mcfe)**	**(per BOE)**
Revenue[2]	$ 71.38	$ 4.39	$ 46.44
Royalties	(15.32)	(0.45)	(8.33)
Cash operating costs	(12.06)	(1.66)	(10.90)
Netback before hedging	**$ 44.00**	**$ 2.28**	**$ 27.21**
Cash gains/(losses)	(1.49)	–	(0.66)
Netback after hedging	**$ 42.51**	**$ 2.28**	**$ 26.55**
Netback before hedging ($ millions)	**$ 132.4**	**$ 51.0**	**$ 183.4**
Netback after hedging ($ millions)	**$ 127.9**	**$ 51.0**	**$ 178.9**

	Three months ended September 30, 2010		
	Crude Oil	**Natural Gas**	**Total**
Average Daily Production	35,047 BOE/day	286,931 Mcfe/day	82,869 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 61.77	$ 4.03	$ 40.08
Royalties	(12.97)	(0.52)	(7.29)
Cash operating costs	(12.03)	(1.44)	(10.08)
Netback before hedging	$ 36.77	$ 2.07	$ 22.71
Cash gains/(losses)	0.03	0.79	2.76
Netback after hedging	$ 36.80	$ 2.86	$ 25.47
Netback before hedging ($ millions)	$ 118.5	$ 54.5	$ 173.0
Netback after hedging ($ millions)	$ 118.6	$ 75.4	$ 194.0

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

	Nine months ended September 30, 2011		
	Crude Oil	**Natural Gas**	**Total**
Average Daily Production	32,745 BOE/day	251,702 Mcfe/day	74,695 BOE/day
Netback[1] $ per BOE or Mcfe	**(per BOE)**	**(per Mcfe)**	**(per BOE)**
Revenue[2]	$ 75.77	$ 4.49	$ 48.34
Royalties	(15.61)	(0.54)	(8.67)
Cash operating costs	(11.16)	(1.47)	(9.87)
Netback before hedging	**$ 49.00**	**$ 2.48**	**$ 29.80**
Cash gains/(losses)	(3.97)	0.19	(1.09)
Netback after hedging	**$ 45.03**	**$ 2.67**	**$ 28.71**
Netback before hedging ($ millions)	**$ 437.6**	**$ 170.0**	**$ 607.6**
Netback after hedging ($ millions)	**$ 402.1**	**$ 183.3**	**$ 585.4**

	Nine months ended September 30, 2010		
	Crude Oil	**Natural Gas**	**Total**
Average Daily Production	34,999 BOE/day	294,960 Mcfe/day	84,159 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 63.81	$ 4.69	$ 42.96
Royalties	(13.92)	(0.56)	(7.74)
Cash operating costs	(12.34)	(1.40)	(10.05)
Netback before hedging	$ 37.55	$ 2.73	$ 25.17
Cash gains/(losses)	(0.67)	0.60	1.84
Netback after hedging	$ 36.88	$ 3.33	$ 27.01
Netback before hedging ($ millions)	$ 358.8	$ 219.9	$ 578.7
Netback after hedging ($ millions)	$ 352.4	$ 268.6	$ 621.0

(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 nine months of 2011. Crude oil netbacks have increased during 2011 due to higher prices partially offset by higher hedging losses. Natural gas netbacks have decreased due to lower prices and lower hedging gains as our natural gas hedges expired on March 31, 2011.

General and Administrative ("G&A") Expenses

Cash G&A expenses for the third quarter of 2011 were $16.5 million or $2.45/BOE compared to $20.1 million or $2.65/BOE for the same period during 2010. The $3.6 million decrease was primarily due to reduced estimates for our long-term incentive plans at September 30, 2011 based on our lower period-end share price.

Cash G&A expenses for the nine months ended September 30, 2011 were $60.4 million or $2.96/BOE compared to $57.9 million or $2.53/BOE for the same period during 2010. Our year-to-date cash G&A expenses were $2.5 million higher than the prior year primarily due to higher compensation costs incurred in 2011.

Non-cash G&A expenses have fluctuated between 2011 and 2010 due to the method of accounting for our predecessor rights incentive plan under IFRS resulting from our conversion to a corporation. 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 13 for further details.

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

General and Administrative Costs ($ millions)	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Cash G&A	**$ 16.5**	$ 20.1	**$ 60.4**	$ 57.9
Stock option plan (non-cash)	**2.8**	5.5	**9.6**	5.4
Total G&A	**$ 19.3**	$ 25.6	**$ 70.0**	$ 63.3
(Per BOE)	**2011**	**2010**	**2011**	**2010**
Cash G&A	**$ 2.45**	$ 2.65	**$ 2.96**	$ 2.53
Stock option plan (non-cash)	**0.42**	0.71	**0.47**	0.23
Total G&A	**$ 2.87**	$ 3.36	**$ 3.43**	$ 2.76

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 expenses.

Finance Expense

Finance expense includes cash interest costs on our senior notes and bank credit facility. Interest on our senior notes and bank credit facility for the three and nine months ended September 30, 2011 totaled $10.7 million and $35.3 million respectively, compared to $11.4 million and $30.5 million for the same periods in 2010. For the first six months of 2011 our interest expense was higher than 2010 due to higher debt levels and increased drawn and undrawn fees in 2011. At the end of the second quarter of 2011, we applied the $567.9 million of proceeds received from our Marcellus disposition against our bank debt which lowered our interest expense for the third quarter.

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 10 for further details.

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

Finance Expense ($ millions)	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Interest on senior notes and bank facility	**$ 10.7**	$ 11.4	**$ 35.3**	$ 30.5
Non-cash finance expense	**0.1**	6.2	**7.3**	13.5
Total Finance Expense	**$ 10.8**	$ 17.6	**$ 42.6**	$ 44.0

At September 30, 2011, after including our underlying derivatives, approximately 55% of our debt was based on fixed interest rates while 45% had floating interest. In comparison, at September 30, 2010 approximately 65% of our debt was based on fixed interest rates and 35% was floating.

Foreign Exchange

We recorded net foreign exchange losses of $6.2 million and $3.3 million for the three and nine months ended September 30, 2011 respectively, compared to gains of $3.6 million and $0.4 million during the same periods in 2010. The current year losses primarily result from the weaker Canadian dollar at September 30, 2011 and the impact when we translate our U.S. dollar denominated debt to Canadian dollars. Offsetting these losses were unrealized gains on our foreign exchange swaps and CCIRS. See Note 11 for further information.

Foreign Exchange ($ millions)	**Three months ended September 30,**		**Nine months ended September 30,**	
	2011	**2010**	**2011**	**2010**
Realized loss/(gain)	**$ (3.9)**	$ 3.0	**$ 16.4**	$ 17.4
Unrealized loss/(gain)	**10.1**	(6.6)	**(13.1)**	(17.8)
Total Foreign Exchange loss/(gain)	**$ 6.2**	$ (3.6)	**$ 3.3**	$ (0.4)

Capital Investment

Capital spending for the third quarter of 2011 was $201.3 million compared to $127.9 million for the same period in 2010. Our projects are delivering results in both the Bakken and Marcellus that are in-line or better than our expectations, however it is taking longer than expected to complete and bring wells on-stream. Activity during the quarter focused predominantly on our key resource plays with $90.0 million directed towards Bakken/tight oil assets, $33.0 million for crude oil waterfloods and $50.0 million on our Marcellus assets.

Property and land acquisitions for the three and nine months ended September 30, 2011 totaled $67.3 million and $209.9 million respectively, compared to $139.7 million and $489.4 million for the same periods in 2010. During the third quarter we continued to invest in undeveloped land in Canada spending an aggregate of $31.5 million with the addition of 13,000 net acres (40,000 year-to-date) in the Duvernay liquids shale prospect, 12,000 net acres (21,000 year-to-date) on oil prospects and 7,000 net acres (16,000 year-to-date) of Montney prospective lands in British Columbia. In the U.S. we spent approximately $5.6 million in the third quarter ($27.4 million year-to-date) on additional undeveloped lands in the Marcellus. Spending on our Marcellus carry obligation was US$30.3 million for the quarter (US$93.5 million year-to-date) resulting in a remaining carry obligation of US$53.6 million at September 30, 2011. We are seeing higher carry spending than previously anticipated due to increased non-operated activity on the assets covered under the carry agreement and are now expecting carry spending of $115 million for the year (previous guidance was $90 million).

Acquisitions of $139.7 million in the third quarter of 2010 included further investment in undeveloped land in the Marcellus in West Virginia and Maryland, as well as spending on our Marcellus carry obligation.

Our total capital investment for the three and nine months ended September 30, 2011 and 2010 is outlined below:

Capital Investment ($ millions)	**Three months ended September 30,**		**Nine months ended September 30,**	
	2011	**2010**	**2011**	**2010**
E&E assets	**$ 71.4**	$ 78.2	**$ 251.4**	$ 154.1
D&P assets	**129.9**	49.7	**269.5**	156.4
Capital Spending	**201.3**	127.9	**520.9**	310.5
Office Capital	**3.3**	0.8	**8.3**	2.0
Sub-total	**204.6**	128.7	**529.2**	312.5
E&E asset acquisitions	**67.3**	134.0	**206.9**	470.8
D&P asset acquisitions	**–**	5.7	**3.0**	18.6
Property and Land Acquisitions	**67.3**	139.7	**209.9**	489.4
Property Dispositions	**(7.3)**	(150.7)	**(638.1)**	(333.5)
Total Net Capital Investment	**$ 264.6**	$ 117.7	**$ 101.0**	$ 468.4

We are expecting a busy fourth quarter with increased spending on projects that were delayed earlier in the year due to weather and the lack of available services and equipment. We continue to expect capital spending of $770 million for the year.

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 September 30, 2011 DD&A totaled $108.9 million or $16.16/BOE compared to $113.5 million or $14.89/BOE during the same period in 2010. For the nine months ended September 30, 2011 DD&A totaled $312.5 million or $15.32/BOE compared to $349.8 million or $15.23/BOE during the same period in 2010. Decreases in the amount of DD&A for the three and nine months ended September 30, 2011 are primarily due to lower production. The increase in the DD&A rate for the third quarter of 2011 is attributable to additions to PP&E in the quarter and the increase in capitalized decommissioning costs.

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 Developed and Producing ("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 third quarter of 2011 we did not record any D&P or goodwill impairments compared to the same quarter of 2010 in which we recorded D&P asset impairments of $219.1 million and goodwill impairments of $29.0 million. For the nine months ended September 30, 2011 we did not record any goodwill impairments, however we recorded D&P impairments of $32.4 million in our natural gas CGUs. For the nine months ended September 30, 2010 we recorded $316.7 million of goodwill impairments and $259.3 million of D&P impairments. All of our impairments in 2011 and 2010 resulted from lower natural gas price forecasts.

Impairments ($ millions)	**Three months ended September 30,**		**Nine months ended September 30,**	
	2011	**2010**	**2011**	**2010**
Goodwill impairments	**$ –**	$ 29.0	**$ –**	$ 316.7
D&P impairments	**–**	219.1	**32.4**	259.3
Total Impairments	**$ –**	$ 248.1	**$ 32.4**	$ 576.0

Other Assets

Other assets consist of our equity investments in entities involved in the oil and gas industry. These investments are carried at their estimated fair value with changes in fair value recorded in other comprehensive income. For the three and nine months ended September 30, 2011 the change in fair value of these investments represented an unrealized loss of $0.5 million (net of tax) and an unrealized gain of $52.8 million (net of tax) respectively. The majority of the unrealized gain was attributable to the increase in the estimated fair value of our investment in Laricina Energy Ltd. For the three and nine months ended September 30, 2010 we recorded an unrealized gain on investments of $9.1 million (net of tax) and an unrealized gain of $52.4 million (net of tax) respectively. There were no realized gains or losses on these investments for the three and nine months ended September 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 $482.2 million at September 30, 2011 compared to $392.7 million at December 31, 2010. The majority of this increase relates to the decrease in the risk free rate used to calculate the present value of the future cash outflows, which fell from 3.52% at December 31, 2010 to 2.77% at September 30, 2011. See Note 9 for further information.

Taxes

Total income tax expense for the three and nine months ended September 30, 2011 was $47.9 million and $136.6 million respectively, compared to recoveries of $84.8 million and $77.3 million for the same periods in 2010.

A current tax expense of $32.3 million was recorded during the third quarter of 2011 which included a US$25 million adjustment to reduce income tax recoveries related to Alternative Minimum Tax ("AMT") estimated during 2010. We expect to recover this AMT amount in the future as a credit against income taxes otherwise payable. The remaining current tax expense related to taxable income in our U.S. subsidiary from the gain on our Marcellus disposition. Although the gain occurred during the second quarter, we accrue taxes throughout the year based on our annual forecast of taxable income and not a quarter-by-quarter basis.

In total for 2011 we are expecting a current tax expense of US$85 million, which consists of US$60 million of cash taxes we expect to pay for the year along with the US$25 million adjustment to estimated AMT. We continue to expect a nominal amount of U.S. cash taxes in 2012.

We currently do not expect to pay material cash taxes in Canada until after 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 third quarter of 2011 was $111.3 million or $0.62 per share compared to a net loss of $136.3 million or $0.77 per share for the same period in 2010. Net income for the nine months ended September 30, 2011 was $408.8 million compared to a net loss of $243.8 million for the same period in 2010. The $247.6 million increase in net income for the third quarter of 2011 was primarily due to reduced impairment losses of $248.2 million, higher gains on our commodity instruments of $113.2 million, partially offset by higher current and deferred taxes of $132.7 million. For the nine months ended September 30, 2011 the increase in net income of $652.6 million was primarily due to lower operating expenses and depletion, depreciation and amortization totaling $69.4 million, lower impairment losses of $543.6 million and an increase in the gain on dispositions of $239.5 million, which were offset by higher current and deferred taxes totaling $213.9 million.

Cash Flow from Operating Activities

Cash flow from operating activities for the three and nine months ended September 30, 2011 was $85.5 million ($0.47 per share) and $381.2 million ($2.12 per share) respectively, compared to $203.3 million ($1.15 per share) and $554.2 million ($3.16 per share) for the same periods in 2010. The decrease in cash flow from operating activities in 2011 is due to higher current taxes in 2011 along with changes in our 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 nine months ended September 30, 2011 and 2010.

	Three months ended September 30, 2011			Three months ended September 30, 2010		
(CDN$ millions, except per share amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Natural gas (Mcf/day)	**215,826**	**27,849**	**243,675**	261,406	23,886	285,292
Crude oil (bbls/day)	**18,646**	**10,691**	**29,337**	20,788	10,851	31,639
Natural gas liquids (bbls/day)	**3,065**	**230**	**3,295**	3,681	–	3,681
Total Average Daily Production (BOE/day)	**57,682**	**15,563**	**73,245**	68,037	14,832	82,869
Pricing[1]						
Natural gas (per Mcf)	**$ 3.65**	**$ 4.32**	**$ 3.73**	$ 3.53	$ 5.21	$ 3.67
Crude oil (per bbl)	**77.63**	**77.45**	**77.57**	66.53	67.81	66.97
Natural gas liquids (per bbl)	**65.77**	**54.36**	**64.98**	46.69	–	46.69
Capital Expenditures						
Capital spending and office capital	**$ 66.9**	**$ 137.7**	**$ 204.6**	$ 71.04	$ 57.7	$ 128.7
Acquisitions	**31.5**	**35.8**	**67.3**	8.4	131.3	139.7
Dispositions	**2.2**	**(9.5)**	**(7.3)**	(150.7)	–	(150.7)
Revenues						
Oil and gas sales[1]	**$ 224.5**	**$ 88.4**	**$ 312.9**	$ 226.4	$ 79.1	$ 305.5
Royalties[2]	**(32.7)**	**(23.4)**	**(56.1)**	(36.5)	(19.1)	(55.6)
Commodity derivative instruments gain/(loss)	**117.1**	**–**	**117.1**	3.9	–	3.9
Expenses						
Operating	**$ 63.6**	**$ 10.0**	**$ 73.6**	$ 73.0	$ 5.4	$ 78.4
General and administrative	**16.5**	**2.8**	**19.3**	23.7	2.0	25.7
Depletion, depreciation and amortization	**84.2**	**24.7**	**108.9**	93.8	19.7	113.5
Impairment	**–**	**–**	**–**	248.1	–	248.1
Current income taxes expense/(recovery)	**–**	**32.3**	**32.3**	–	(33.7)	(33.7)

(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)	Nine months ended September 30, 2011 Canada	U.S.	Total	Nine months ended September 30, 2010 Canada	U.S.	Total
Average Daily Production Volumes						
Natural gas (Mcf/day)	**219,446**	**30,798**	**250,244**	274,145	19,398	293,543
Crude oil (bbls/day)	**18,923**	**10,742**	**29,665**	22,650	8,743	31,393
Natural gas liquids (bbls/day)	**3,169**	**154**	**3,323**	3,842	–	3,842
Total Average Daily Production (BOE/day)	**58,666**	**16,029**	**74,695**	72,183	11,976	84,159
Pricing[1]						
Natural gas (per Mcf)	**$ 3.67**	**$ 4.93**	**$ 3.83**	$ 4.08	$ 5.67	$ 4.19
Crude oil (per bbl)	**80.56**	**84.56**	**82.01**	69.72	70.00	69.80
Natural gas liquids (per bbl)	**64.53**	**50.73**	**63.89**	50.61	–	50.61
Capital Expenditures						
Capital spending and office capital	**$ 201.3**	**$ 327.9**	**$ 529.2**	$ 171.8	$ 140.7	$ 312.5
Acquisitions	**91.0**	**118.9**	**209.9**	148.3	341.1	489.4
Dispositions	**(60.7)**	**(577.4)**	**(638.1)**	(333.5)	–	(333.5)
Revenues						
Oil and gas sales[1]	**$ 694.2**	**$ 291.6**	**$ 985.8**	$ 789.9	$ 197.1	$ 987.0
Royalties[2]	**(104.0)**	**(72.9)**	**(176.9)**	(130.9)	(46.9)	(177.8)
Commodity derivative instruments gain/(loss)	**92.8**	**–**	**92.8**	70.1	–	70.1
Expenses						
Operating	**$ 173.1**	**$ 25.1**	**$ 198.2**	$ 217.6	$ 12.6	$ 230.2
General and administrative	**61.8**	**8.2**	**70.0**	57.9	5.5	63.4
Depletion, depreciation and amortization	**246.1**	**66.4**	**312.5**	305.9	43.9	349.8
Impairment	**32.4**	**–**	**32.4**	576.0	–	576.0
Current income taxes expense/(recovery)	**–**	**76.3**	**76.3**	–	(33.3)	(33.3)

(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 the first half of 2011 lower production was generally offset by rising crude oil prices. In the third quarter of 2011 lower production and declining crude oil prices resulted in lower oil and gas sales for the quarter.

The most significant changes to net income in 2010 were goodwill and PP&E impairment expenses. Net income for the second quarter of 2011 included a significant gain on our Marcellus disposition. During the third quarter of 2011 non-cash gains on oil hedging helped net income, however oil and gas sales were lower than the previous quarter mainly due to lower production. Net income has also been impacted by mark to market adjustments on our derivative instruments and by 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				
Third Quarter	**$ 312.9**	**$ 111.3**	**$ 0.62**	**$ 0.62**
Second Quarter	**354.2**	**268.0**	**1.50**	**1.49**
First Quarter	**318.7**	**29.5**	**0.17**	**0.16**
Total	**$ 985.8**	**$ 408.8**	**$ 2.28**	**$ 2.27**
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

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

Total debt at September 30, 2011, including the current portion of $47.9 million, was $746.6 million compared to $732.4 million at December 31, 2010 and $464.5 million at June 30, 2011. Total debt at September 30, 2011 was comprised of $265.3 million of bank indebtedness and $481.3 million of senior notes. The increase of $14.2 million from December 31, 2010 is a result of funding our capital spending and working capital requirements and is largely offset by our funds flow and the proceeds from our Marcellus disposition in the second quarter of 2011. The increase of $282.1 million from June 30, 2011 is due to our capital spending and dividends being in excess of our funds flow, along with a foreign exchange impact of $31.7 million related to translating our U.S. dollar denominated notes at the period end exchange rate. We continue to expect our capital spending and dividends to exceed our funds flow for the remainder of 2011 and into 2012 and our debt-to-funds flow ratio to increase during this time as we invest in earlier stage growth assets where there is a longer lead time to production and funds flow. At September 30, 2011 we have $734.7 million of available credit under our bank credit facility to help support our growth plans.

We continued to add foreign exchange swaps during the third 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 US/CDN $0.88 when these U.S. dollar denominated notes were issued in 2009. By utilizing these forward swaps we expect to repay the U.S. debt with significantly less Canadian dollars than we originally borrowed.

Our working capital at September 30, 2011, excluding cash and current deferred financial assets and credits, increased by $30.9 million compared to December 31, 2010. This change relates primarily to lower capital spending during the third quarter of 2011 compared to the fourth quarter of 2010, resulting in a decrease of our payable balances, and is partially offset by a reduction in our receivable balances. We expect to finance our working capital deficit with cash and our bank credit facility.

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

Financial Leverage and Coverage	September 30, 2011	December 31, 2010
Long-term debt to funds flow (12 month trailing)(1)	**1.3 x**	1.0 x
Funds flow to interest expense (12 month trailing)(2)	**12.4 x**	17.4 x
Long-term debt to long-term debt plus equity(1)	**17%**	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 September 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.

Our payout ratio, which is calculated as dividends divided by funds flow, was 79% for the third quarter of 2011 compared to 50% for the third quarter of 2010. Our adjusted payout ratio, which is calculated as dividends plus capital spending and office capital divided by funds flow, was 245% for the third quarter of 2011, compared to 116% for the same period in 2010. Our payout ratios increased during 2011 due to higher capital spending levels, some of which are not generating immediate production or funds flow, as well as lower funds flow resulting from higher cash taxes in the U.S. 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 nine months ended September 30, 2011 we paid $97.4 million and $291.2 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 sheets at fair value. Upon conversion to a corporation these liabilities were effectively converted into equity and the EELP liability was recorded to share capital and the trust unit rights liability was recorded to contributed surplus.

We had 180,582,000 shares outstanding at September 30, 2011 compared to 176,359,000 shares at September 30, 2010. We had 176,946,000 shares outstanding at December 31, 2010.

During the third quarter of 2011, 595,000 shares (2010 – 404,000) were issued pursuant to the Dividend Reinvestment Plan ("DRIP") and the stock option plan, resulting in $15.4 million (2010 – $8.8 million) of additional equity. For the nine months ended September 30, 2011, $49.7 million of additional equity (2010 – $22.7 million) and 1,934,000 shares (2010 – 1,057,000) were issued pursuant to the DRIP and the stock option plan. For further details see Note 13.

The weighted average basic number of shares outstanding for the nine months ended September 30, 2011 was 179,566,000 (2010 – 175,430,000). At November 1, 2011 we had 180,789,000 shares outstanding.

Guidance

Our 2011 operating cost, royalty rate, cash taxes and Marcellus carry spending guidance were adjusted during the third 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 BOE/day	Low end of the previous range
Exit rate 2011 production	81,000 – 84,000 BOE/day	No change
Capital spending	$770 million	No change
Marcellus carry commitment spending	$115 million	Increased from $90 million
2011 production mix	55% gas, 45% crude oil and liquids	No change
Average royalty rate	18%	Decreased from 20%
Operating costs	$9.60/BOE	Increased from $9.20/BOE
G&A expenses	$3.45/BOE	No change
Average interest and financing costs	6%	No change
Cash taxes	US$85 million	Increased from US$60 million

INTERNAL CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the period beginning on July 1, 2011 and ending on September 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

The fiscal quarter ending March 31, 2011 was our 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 issued but not yet effective at September 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 average and exit oil, natural gas and natural gas liquids production volumes and the anticipated production mix; the results from our Fort Berthold drilling program and the timing of related production; future oil and natural gas prices and our commodity risk management programs; future royalty rates on our production; anticipated cash and non-cash G&A and financing expenses; operating costs; capital spending levels in 2011 and its impact on our production levels; the amount of our 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 and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; the amount and timing of future cash dividends that we may pay to our shareholders; 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 and dividend payments as needed; the availability of third party services; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: changes in commodity prices; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties, increased debt levels or debt service requirements; inaccurate estimation of our oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in 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	September 30, 2011	December 31, 2010	January 1, 2010
Assets				
Current Assets				
Cash		**$ 12,289**	$ 8,374	$ 73,558
Accounts receivable		**115,522**	125,928	142,009
Deferred financial assets	14	**91,928**	12,641	20,364
Other current		**37,489**	49,606	5,041
		257,228	196,549	240,972
Exploration and evaluation assets	4	**854,967**	1,545,378	580,184
Property, plant and equipment	5	**4,365,115**	3,440,568	4,420,339
Goodwill	6	**157,962**	151,345	476,998
Deferred financial assets	14	**13,627**	4,631	1,997
Other assets	7	**211,683**	150,710	88,324
Total Assets		**$ 5,860,582**	$ 5,489,181	$ 5,808,814
Liabilities				
Current liabilities				
Accounts payable		**$ 294,821**	$ 350,625	$ 257,519
Dividends payable		**32,505**	32,157	31,871
Current portion of long-term debt	8	**47,853**	45,845	36,631
Deferred financial credits	14	**14,192**	56,637	37,437
		389,371	485,264	363,458
Long-term debt	8	**698,736**	686,560	522,276
Deferred financial credits	14	**28,219**	46,942	54,788
Deferred tax liability		**568,424**	484,785	588,329
Decommissioning liability	9	**482,185**	392,709	385,885
		1,777,564	1,610,996	1,551,278
Exchangeable limited partnership units	13	**–**	44,387	55,812
Trust unit rights incentive plan	13	**–**	20,156	9,074
		–	64,543	64,886
Total Liabilities		**2,166,935**	2,160,803	1,979,622
Equity				
Shareholders' capital	13	**3,427,193**	5,639,380	5,576,763
Contributed surplus	13	**25,008**	3,795	3,795
Retained Earnings/(Accumulated deficit)		**117,673**	(2,314,775)	(1,751,366)
Accumulated other comprehensive income/(loss)		**123,773**	(22)	–
		3,693,647	3,328,378	3,829,192
Total Liabilities & Equity		**$ 5,860,582**	$ 5,489,181	$ 5,808,814

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Income and Comprehensive Income

(CDN$ thousands) unaudited	Note	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Revenues					
Oil and gas sales		**$ 317,761**	$ 312,679	**$ 1,001,190**	$ 1,007,509
Royalties		**(56,096)**	(55,595)	**(176,873)**	(177,770)
Commodity derivative instruments gain/(loss)	14	**117,103**	3,874	**92,793**	70,087
		378,768	260,958	**917,110**	899,826
Expenses					
Operating		**73,607**	78,409	**198,198**	230,218
General and administrative		**19,329**	25,619	**70,041**	63,364
Transportation		**4,827**	7,139	**15,389**	20,483
Depletion, depreciation, and amortization	5	**108,884**	113,536	**312,480**	349,834
Impairments	6	**–**	248,154	**32,394**	576,012
Foreign exchange	11	**6,177**	(3,625)	**3,297**	(401)
Finance expense	10	**10,748**	17,630	**42,589**	43,955
Asset disposition (gain)/loss		**(3,937)**	(4,789)	**(302,082)**	(62,629)
Other expense/(income)		**(61)**	(76)	**(657)**	90
		219,574	481,997	**371,649**	1,220,926
Income/(loss) before taxes		**159,194**	(221,039)	**545,461**	(321,100)
Current tax expense/(recovery)	12	**32,333**	(33,705)	**76,329**	(33,296)
Deferred income tax expense/(recovery)	12	**15,540**	(51,073)	**60,280**	(44,023)
Net Income/(loss)		**$ 111,321**	$ (136,261)	**$ 408,852**	$ (243,781)
Other comprehensive income					
Change in fair value of available for sale financial instruments, net of tax	7	**$ (457)**	$ 9,143	**$ 52,761**	$ 52,429
Change in cumulative translation adjustment		**117,152**	(26,793)	**71,034**	(14,117)
Other comprehensive income, net of tax		**116,695**	(17,650)	**123,795**	38,312
Total comprehensive income/(loss)		**$ 228,016**	$ (153,911)	**$ 532,647**	$ (205,469)
Net income/(loss) per share					
Basic		**$ 0.62**	$ (0.77)	**$ 2.28**	$ (1.39)
Diluted		**$ 0.62**	$ (0.77)	**$ 2.27**	$ (1.39)
Weighted average number of shares outstanding (thousands)	13				
Basic		**180,266**	176,075	**179,566**	175,430
Diluted		**180,647**	176,332	**179,947**	177,429

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Changes in Shareholders' Equity

Nine months ended September 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	**–**	23,564
Stock option plan – cash	**11,184**	3,743
Stock option plan – non cash	**8,526**	861
Dividend Reinvestment Plan	**38,491**	18,986
Balance, end of period	**$ 3,427,193**	$ 5,623,917
Contributed Surplus		
Balance, beginning of year	**$ 3,795**	$ 3,795
Reclassification of trust unit rights liability	**20,156**	–
Stock option plan – exercised	**(8,526)**	–
Stock option plan – expensed	**9,583**	–
Balance, end of period	**$ 25,008**	$ 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)	**408,852**	(243,781)
Dividends on common shares	**(291,179)**	(287,732)
Balance, end of period	**$ 117,673**	$ (2,282,879)
Accumulated other comprehensive income		
Balance, beginning of year	**$ (22)**	$ –
Change in fair value of available for sale financial instruments, net of tax	**52,761**	52,429
Cumulative translation adjustment	**71,034**	(14,117)
Balance, end of period	**$ 123,773**	$ 38,312
Total Equity	**$ 3,693,647**	$ 3,383,145

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Operating Activities				
Net income/(loss)	**$ 111,321**	$ (136,261)	**$ 408,852**	$ (243,781)
Non-cash items add/(deduct):				
Depletion, depreciation and amortization	**108,884**	113,536	**312,480**	349,834
Impairments	**–**	248,154	**32,394**	576,012
Change in fair value of derivative instruments	**(146,811)**	22,900	**(153,698)**	(41,218)
Deferred income tax expense/(recovery)	**15,540**	(51,073)	**60,280**	(44,023)
Foreign exchange (gain)/loss on U.S. dollar debt	**31,690**	(13,990)	**18,567**	(8,483)
Accretion expense	**3,450**	3,486	**10,244**	10,996
Stock based compensation	**2,805**	5,450	**9,583**	5,385
Change in fair value of exchangeable limited partnership units	**–**	5,633	**–**	6,379
Amortization of debt transaction costs	**320**	282	**889**	(78)
Cross currency interest rate swap principal settlement	**–**	–	**19,418**	17,969
Asset disposition (gain)/loss	**(3,937)**	(4,789)	**(302,082)**	(62,629)
	123,262	193,328	**416,927**	566,363
Decommissioning liabilities settled	**(4,937)**	(2,300)	**(13,108)**	(10,181)
Changes in non-cash operating working capital	**(32,803)**	12,309	**(22,571)**	(2,032)
Cash flow from operating activities	**85,522**	203,337	**381,248**	554,150
Financing Activities				
Issuance of shares	**15,409**	8,818	**49,675**	22,729
Dividends to shareholders	**(97,416)**	(96,111)	**(291,179)**	(287,732)
Increase (decrease) in bank debt	**250,540**	(1,126)	**30,250**	168,881
Bank credit facility transaction costs	**–**	–	**–**	(5,095)
Principal repayment on senior notes	**–**	–	**(34,248)**	(35,697)
Cross currency interest rate swap principal settlement	**–**	–	**(19,418)**	(17,969)
Changes in non-cash financing working capital	**101**	76	**348**	193
Cash flow from financing activities	**168,634**	(88,343)	**(264,572)**	(154,690)
Investing Activities				
Capital expenditures	**(204,542)**	(128,742)	**(529,170)**	(312,501)
Property and land acquisitions	**(67,313)**	(139,678)	**(209,946)**	(489,425)
Property dispositions	**7,320**	150,747	**638,108**	333,523
Purchase of marketable securities	**–**	–	**–**	(1,016)
Changes in non-cash investing working capital	**17,874**	4,926	**(12,541)**	(577)
Cash flow from investing activities	**(246,661)**	(112,747)	**(113,549)**	(469,996)
Effect of exchange rate changes on cash	**418**	46	**788**	(180)
Change in cash	**7,913**	2,293	**3,915**	(70,716)
Cash, beginning of period	**4,376**	549	**8,374**	73,558
Cash, end of period	**$ 12,289**	$ 2,842	**$ 12,289**	$ 2,842
Supplementary Cash Flow Information				
Cash income taxes (received)/ paid	**$ 52,958**	$ 282	**$ 53,126**	$ (7,533)
Cash interest paid	**$ 2,959**	$ 2,838	**$ 28,087**	$ 27,225

See accompanying notes to the Condensed Consolidated Financial Statements

Notes to Condensed Consolidated Financial Statements

For the three and nine months ended September 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 November 9, 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 three and nine months ended September 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 15 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 nine months ended September 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 September 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	458,375
Dispositions	(298,621)
Transfers to Property, Plant and Equipment	(864,742)
Foreign currency translation adjustment	14,577
As at September 30, 2011	**$ 854,967**

As at September 30, 2011 the E&E asset balance of $854,967,000 (December 31, 2010 – $1,545,378,000) consists of undeveloped lands and assets that management has not fully evaluated for technical feasibility and commercial viability. The transfer of approximately $864,742,000 of

E&E assets to PP&E for the nine months ended September 30, 2011 primarily 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	272,446	8,294	280,740
Transfers from Exploration and Evaluation	864,742	–	864,742
Change in decommissioning costs	92,395	–	92,395
Dispositions	(37,405)	–	(37,405)
Foreign currency translation adjustment	75,379	340	75,719
As at September 30, 2011	**$ 5,520,996**	**$ 68,176**	**$ 5,589,172**

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	307,509	4,971	312,480
Impairment	32,394	–	32,394
Foreign currency translation adjustment	6,715	55	6,770
As at September 30, 2011	**$ 1,173,949**	**$ 50,108**	**$ 1,224,057**

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 September 30, 2011	**$ 4,347,047**	**$ 18,068**	**$ 4,365,115**

As at September 30, 2011 the Marcellus carry commitment balance remaining was US$53,552,000.

6. IMPAIRMENT EXPENSE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2011	2010	2011	2010
D&P assets	**$ –**	$ 219,124	**$ 32,394**	$ 259,329
D&P natural gas CGUs	**–**	29,030	**–**	316,683
Impairment expense	**$ –**	$ 248,154	**$ 32,394**	$ 576,012

D&P impairment expenses for the three and nine months ended September 30, 2011 were nil (September 30, 2010 – $219,124,000) and $32,394,000 (September 30, 2010 – $259,329,000) respectively. Goodwill impairment expenses for the three and nine months ended

September 30, 2010 were $29,030,000 and $316,683,000 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%.

7. OTHER ASSETS

Other assets of $211,683,000 represents Enerplus' equity investments in entities involved in the oil and gas industry. For the three and nine months ended September 30, 2011 the change in fair value of these investments represented an unrealized loss of $457,000 (September 30, 2010 – unrealized gain of $9,143,000) and an unrealized gain of $52,761,000 (September 30, 2010 – $52,429,000), net of tax, respectively.

8. DEBT

($ thousands)	September 30, 2011	December 31, 2010	January 1, 2010
Current:			
Current portion of long-term debt	**$ 47,853**	$ 45,845	$ 36,631
	47,853	45,845	36,631
Long-term:			
Bank credit facility	**$ 265,282**	$ 234,713	$ –
Senior notes			
CDN$40 million (Matures June 18, 2015)	**40,000**	40,000	40,000
US$40 million (Matures June 18, 2015)	**41,556**	39,784	41,864
US$225 million (Matures June 18, 2021)	**233,753**	223,785	235,485
US$54 million (Matures October 1, 2015)(1)	**44,880**	42,967	56,516
US$175 million (Matures June 19, 2014)(1)(2)	**73,265**	105,311	148,411
	698,736	686,560	522,276
Total debt	**$ 746,589**	$ 732,405	$ 558,907

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

On October 13, 2011, Enerplus' $1.0 billion bank credit facility was extended for a three-year term maturing October 13, 2014.

9. DECOMMISSIONING LIABILITY

($ thousands)	September 30, 2011	December 31, 2010
Decommissioning liability, beginning of year	**$ 392,709**	$ 385,885
Changes in estimates	**90,931**	59,575
Property acquisition and development activity	**2,101**	6,894
Dispositions	**(692)**	(56,629)
Decommissioning liabilities settled	**(13,108)**	(17,240)
Accretion	**10,244**	14,224
Decommissioning liability, end of period	**$ 482,185**	$ 392,709

The majority of the change in estimates relates to changes in the risk free rate used to calculate the present value liability. The decommissioning liability was calculated using a risk free rate of 2.77% at September 30, 2011 (December 31, 2010 – 3.52%).

10. FINANCE EXPENSE

($ thousands)	Three months ended September 30, 2011	2010	Nine months ended September 30, 2011	2010
Realized:				
Interest on bank debt and senior notes	**$ 10,726**	$ 11,391	**$ 35,316**	$ 30,481
Unrealized:				
Cross currency interest rate swap (gain)/loss	**(3,881)**	(2,718)	**(2,786)**	(2,597)
Interest rate swap (gain)/loss	**133**	(444)	**(1,074)**	(1,226)
Premium and transaction cost amortization	**320**	282	**889**	(78)
Accretion of decommissioning liability	**3,450**	3,486	**10,244**	10,996
Change in fair value of EELP units	**–**	5,633	**–**	6,379
Finance expense	**$ 10,748**	$ 17,630	**$ 42,589**	$ 43,955

11. FOREIGN EXCHANGE

($ thousands)	Three months ended September 30, 2011	2010	Nine months ended September 30, 2011	2010
Realized:				
Foreign exchange (gain)/loss	**$ (3,872)**	$ 2,939	**$ 16,436**	$ 17,409
Unrealized:				
(Gain)/loss on translation of U.S. dollar debt	**31,690**	(13,990)	**18,567**	(8,483)
(Gain)/loss on cross currency interest rate swap	**(5,098)**	5,988	**(18,464)**	(9,574)
(Gain)/loss on foreign exchange swaps	**(16,543)**	1,438	**(13,242)**	247
Foreign exchange (gain)/loss	**$ 6,177**	$ (3,625)	**$ 3,297**	$ (401)

12. INCOME TAX EXPENSE

($ thousands)	Three months ended September 30, 2011	2010	Nine months ended September 30, 2011	2010
Current tax expense/(recovery)				
Canada	**$ –**	$ –	**$ –**	$ –
U.S.	**32,333**	(33,705)	**76,329**	(33,296)
Total current	**$ 32,333**	$ (33,705)	**$ 76,329**	$ (33,296)
Deferred tax expense/(recovery)	**15,540**	(51,073)	**60,280**	(44,023)
Total income tax expense/(recovery)	**$ 47,873**	$ (84,778)	**$ 136,609**	$ (77,319)

13. 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.

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)	Nine months ended September 30, 2011 Shares	Amount	Year ended December 31, 2010 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	**1,374**	**38,491**	1,212	28,781
Pursuant to stock option plan	**559**	**11,184**	375	6,638
Non-cash:				
Pursuant to stock option plan	**–**	**8,526**	–	3,014
Conversion of EELP units	**–**	**–**	1,010	24,184
Balance, end of period	**180,582**	**$ 3,427,193**	176,946	$ 5,639,380

(b) Dividends

For the three and nine months ended September 30, 2011, Enerplus paid dividends of $0.18 per share per month for a total of $97,416,000 (September 30, 2010 – $96,111,000) and $291,179,000 (September 30, 2010 – $287,732,000) 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 estimates of fair value during each of the respective reporting periods:

	September 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	**1.30%**	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 $4.40 (September 30, 2010 – $4.04). At September 30, 2011, 2,524,000 options were exercisable at a weighted average reduced exercise price of $36.84 with a weighted average remaining contractual term of 3.1 years, giving an aggregate intrinsic value of $4,613,000 (September 30, 2010 – $4,079,000).

For the nine months ended September 30, 2011, 559,000 options were exercised at a weighted average reduced exercise price of $20.01. The weighted average share price during the period was $29.81.

For the three and nine months ended September 30, 2011 Enerplus expensed $2,805,000 and $9,583,000 respectively of stock based compensation expense, which is included in general and administrative expenses. The unamortized fair value of $9,596,000 at September 30, 2011 will be recognized in net income over the remaining vesting period. Activity for the periods is as follows:

	Nine months ended September 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	**2,113**	**30.36**	1,749	23.60
Exercised	**(559)**	**20.01**	(375)	17.50
Forfeited and expired	**(1,225)**	**39.33**	(1,167)	36.28
End of period	**5,786**	**$ 31.14**	5,457	$ 32.11
Options exercisable at the end of period	**2,524**	**$ 36.84**	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:

($ thousands)	Nine months ended September 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	**(8,526)**	–
Stock option plan – expensed	**9,583**	–
Balance, end of period	**$ 25,008**	$ 3,795

(d) Basic and Diluted Earnings Per Share

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2011**	**2010**	**2011**	**2010**
Net income/(loss)	**$ 111,321**	$ (136,261)	**$ 408,852**	$ (243,781)
Finance expense on EELP units	**–**	–	**–**	(2,964)
Diluted income/(loss)	**$ 111,321**	$ (136,261)	**$ 408,852**	$ (246,745)
(units – thousands)				
Weighted average shares	**180,266**	176,075	**179,566**	175,430
Dilutive impact of options	**381**	257	**381**	240
Dilutive impact of EELP units	**–**	–	**–**	1,759
Diluted shares	**180,647**	176,332	**179,947**	177,429

(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. The payment is subject to a multiplier that ranges from 0.5 to 2.0 depending on the performance of Enerplus compared to its peers over the vesting period.

For the three and nine months ended September 30, 2011 the Company recorded cash compensation costs of $1,126,000 (September 30, 2010 – $4,321,000) and $10,290,000 (September 30, 2010 – $10,607,000) respectively, which were included in general and administrative expenses. At September 30, 2011 the long term incentive plans had a liability balance of $17,754,000.

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

(thousands)	Number of PSUs	Number of RSUs
Balance, beginning of year	–	**999**
Granted	**189**	**469**
Vested	**(7)**	**(426)**
Forfeited	**(9)**	**(128)**
Balance, end of period	**173**	**914**

14. 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 September 30, 2011 and December 31, 2010 due to their short-term maturities. At September 30, 2011 the combined fair values of Enerplus' senior notes was $568,849,000 and the carrying amount was $481,308,000 (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. The deferred financial asset relating to crude oil instruments is $89,301,000 at September 30, 2011, including deferred premiums of $3,258,000. At September 30, 2011 Enerplus did not have any outstanding natural gas derivative instruments.

The following tables summarize the fair value as at September 30, 2011 and change in fair value for the three and nine months ended September 30, 2011:

Three months ended September 30, 2011 ($ thousands)	**Interest Rate Swaps**	**Cross Currency Interest Rate Swap**	**Foreign Exchange Swaps**	**Electricity Swaps**	**Commodity Derivative Instruments Oil**	**Commodity Derivative Instruments Gas**	**Total**
Deferred financial assets/(liabilities), beginning of year	$ (2,433)	$ (48,824)	$ (2,916)	$ 2,789	$ (32,283)	$ –	$ (83,667)
Change in fair value gain/(loss)	(133)[(1)]	8,979[(2)]	16,543[(3)]	(162)[(4)]	121,584[(5)]	–	146,811
Deferred financial assets/(liabilities), end of period	**$ (2,566)**	**$ (39,845)**	**$ 13,627**	**$ 2,627**	**$ 89,301**	**$ –**	**$ 63,144**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (gain of $5,098) and finance expense (gain of $3,881).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments (see below).

Nine months ended September 30, 2011 ($ thousands)	**Interest Rate Swaps**	**Cross Currency Interest Rate Swap**	**Foreign Exchange Swaps**	**Electricity Swaps**	**Commodity Derivative Instruments Oil**	**Commodity Derivative Instruments Gas**	**Total**
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)	1,074[(1)]	21,250[(2)]	13,242[(3)]	3,128[(4)]	127,645[(5)]	(12,641)[(5)]	153,698
Deferred financial assets/(liabilities), end of period	**$ (2,566)**	**$ (39,845)**	**$ 13,627**	**$ 2,627**	**$ 89,301**	**$ –**	**$ 63,144**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (gain of $18,464) and finance expense (gain of $2,786).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments (see below).

As at September 30, 2011 the following table summarizes the ending balances of the derivative instruments:

($ thousands)	**Interest Rate Swaps**	**Cross Currency Interest Rate Swap**	**Foreign Exchange Swaps**	**Electricity Swaps**	**Commodity Derivative Instruments Oil**	**Commodity Derivative Instruments Gas**	**Total**
Balance Sheet classification:							
Current assets/(liabilities)	**$ (1,513)**	**$ (12,679)**	**$ –**	**$ 2,627**	**$ 89,301**	**$ –**	**$ 77,736**
Non-current assets/(liabilities)	**$ (1,053)**	**$ (27,166)**	**$ 13,627**	**$ –**	**$ –**	**$ –**	**$ (14,592)**

For the three and nine months ended September 30, 2011 the following table summarizes the income statement effects of commodity derivative instruments:

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2011**	**2010**	**2011**	**2010**
Change in fair value gain/(loss)	**$ 121,584**	$ (17,148)	**$ 115,004**	$ 27,824
Net realized cash gain/(loss)	**(4,481)**	21,022	**(22,211)**	42,263
Commodity derivative instruments gain/(loss)	**$ 117,103**	$ 3,874	**$ 92,793**	$ 70,087

(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 October 28, 2011 are summarized below.

Crude Oil:

Instrument Type	bbls/day	US$/bbl(1)
Oct 1, 2011 – Dec 31, 2011		
WTI Swap	15,500	87.27
WTI Purchased Call	1,500	105.00
WTI Purchased Call	1,000	100.00
WTI Purchased Call	500	92.00
WTI Sold Put	1,500	55.00
WTI Sold Put	1,500	58.00
WCS Differential Swap(2)	1,000	(14.75)
Jan 1, 2012 – Dec 31, 2012		
WTI Swap	14,500	95.32
WTI Purchased Put	1,000	103.00
WTI Purchased Call	1,000	103.00
WTI Sold Put	2,000	65.00
WTI Sold Call	1,000	133.00
Brent – WTI Spread	3,000	14.99
Jan 1, 2013 – Dec 31, 2013		
WTI Swap	1,000	102.95
WTI Purchased Call	1,000	102.95
WTI Sold Put	1,000	63.00

(1) Swap transactions with a common term have been aggregated and presented as the weighted average price/bbl.
(2) Represents Western Canadian Select at Hardisty (heavy oil benchmark).

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 October 28, 2011 are summarized below:

Instrument Type	MWh	CDN$/Mwh
Oct 1, 2011 – Dec 31, 2011		
AESO Power Swap(1)	16.0	54.80
Jan 1, 2012 – Dec 31, 2012		
AESO Power Swap(1)	10.0	50.45

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

(ii) Foreign Exchange Swaps

During the first nine months of 2011 Enerplus entered into foreign exchange swaps with respect to the principal repayment on the US$225,000,000 senior notes, swapping $175,000,000 of notional principal at a US$/CDN$ rate of 1.004.

15. 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;
  - September 30, 2010 and
  - December 31, 2010.
- Consolidated Income Statement for the periods ended:
  - September 30, 2010 and
  - December 31, 2010.
- Consolidated Statement of Comprehensive Income for the periods ended:
  - September 30, 2010 and
  - December 31, 2010.
- Consolidated Statement of Changes in Equity as at:
  - September 30, 2010 and
  - December 31, 2010.

Consolidated Balance Sheet

As at January 1, 2010 Unaudited (Cdn $ millions)	Previous GAAP	E&E	Impairment	Other Assets	Decommissioning Liability	EELP Units	TURIP	Foreign Exchange	Income Tax	IFRS
		IFRS Adjustments								
		(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 September 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 j)	(Note g)	(Note h)	(Note k)	(Note f)	
Assets																
Current Assets																
Cash	$ 3	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –		$ 3
Accounts receivable	109					(12)	5									102
Assets held for sale	–					581	(165)									416
Deferred financial assets	30															30
Other current	39															39
	181	–	–	–	–	569	(160)	–	–	–	–	–	–	–	–	590
Exploration & evaluation assets	–		1,192			(261)							5			936
Property, plant & equipment, net	4,958	(1)	(1,192)	131	(260)	(308)	224	60					(12)			3,600
Goodwill	605				(446)		(1)									158
Other assets	98										100					198
Deferred financial assets	1													5		6
	5,662	(1)	–	131	(706)	(569)	223	60	–	–	100	–	(7)	5	–	4,898
	$ 5,843	$ (1)	$ –	$ 131	$ (706)	$ –	$ 63	$ 60	$ –	$ –	$ 100	$ –	$ (7)	$ 5	$ –	$ 5,488
Liabilities																
Current Liabilities																
Accounts Payable	$ 259					$ (5)	3									$ 257
Distributions payable	32															32
Current portion of long term debt	–															–
Liabilities held for sale	–					39	(15)									24
Deferred income taxes	2														(2)	–
Deferred financial credits	20															20
	313	–	–	–	–	34	(12)	–	–	–	–	–	–	–	(2)	333
Long term debt	683															683
Deferred financial credits	40															40
Decommissioning liability	209					(34)	12	216								403
Deferred income taxes	530			36	(73)		17	(42)			14		(2)		71	551
Other liabilities	41															41
	1,503	–	–	36	(73)	(34)	29	174	–	–	14	–	(2)	–	71	1,718
EELP units	–								41							41
TURIP	–									13						13
	$ 1,816	$ –	$ –	$ 36	$ (73)	$ –	$ 17	$ 174	$ 41	$ 13	$ 14	$ –	$ (2)	$ –	$ 69	$ 2,105
Equity																
Shareholders' capital	5,713								(91)	1						5,623
Contributed surplus	30									(26)						4
Accumulated deficit	(1,620)	(1)		95	(633)		46	(114)	50	12	34	(82)	(5)	5	(69)	$ (2,282)
Accumulated other comprehensive income/(loss)	(96)										52	82				38
	4,027	(1)	–	95	(633)	–	46	(114)	(41)	(13)	86	–	(5)	5	(69)	3,383
	$ 5,843	$ (1)	$ –	$ 131	$ (706)	$ –	$ 63	$ 60	$ –	$ –	$ 100	$ –	$ (7)	$ 5	$ –	$ 5,488

Consolidated Balance Sheet

As at December 31, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments Pre-exploration (Note a)	E&E (Note a)	DD&A (Note b)	Impairment (Note d)	Asset Dispositions (Note c)	Decommissioning Liability (Note e)	EELP Units (Note i)	TURIP (Note i)	Other Assets (Note j)	Foreign Exchange (Note g)	G&A (Note h)	Transaction Costs (Note k)	Income Tax (Note f)	IFRS
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	28	–	–	99	–	(11)	4	–	5,292
	$ 5,835	$ (1)	$ –	$ 170	$ (836)	$ 211	$ 28	$ –	$ –	$ 99	$ –	$ (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	(42)			12		(3)	1	34	485
EELP units	–							44							44
TURIP	–								20						20
	$ 1,445	$ –	$ –	$ 27	$ (101)	$ 54	$ 141	$ 44	$ 20	$ 12	$ –	$ (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	(113)	45	5	34	(82)	(8)	3	(45)	$ (2,314)
Accumulated other comprehensive income/(loss)	(135)									53	82				–
	3,905	(1)	–	143	(735)	157	(113)	(44)	(20)	87	–	(8)	3	(45)	3,329
	$ 5,835	$ (1)	$ –	$ 170	$ (836)	$ 211	$ 28	$ –	$ –	$ 99	$ –	$ (11)	$ 4	$ (11)	$ 5,488

Consolidated Income Statement

Three months ended September 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)	
Revenues											
Oil and gas sales	$ 313	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 313
Royalties	(56)										(56)
Commodity derivative instruments	4										4
	$ 261	–	–	–	–	–	–	–	–	–	$ 261
Expenses											
Operating costs	79										79
General and administrative	21							4			25
Transportation	7										7
Finance expense	8					4	6				18
Foreign exchange (gain) loss, net	(4)										(4)
Impairment expense	–			249							249
Depreciation, depletion & amortization	167		(50)			(4)					113
Asset disposition (gain)/loss	–				(5)						(5)
	278	–	(50)	249	(5)	–	6	4	–	–	482
Net income/(loss) before income tax	(17)	–	50	(249)	5	–	(6)	(4)	–	–	(221)
Current tax expense /(recovery)	(33)										(33)
Deferred income tax expense/(recovery)	(1)	–	14	(64)	–	–	–	–	(1)	–	(52)
Net income/(loss)	$ 17	$ –	$ 36	$ (185)	$ 5	$ –	$ (6)	$ (4)	$ 1	$ –	$ (136)

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

	Previous GAAP	IFRS
Basic	$ 0.09	$ (0.77)
Diluted	$ 0.09	$ (0.77)

Consolidated Statement of Comprehensive Income

Three months ended September 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)	$ 17	$ –	$ 36	$ (185)	$ 5	$ –	$ (6)	$ (4)	$ 1	$ –	$ (136)
Other comprehensive income, net of tax											
Change in cumulative translation adjustment	(27)										(27)
Unrealized gain on marketable securities						9					9
Comprehensive income/(loss)	$ (10)	$ –	$ 36	$ (185)	$ 5	$ 9	$ (6)	$ (4)	$ 1	$ –	$ (154)

Consolidated Income Statement

Nine months ended September 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)	
Revenues											
Oil and gas sales	$ 1,008	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 1,008
Royalties	(178)										(178)
Commodity derivative instruments	70										70
	$ 900	–	–	–	–	–	–	–	–	–	$ 900
Expenses											
Operating costs	230										230
General and administrative	55							1	7		63
Transportation	20										20
Finance expense	31					11	7			(5)	44
Foreign exchange (gain) loss, net	–										–
Impairment expense	–			576							576
Depreciation, depletion & amortization	491		(131)			(10)					350
Asset disposition (gain)/loss	–	1			(63)						(62)
	827	1	(131)	576	(63)	1	7	1	7	(5)	1,221
Net income/(loss) before income tax	73	(1)	131	(576)	63	(1)	(7)	(1)	(7)	5	(321)
Current tax expense /(recovery)	(33)										(33)
Deferred income tax expense/(recovery)	(22)	–	36	(73)	17	–	–	–	(2)	–	(44)
Net income/(loss)	$ 128	$ (1)	$ 95	$ (503)	$ 46	$ (1)	$ (7)	$ (1)	$ (5)	$ 5	$ (244)

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

	Previous GAAP	IFRS
Basic	$ 0.72	$ (1.39)
Diluted	$ 0.72	$ (1.39)

Consolidated Statement of Other Comprehensive Income

Nine months ended September 30, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments Pre-exploration	DD&A	Impairment	Asset Dispositions	Decommissioning Liability	Other Assets	EELP Units	TURIP	G&A	Transaction Costs	IFRS
		(Note a)	(Note b)	(Note d)	(Note c)	(Note e)	(Note j)	(Note i)	(Note i)	(Note h)	(Note k)	
Net income/(loss)	$ 128	$ (1)	$ 95	$ (503)	$ 46	$ (1)	$ –	$ (7)	$ (1)	$ (5)	$ 5	$ (244)
Other comprehensive income, net of tax												
Change in cumulative translation adjustment	(14)											(14)
Unrealized gain on marketable securities							52					52
Comprehensive income/(loss)	$ 114	$ (1)	$ 95	$ (503)	$ 46	$ (1)	$ 52	$ (7)	$ (1)	$ (5)	$ 5	$ (206)

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)	
Revenues													
Oil and Gas Sales	$ 1,327	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 1,327
Royalties	(223)												(223)
Commodity derivative instruments	24												24
	$ 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
Asset Disposition (gain)/loss	(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

Nine months ended September 30, 2010 Unaudited (CDN $ millions)	Previous GAAP	Pre-exploration	DD&A	Impairment	Asset Dispositions	Decommissioning Liability	EELP Units	TURIP	Other Assets	Foreign Exchange	G&A	Transaction Costs	Income Tax	IFRS
		IFRS Adjustments												
		(Note a)	(Note b)	(Note d)		(Note e)	(Note i)	(Note i)	(Note j)	(Note g)	(Note h)	(Note k)	(Note f)	
Common Shares														
Balance, beginning of year	$ 5,689	$ –	$ –	$ –	$ –	$ –	$ (113)	$ –	$ –	$ –	$ –	$ –	$ –	$ 5,576
Issued for cash:														
DRIP	19													19
Stock option plan	4													4
Non cash:														
TURIP	1						22	1						24
Balance, end of period	$ 5,713	$ –	$ –	$ –	$ –	$ –	$ (91)	$ 1	$ –	$ –	$ –	$ –	$ –	$ 5,623
Contributed Surplus														
Balance, beginning of year	$ 26	$ –	$ –	$ –	$ –	$ –	$ –	$ (22)	$ –	$ –	$ –	$ –	$ –	$ 4
Stock option plan – expensed	4							(4)						–
Balance, end of period	$ 30	$ –	$ –	$ –	$ –	$ –	$ –	$ (26)	$ –	$ –	$ –	$ –	$ –	$ 4
Accumulated Deficit														
Accumulated income, beginning of year	$ 3,265	$ –	$ –	$ (130)	$ –	$ (113)	$ 57	$ 13	$ 34	$ (82)	$ –	$ –	$ (69)	$ 2,975
Net income/(loss)	128	(1)	95	(503)	46	(1)	(7)	(1)	–	–	(5)	5	–	(244)
	3,393	(1)	95	(633)	46	(114)	50	12	34	(82)	(5)	5	(69)	2,731
Accumulated dividends, beginning of year	(4,725)													(4,725)
Dividends	(288)													(288)
	(5,013)													(5,013)
Balance, end of period	$ (1,620)	$ (1)	$ 95	$ (633)	$ 46	$ (114)	$ 50	$ 12	$ 34	$ (82)	$ (5)	$ 5	$ (69)	$ (2,282)
Accumulated Other Comprehensive Income														
Balance, beginning of year	$ (82)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 82	$ –	$ –	$ –	$ –
Change in cumulative translation adjustment	(14)													(14)
Unrealized gain on marketable securities	–								52					52
Balance, end of period	$ (96)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 52	$ 82	$ –	$ –	$ –	$ 38
Total Equity	$ 4,027	$ (1)	$ 95	$ (633)	$ 46	$ (114)	$ (41)	$ (13)	$ 86	$ –	$ (5)	$ 5	$ (69)	$ 3,383

Consolidated Statement of Changes in Equity

Twelve months ended December 31, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments Pre-exploration	DD&A	Impairment	Asset Dispositions	Decommissioning Liability	EELP Units	TURIP	Other Assets	Foreign Exchange	G&A	Income Tax	Transaction Costs	IFRS
		(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 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 $1.0 million for the periods ended September 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 was 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 September 30, 2010 and December 31, 2010 Enerplus' E&E assets were $936 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 of $4,420 million on the date of transition to IFRS was allocated to CGUs based on the attributed value of proved plus probable reserves at December 31, 2009. As at September 30, 2010 and December 31, 2010 PP&E was $3,600 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 $50 million and $131 million for the three and nine months ended September 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 the 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 nine months ended September 30, 2010 Enerplus recognized gains of $5 million and $63 million respectively. 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 year ended 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 impairment 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 nine months ended September 30, 2010 D&P impairments of approximately $219 million and $259 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.

Enerplus recognized a goodwill impairment of $130 million on the January 1, 2010 date of transition. For the three and nine months ended September 30, 2010, Enerplus recognized goodwill impairments of $29 million and $317 million respectively. 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.

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 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 CTA balance to be set to zero instead of retroactively restating the CTA. As at September 30, 2010 and December 31, 2010 CTA recognized in other comprehensive income under IFRS was approximately $14 million and $53 million respectively.

h) General and Administrative

There was no adjustment to capitalized G&A for the three months ended September 30, 2011. For the nine months ended September 30, 2010 and year ended December 31, 2010 Enerplus reduced its capitalized G&A by approximately $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 September 30, 2010 and December 31, 2010 the fair value of the EELP liability was $41 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 September 30, 2010 and December 31, 2010 the fair value of the TURIP liability was $13 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 three and nine months ended September 30, 2010 and the year ended December 31, 2010 the Enerplus recorded an increase in the fair value of investments of $11 million ($9 million net of tax), $61 million ($52 million net of tax) and $60 million ($53 million net of tax). 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 nine months ended September 30, 2010 amortization of these transactions costs was $0.5 million. 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 September 30, 2010	Nine months ended September 30, 2010	Twelve months ended December 31, 2010
Weighted average shares outstanding			
Basic	176	175	176
Diluted	176	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 September 30, 2010 Enerplus reported assets held for sale of $416 million, including $7 million of accounts receivable. Enerplus also recorded liabilities held for sale of $24 million, of which $2 million related to accounts payable and $22 million related to decommissioning liabilities. There were no assets or liabilities held for sale at December 31, 2010.

BOARD OF DIRECTORS

Douglas R. Martin(1)(2)
President
Charles Avenue Capital Corp.
Calgary, Alberta

David H. Barr(11)
President & Chief Executive Officer
Logan International Inc.
Houston, Texas

Edwin V. Dodge(9)(12)
Corporate Director
Vancouver, British Columbia

Robert B. Hodgins(3)(6)
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

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

W. C. (Mike) Seth(3)(8)
President
Seth Consultants Ltd.
Calgary, Alberta

Donald T. West(7)(11)
Corporate Director
Calgary, Alberta

Harry B. Wheeler(5)(9)
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

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

Brien A. Perry
Vice President, Human Resources

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

Telephone: 720.279.5500
Fax: 720.279.5550

ABBREVIATIONS

ABBREVIATIONS

AECO a reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices

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

BOE barrels of oil equivalent

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

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 purposes

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

PDP Reserves proved developed producing reserves

P+P Reserves proved plus probable reserves

RLI reserve life index

WCS Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes

WI percentage working interest ownership

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