THE TURNING POINT

U.S.
TOTAL RETURN:
43%

CDN TOTAL RETURN:
36%

$1 BILLION
IN ACQUISITIONS

$900 MILLION
IN DISPOSITIONS

OIL/GAS SPLIT:
42/58

3.9 TCF AND 60 MMBOE
OF CONTINGENT RESOURCES

ENERPLUS CORPORATION
2010 FINANCIAL SUMMARY

Enerplus has now reached the turning point.

The right assets are in place.

Our balance sheet is strong.

And we're positioned to deliver both growth and income to our investors.

Enerplus is a high-yielding North American energy producer with a diversified asset base of high quality, low decline oil and gas assets complimented by growth assets in resource plays with superior economics. We are focused on creating value for our investors through the successful development of our properties and the disciplined management of our balance sheet. Through these activities, we strive to provide investors with a competitive return comprised of both growth and income.

2010 SUMMARY

Selected Financial and Operating Highlights

SELECTED FINANCIAL RESULTS (in Canadian dollars)	Three months ended December 31, 2010	2009	Twelve months ended December 31, 2010	2009
Financial (000's)				
Cash Flow from Operating Activities	**$ 146,787**	$ 188,579	**$ 703,148**	$ 775,786
Cash Distributions to Unitholders(1)	**96,396**	95,550	**384,128**	368,201
Excess of Cash Flow Over Cash Distributions	**50,391**	93,029	**319,020**	407,585
Net Income / (Loss)	**(995)**	2,718	**127,112**	89,117
Debt Outstanding – net of cash	**724,031**	485,349	**724,031**	485,349
Development Capital Spending	**229,029**	118,889	**542,679**	299,111
Acquisitions	**524,338**	49,100	**1,018,069**	271,977
Divestments	**537,935**	102,070	**871,458**	104,325
Actual Cash Distributions to Unitholders per Trust Unit	**$ 0.54**	$ 0.54	**$ 2.16**	$ 2.23
Financial per Weighted Average Trust Unit(2)				
Cash Flow from Operating Activities	**$ 0.82**	$ 1.07	**$ 3.96**	$ 4.58
Cash Distributions(1)	**0.54**	0.54	**2.16**	2.17
Excess of Cash Flow Over Cash Distributions	**0.28**	0.53	**1.80**	2.41
Net Income	**(0.01)**	0.02	**0.72**	0.53
Payout Ratio(3)	**66%**	51%	**55%**	47%
Adjusted Payout Ratio(3)	**223%**	114%	**132%**	87%
Selected Financial Results per BOE(4)				
Oil & Gas Sales(5)	**$ 42.49**	$ 41.75	**$ 42.85**	$ 36.89
Royalties	**(6.21)**	(6.56)	**(7.37)**	(6.21)
Commodity Derivative Instruments	**1.02**	3.34	**1.64**	4.66
Operating Costs	**(8.29)**	(9.27)	**(9.61)**	(9.71)
General and Administrative Expenses	**(2.97)**	(3.30)	**(2.40)**	(2.44)
Interest, Foreign Exchange and Other Expenses	**(2.95)**	(0.72)	**(1.85)**	(0.34)
Taxes	**(0.40)**	0.66	**1.00**	(0.01)
Asset Retirement Obligations Settled	**(0.96)**	(0.63)	**(0.57)**	(0.41)
Cash Flow from Operating Activities before changes in non-cash working capital	**$ 21.73**	$ 25.26	**$ 23.69**	$ 22.43
Weighted Average Number of Trust Units Outstanding(2)	**178,368**	176,872	**177,737**	169,280
Debt to Trailing 12 Month Cash Flow Ratio	**1.0x**	0.6x	**1.0x**	0.6x

SELECTED OPERATING RESULTS	Three months ended December 31, 2010	Three months ended December 31, 2009	Twelve months ended December 31, 2010	Twelve months ended December 31, 2009
Average Daily Production				
Natural Gas (Mcf/day)	**274,314**	305,691	**288,692**	326,570
Crude Oil (bbls/day)	**30,368**	31,590	**31,135**	32,984
NGLs (bbls/day)	**4,027**	4,238	**3,889**	4,157
Total (BOE/day)	**80,114**	86,777	**83,139**	91,569
% Crude Oil & Natural Gas Liquids	**43%**	41%	**42%**	41%
Average Selling Price[5]				
Natural Gas (per Mcf)	**$ 3.63**	$ 4.06	**$ 4.05**	$ 3.91
Crude Oil (per bbl)	**72.18**	67.90	**70.38**	58.54
NGLs (per bbl)	**53.66**	56.96	**51.41**	41.54
US$/CDN$ exchange rate	**0.99**	0.95	**0.97**	0.88
Net Wells drilled	**40**	156	**225**	313

(1) Calculated based on distributions paid or payable.
(2) Weighted average trust units outstanding for the period, includes the equivalent exchangeable limited partnership units.
(3) Payout ratio is calculated as cash distributions to unitholders divided by cash flow from operating activities. Adjusted payout ratio is calculated as the sum of cash distributions to unitholders plus development capital and office expenditures divided by cash flow from operating activities. See "Non-GAAP Measures" below.
(4) Non-cash amounts have been excluded.
(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

Trust Unit Trading Summary **For the twelve months ended December 31, 2010**	**CDN* – ERF.un** (CDN$)	**U.S.** – ERF** (US$)
High	$ 31.85	$ 31.83
Low	$ 18.22	$ 13.76
Close	$ 30.67	$ 30.84

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

2010 Cash Distributions Per Trust Unit	**CDN$**	**US$**
First Quarter Total	**$ 0.54**	**$ 0.52**
Second Quarter Total	**$ 0.54**	**$ 0.53**
Third Quarter Total	**$ 0.54**	**$ 0.52**
Fourth Quarter Total	**$ 0.54**	**$ 0.52**
Total	**$ 2.16**	**$ 2.09**

2010 HIGHLIGHTS

STRATEGIC EXECUTION

- Enerplus acquired over $1 billion of prospective land in 2010 representing almost 300,000 net acres in key resource plays in North America that offer superior economic returns. As a result of these acquisitions, Enerplus now holds the following significant land positions in key resource plays:
  - Marcellus – ~130,000 net non-operated acres and ~70,000 net operated acres in Pennsylvania, Maryland and West Virginia
  - Bakken – ~75,000 net acres at Fort Berthold in North Dakota and ~155,000 net acres in southeast Saskatchewan
  - Deep Basin – ~80,000 net acres in Alberta and British Columbia that is prospective for the Montney and Mannville
- Throughout 2010 we actively pursued a strategic portfolio rationalization, selling approximately 10,400 BOE/day of non-core conventional oil and gas production in order to improve our operational focus and profitability. In addition, we also sold our Kirby oil sands lease. Total proceeds from these divestment activities amounted to $871.5 million.
- Our acquisition activities were funded primarily through disposition proceeds, thereby keeping our balance sheet strong and providing us with the financial flexibility required to support our capital spending plans over the next two years.
- The "best estimate" of contingent resources associated with our Marcellus interests increased 63% from 2.4 trillion cubic feet to 3.9 trillion cubic feet of natural gas at December 31, 2010. The increase in contingent resources is attributable to our acquisition of additional operated interests in West Virginia and Maryland (0.9 trillion cubic feet) and an improvement in performance of wells drilled on our non-operated leases (0.6 trillion cubic feet).
- The "best estimate" of contingent resources associated with our North Dakota Bakken crude oil leases was 60 MMBOE at December 31, 2010, 17% higher than our previous estimate, with 90 future drilling locations identified. This assessment reflects only the Bakken resource at this time as we do not have enough wells completed in the Three Forks zone to make an appropriate estimate.
- Enerplus now has over 700 million BOE of contingent resources associated with our North Dakota and Marcellus properties which provides us with significant growth potential in the coming years.
- Enerplus investors realized positive returns in 2010 with Canadian investors realizing a 35.6% total return and U.S. investors realizing a 43.4% total return. The return to our U.S. investors also reflected the appreciation of the Canadian dollar throughout the year.

OPERATIONS

- Enerplus produced an average of 83,139 BOE/day in 2010, in line with our guidance of 83,000 – 84,000 BOE/day. Daily production volumes were 8,430 BOE/day lower than the average daily volumes in 2009 due to reduced capital spending in 2009 and the sale of 10,400 BOE/day of non-core conventional oil and gas production in 2010.
- Production volumes for the month of December were 77,200 BOE/day, approximately 4% lower than our guidance of 80,000 – 82,000 BOE/day. Exit volume shortfalls were primarily associated with our Bakken production in North Dakota where extreme weather conditions in December impacted our ability to truck production to the sales terminals. Additionally, two long lateral Bakken wells which were originally slated for completion in early December were delayed. Both of these wells are now on stream with initial production rates of 1,500 bbls/day per well.
- Operating costs averaged $9.54/BOE during 2010, 6% better than our guidance of $10.20/BOE primarily as a result of the sale of high-cost non-core production and lower repairs, maintenance and electricity costs.
- In 2010, we invested $543 million through our capital program, an increase of over 80% from our spending levels in 2009. This was higher than our forecast capital spending of $515 million due in part to an increase in drilling and completion costs associated with our Marcellus program. Approximately $424 million was invested in drilling, completions and recompletions, $85 million in facilities and maintenance, and $34 million in seismic and lease rentals.
- Almost 60% of our development spending related to oil projects where we concentrated our efforts on our Bakken and waterflood assets. Over half of our natural gas spending occurred in the Marcellus where we were focused on delineation and lease retention activities, and drilling in the more prolific northeast area of Pennsylvania. Spending on our Canadian natural gas assets declined throughout the year due to low economic returns in this price environment. Because of long lead times for well completion and tie-ins in the Bakken and more particularly in the Marcellus, much of the capital spending in 2010 will not generate production and cash flow until 2011.
- A total of 225.2 net wells were drilled in 2010. Excluding 103.7 net shallow gas wells, the majority of which were drilled to take advantage of the Alberta Drilling Royalty Credit program, Enerplus drilled 121.5 net wells, 77% of which were crude oil wells. Over 80% of these wells were horizontal.

FINANCIAL

- Cash flow from operations totaled $703.1 million, down 9% from 2009 due to lower production volumes.
- We distributed $384.1 million to Unitholders through monthly distributions in 2010, representing 55% of cash flow from operating activities. When distributions and development capital spending are combined, our adjusted payout ratio for 2010 was 132%.
- We realized cash hedging gains of $49.7 million in 2010. Our natural gas contracts generated gains of $67.3 million while our crude oil contracts experienced losses of $17.6 million.
- General and administrative costs were $2.60/BOE, slightly higher than our guidance of $2.55/BOE and similar to 2009 levels.
- Our trailing 12 month debt-to-cash flow ratio was 1.0x at December 31, 2010.

RESERVES

- Total proved plus probable ("P+P") company interest reserves at December 31, 2010 were 306.2 MMBOE, down approximately 11% from year-end 2009, with approximately 60% of this decline attributable to the sale of non-core properties net of acquisitions. Proved reserves totaled 219.4 MMBOE, representing approximately 72% of total proved plus probable reserves. 53% of P+P reserves are weighted to crude oil and natural gas liquids. Our P+P reserve life index was 10.7 years.
- 34.0 MMBOE of P+P reserves were sold during 2010 of which 23.4 MMBOE were attributable to oil properties and 63.9 Bcfe were related to natural gas properties.
- 11.8 MMBOE of P+P reserves were acquired in 2010, primarily in our Fort Berthold, North Dakota Bakken oil property. The majority of our acquisitions in 2010 were of undeveloped land with nominal proved or probable reserves.
- Our development capital spending replaced 114% of 2010 production before revisions. 34.7 MMBOE of P+P reserves were added from our delineation and development activities comprised of 16.8 MMBOE from our oil properties and 107.3 Bcfe from our natural gas properties.
- The majority of the additions were attributable to our North Dakota Bakken and Marcellus resource plays at 11.0 MMBOE and 87.6 Bcfe respectively. Our Finding & Development costs ("F&D") were $10.74/BOE at Fort Berthold and $1.64/Mcfe in the Marcellus. Booked drilling locations for these areas in our reserve report represent less than one year's drilling activity based upon current plans. We also added 5.7 MMBOE in Canada across various oil properties, including our waterfloods, and 9.0 Bcfe from our deep tight gas plays.
- A decrease in the outlook for natural gas prices and underperformance in a few properties resulted in negative revisions to our natural gas properties of 108.5 Bcfe of P+P reserves and 2.6 MMBOE of P+P reserves associated with our oil properties for a total of 20.7 MMBOE of P+P reserves. The majority of the negative revisions were associated with our shallow gas assets. Roughly 40% or 45 Bcfe of our natural gas revisions related to the decline in natural gas price forecasts, while 63.5 Bcfe related to performance mainly in our Shackleton shallow gas property where well interference has changed our view on long-term performance and economics. The net present value of the performance revisions at Shackleton discounted at 10% was approximately $100 million or 2% of our 2010 year-end proved plus probable reserve value discounted at 10%. Approximately 567 natural gas locations were removed from our reserve report along with $95.6 million of associated future development capital. Of the total 20.7 MMBOE in revisions, 6.9 MMBOE or roughly one third were in the proved category. After these revisions, approximately 150 shallow gas drilling locations associated with our Shackleton property remain in our reserve report.
- The net present value of our P+P reserves (future prices discounted at 10%) was approximately $4.8 billion at December 31, 2010, down from $5.6 billion at December 31, 2009 primarily due to the sale of booked reserves and lower forecast natural gas prices.
- Our F&D cost per BOE of P+P reserves including future development costs, before reserve revisions, was $17.46 with a recycle ratio of 1.6x. This was primarily a result of the reserve additions from our new growth properties in the Bakken and the Marcellus.
- After accounting for the negative revisions attributable primarily to our shallow natural gas assets, our F&D cost was $36.71/BOE with a recycle ratio of 0.75x.
- As we acquired predominantly undeveloped land in early stage growth properties in 2010 with significant potential but few reserves, and sold non-core properties with proved plus probable reserves, the calculation of our Finding, Development & Acquisition costs resulted in a negative amount for the year.

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

The following discussion and analysis of financial results is dated February 24, 2011 and is to be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2010 and 2009. All amounts are stated in Canadian dollars unless otherwise specified. All references to GAAP refer to Canadian generally accepted accounting principles. All note references relate to the notes included with the consolidated financial statements. In accordance with Canadian practice revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise stated. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading.

These financial statements and notes present the results of Enerplus Corporation (formerly Enerplus Resources Fund). On January 1, 2011, Enerplus Resources Fund (the "Fund") converted from an income trust into a corporate entity with Enerplus Corporation being the successor issuer to the Fund. However, because the Fund, and not Enerplus Corporation, was the public reporting issuer in existence on December 31, 2010, information in this MD&A and accompanying financial statements makes reference to the Fund and its outstanding trust units rather than Enerplus Corporation and its common shares that are currently in existence.

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 on forward-looking information and statements.

NON-GAAP MEASURES

Throughout the MD&A we use the term "payout ratio" and "adjusted payout ratio" to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing cash distributions to unitholders ("cash distributions") by cash flow from operating activities ("cash flow"), both of which appear on our consolidated statements of cash flows prepared in accordance with GAAP. "Adjusted payout ratio" is calculated as cash distributions plus development capital and office expenditures divided by cash flow. The terms "payout ratio" and "adjusted payout ratio" do not have a standardized meaning or definition as prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other entities. Refer to the Liquidity and Capital Resources section of the MD&A for further information.

OVERVIEW

2010 was a transition year for Enerplus as we focused our asset base by investing over $1.0 billion in early stage growth plays and also disposed of non-core conventional assets, including our Kirby oil sands lease, for approximately $900 million in total proceeds. Our disposition activity funded the majority of our acquisitions allowing us to maintain a strong balance sheet throughout the year.

Our annual average production was in-line with guidance at 83,139 BOE/day. Our capital spending totaled $542.7 million for the year, $27.7 million above guidance due to additional costs in the Marcellus and lower Alberta Drilling Royalty Credits ("DRCs") than we had anticipated. We exited the year with production of 77,200 BOE/day, slightly below guidance primarily due to delays with two significant wells at Fort Berthold which are now on stream and had average initial production rates of 1,500 bbls/day per well. Operating costs were better than expected at $9.54/BOE while our general and administration ("G&A") expenses were in line with expectations at $2.60/BOE.

We successfully completed our corporate conversion from Enerplus Resources Fund to Enerplus Corporation effective January 1, 2011. During 2010 we maintained monthly distributions of $0.18 per trust unit. Going forward we intend to distribute a significant portion of our cash flow to investors through a monthly dividend and we expect to complement this dividend with annual growth in production and reserves per share.

RESULTS OF OPERATIONS

Production

Production during 2010 averaged 83,139 BOE/day, in-line with our guidance of 83,000 to 84,000 BOE/day and 9% lower than 91,569 BOE/day in 2009. The decrease compared to 2009 was consistent with our expectations given the reduced capital program in 2009 and the sale of approximately 10,400 BOE/day of non-core conventional oil and gas production during the year. Also, the majority of our acquisitions consisted of undeveloped land with minimal existing production.

Average production in 2010 was weighted 58% to natural gas and 42% to crude oil and liquids on a BOE basis. Average production volumes for the years ended December 31, 2010 and 2009 are outlined below:

Daily Production Volumes	2010	2009	% Change
Natural gas (Mcf/day)	**288,692**	326,570	(12)%
Crude oil (bbls/day)	**31,135**	32,984	(6)%
Natural gas liquids (bbls/day)	**3,889**	4,157	(6)%
Total daily sales (BOE/day)	**83,139**	91,569	(9)%

Our average daily production for the month of December was approximately 77,200 BOE/day, below our anticipated exit rate of 80,000 to 82,000 BOE/day. The decrease was primarily due to delays in drilling and completing two Fort Berthold wells, as well as weather conditions in North Dakota which delayed our ability to truck production to sales points.

We expect 2011 production volumes to average 78,000 to 80,000 BOE/day, with an increased weighting of crude oil and liquids to approximately 47% of overall production. We expect our production volumes to increase throughout the year exiting 2011 at approximately 80,000 to 84,000 BOE/day. This guidance does not contemplate any acquisitions or dispositions.

Pricing

As most of our crude oil and natural gas production is priced in reference to U.S. dollar denominated benchmarks, a stronger Canadian dollar decreases the prices that we would have otherwise realized. The prices received for our natural gas and crude oil production directly impact our earnings, cash flow and financial condition. The following table compares our average selling prices for 2010 with those of 2009. It also compares the benchmark price indices for the same periods.

Average Selling Price[1]		2010		2009	% Change
Natural gas (per Mcf)	**$**	**4.05**	$	3.91	4%
Crude oil (per bbl)	**$**	**70.38**	$	58.54	20%
Natural gas liquids (per bbl)	**$**	**51.41**	$	41.54	24%
Per BOE	**$**	**42.85**	$	36.89	16%

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

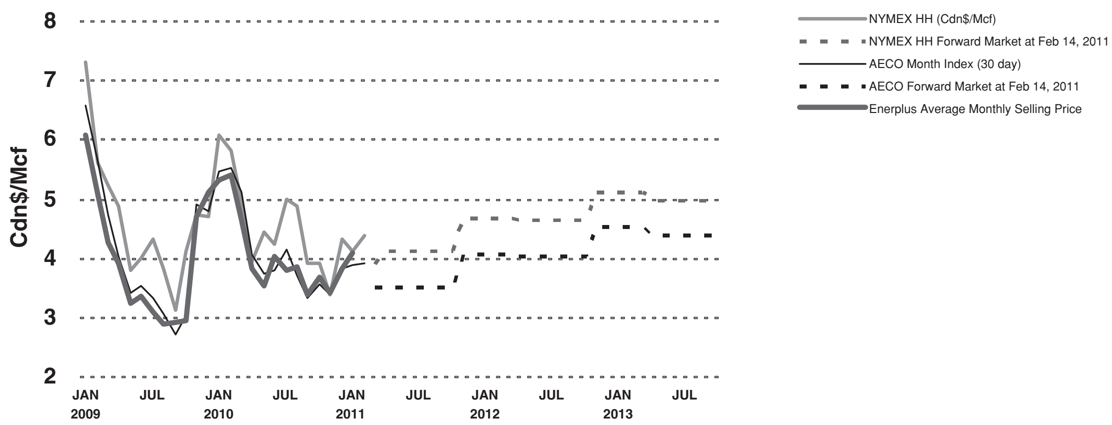
Average Benchmark Pricing		2010		2009	% Change
AECO natural gas – monthly index (CDN$/Mcf)	**$**	**4.13**	$	4.14	0%
AECO natural gas – daily index (CDN$/Mcf)	**$**	**4.00**	$	3.95	1%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	**$**	**4.42**	$	4.03	10%
NYMEX natural gas – monthly NX3 index: CDN$ equivalent (CDN$/Mcf)	**$**	**4.56**	$	4.58	0%
WTI crude oil (US$/bbl)	**$**	**79.53**	$	61.80	29%
WTI crude oil: CDN$ equivalent (CDN$/bbl)	**$**	**81.99**	$	70.23	17%
US$/CDN$ exchange rate		**0.97**		0.88	10%

Natural Gas

Natural gas prices remained depressed through 2010 as the overall supply of gas continued to increase throughout the year outpacing any increase in demand. Gas inventory levels were at record highs when we started the winter season. Even with the cold winter weather experienced in December, the daily AECO price averaged only $3.90/mcf.

During 2010 we sold approximately 84% of our natural gas on the AECO index split evenly between the daily and monthly indices and the remaining 16% against monthly U.S. based indices. During 2010 we sold our natural gas for an average price of $4.05/Mcf (net of transportation costs), an increase of 4% from $3.91/Mcf realized in 2009. This increase is generally in-line with the changes experienced on the AECO and NYMEX indices.

Monthly Natural Gas Prices

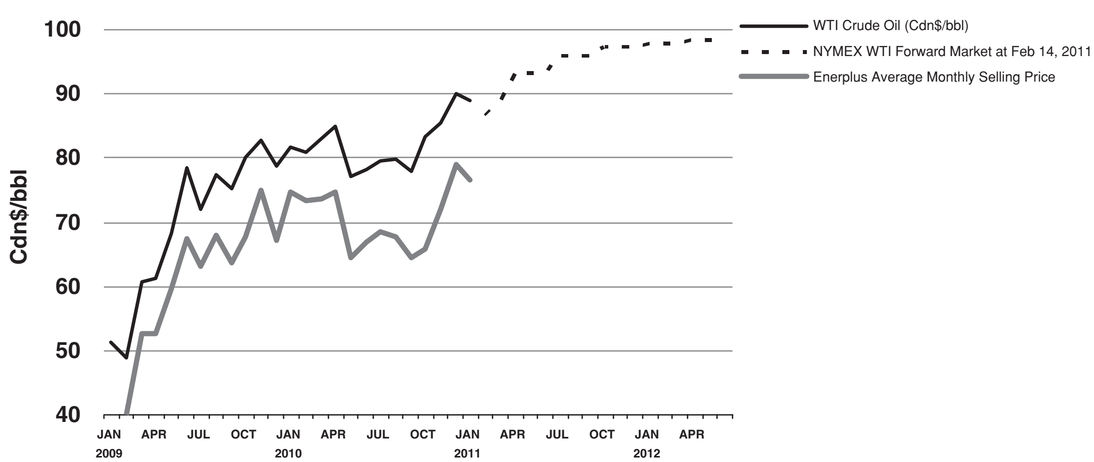


Crude Oil

Crude oil prices increased throughout 2010 from an average WTI price of US$78.40/bbl in January to US$89.23/bbl in December 2010. Stabilization of the global economy and forecasts of incremental demand helped support the oil price recovery. In the fourth quarter of 2010 prices rallied in response to a weaker U.S. dollar and strengthening U.S. equity markets.

As a portion of our oil production is sold in the U.S., we expect the change in our realized price to fall between the change in the U.S. and Canadian dollar equivalent benchmark WTI prices. The average price received for our crude oil (net of transportation costs) was $70.38/bbl during 2010, a 20% increase over 2009. This was in-line with expectations as the WTI price, after adjusting for the change in the US$/CDN$ dollar exchange rate, increased 17% year-over-year while the WTI price in U.S. dollars increased by 29%.

Monthly Crude Oil Prices



Price Risk Management

We continue to adjust our price risk management program with consideration given to our overall financial position together with the economics of our development capital program and potential acquisitions. Consideration is also given to the costs of our risk management program as we seek to limit our exposure to price downturns. We have continued to add crude oil hedge positions for 2011 and 2012 however we have been reluctant to add additional natural gas hedge positions due to the low forward price for natural gas. See Note 13 for a detailed list of our current price risk management positions.

The following is a summary of the financial contracts in place at February 14, 2011 expressed as a percentage of our forecasted net production volumes:

	Natural Gas (CDN$/Mcf)	Crude Oil (US$/bbl)	
	January 1, 2011 – March 31, 2011	January 1, 2011 – December 31, 2011	January 1, 2012 – December 31, 2012
Sold Puts (limiting downside protection)	$ 4.15	$ 56.50	–
% of forecasted 2011 net production	26%	11%	–
Swaps (fixed price)	$ 6.39	$ 87.27	$ 94.60
% of forecasted 2011 net production	33%	58%	20%
Purchased Calls (repurchasing upside)	$ 6.48	$ 101.17	–
% of forecasted 2011 net production	26%	11%	–

Based on weighted average price (before premiums), estimated 2011 average annual production of 78,000 to 80,000 BOE/day, net of royalties and assuming a 20% royalty rate.

Accounting for Price Risk Management

During 2010 our price risk management program generated cash gains of $67.3 million on our natural gas contracts and cash losses of $17.6 million on our crude oil contracts. In comparison, in 2009 we experienced cash gains of $74.8 million and $81.0 million respectively. The cash gains in 2010 are due to contracts which provided floor protection above market prices whereas the cash losses are a result of crude oil prices rising above our swap positions.

As the forward markets for natural gas and crude oil fluctuate, new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At December 31, 2010 the fair value of our natural gas and crude oil derivative instruments, net of premiums, represented a gain of $12.6 million and loss of $38.3 million respectively. The gain is recorded as a current deferred financial asset and the loss is recorded as a current deferred financial liability on our balance sheet. In comparison, at December 31, 2009 the fair value of our natural gas and crude oil derivative instruments represented gains of $20.4 million and losses of $20.3 million respectively. The change in the fair value of our commodity derivative instruments during 2010 resulted in unrealized losses of $7.7 million for natural gas and $18.0 million for crude oil. See Note 13 for details.

The following table summarizes the effects of our financial contracts on income for the years ended December 31, 2010 and 2009:

Risk Management Costs ($ millions, except per unit amounts)	**2010**		**2009**	
Cash gains/(losses):				
Natural gas	**$ 67.3**	**$ 0.64/Mcf**	$ 74.8	$ 0.63/Mcf
Crude oil	**(17.6)**	**$ (1.55)/bbl**	81.0	$ 6.73/bbl
Total cash gains/(losses)	**$ 49.7**	**$ 1.64/BOE**	$ 155.8	$ 4.66/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – natural gas	**$ (7.7)**	**$ (0.07)/Mcf**	$ (3.9)	$ (0.03)/Mcf
Change in fair value – crude oil	**(18.0)**	**$ (1.58)/bbl**	(117.0)	$ (9.72)/bbl
Total non-cash gains/(losses)	**$ (25.7)**	**$ (0.85)/BOE**	$ (120.9)	$ (3.62)/BOE
Total gains/(losses)	**$ 24.0**	**$ 0.79/BOE**	$ 34.9	$ 1.04/BOE

Cash Flow Sensitivity

The sensitivities below reflect all commodity contracts as listed in Note 13 and are based on forward markets as at February 14, 2011. To the extent the market price of crude oil and natural gas change significantly from current levels, the sensitivities will no longer be relevant as the effect of our commodity contracts will change.

Sensitivity Table	Estimated Effect on 2011 Cash Flow per Trust Unit(1)
Change of $0.50 per Mcf in the price of AECO natural gas	$ 0.18
Change of US$5.00 per barrel in the price of WTI crude oil	$ 0.09
Change of 1,000 BOE/day in production	$ 0.08
Change of $0.01 in the US$/CDN$ exchange rate	$ 0.06
Change of 1% in interest rate	$ 0.03

(1) Assumes 178,939,000 shares outstanding.

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

Revenues

Crude oil and natural gas revenues in 2010 were $1,300.2 million ($1,327.1 million, net of $26.9 million of transportation costs), an increase of 5% compared to $1,232.8 million ($1,259.2 million, net of $26.4 million of transportation costs) during 2009. This increase was due to higher commodity prices, most significantly oil, partially offset by lower production.

Analysis of Sales Revenue(1) ($ millions)	Crude Oil	NGLs	Natural Gas	Total
2009 Sales Revenue	$ 704.8	$ 63.0	$ 465.0	$ 1,232.8
Price variance(1)	134.6	14.1	14.8	163.5
Volume variance	(39.5)	(4.1)	(52.5)	(96.1)
2010 Sales Revenue	**$ 799.9**	**$ 73.0**	**$ 427.3**	**$ 1,300.2**

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

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. Total royalties paid during 2010 increased to $223.5 million from $207.5 million in 2009, primarily due to higher commodity prices partially offset by lower production volumes. As a percentage of oil and gas sales, net of transportation costs, royalties in both 2010 and 2009 were approximately 17%. We expect this percentage to increase to approximately 20% during 2011 due to the increased oil weighting within our portfolio combined with additional production in the U.S. Royalty rates in the U.S., including state production taxes, have typically averaged 24% of sales compared to recent Canadian rates of approximately 16%.

Operating Expenses

Operating expenses during 2010 were $289.5 million or $9.54/BOE compared to $327.2 million or $9.79/BOE during 2009. Operating costs were lower compared to 2009 due to the impact of our divestment program, as we disposed of higher operating cost properties, along with lower repairs and maintenance spending. Operating costs were lower than our guidance of $10.20/BOE primarily due to non-cash gains on our power contracts and unanticipated equalization credits recorded during the fourth quarter.

For 2011 we expect to see a further reduction in operating costs to approximately $9.20/BOE due to the full year impact of our higher operating cost divestments combined with additional production from our Fort Berthold and Marcellus plays where operating costs are significantly lower than our corporate average.

General and Administrative Expenses ("G&A")

G&A expenses including corporate conversion costs were $2.60/BOE or $78.9 million during 2010, between our 2010 guidance of $2.55/BOE and $2.64/BOE experienced in 2009. G&A expenses in 2010 were $9.4 million less than 2009 however, they were comparable on a BOE basis due to lower production in 2010. Our 2010 G&A expenses increased in the fourth quarter primarily due to an 16% increase in our unit price during this time which increased our long-term compensation expense. During 2010 we also incurred $3.3 million of corporate conversion costs to simplify our corporate structure and facilitate the conversion from a trust to a corporation. One-time costs of $11.1 million recorded in 2009 were associated with staff reductions and transaction costs related to the issuance of our senior notes.

G&A expenses included non-cash G&A charges of $5.9 million or $0.20/BOE compared to $6.5 million or $0.20/BOE for 2009. These amounts relate solely to our trust unit rights incentive plan and are determined using a binomial lattice option-pricing model. See Note 11 for further details.

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

General and Administrative Costs ($ millions)		**2010**		**2009**
Cash	**$**	**69.7**	$	70.7
Corporate conversion and other one-time items		**3.3**		11.1
Trust unit rights incentive plan (non-cash)		**5.9**		6.5
Total G&A	**$**	**78.9**	$	88.3

(Per BOE)		**2010**		**2009**
Cash	**$**	**2.29**	$	2.11
Corporate conversion and other one-time items		**0.11**		0.33
Trust unit rights incentive plan (non-cash)		**0.20**		0.20
Total G&A	**$**	**2.60**	$	2.64

We have been actively working to improve not only our underlying asset base, but also our internal technical capabilities. Throughout 2010 we increased our staffing levels within our U.S. operations by 50% in order to effectively manage our growing portfolio in the Bakken and the Marcellus plays and have continued to enhance our technical capabilities within our Canadian operations. These changes will result in an increase in our G&A expense during 2011.

The adoption of International Financial Reporting Standards ("IFRS") will also impact our G&A expenses going forward. Previously staff costs associated with our acquisition and divestment activities were capitalized, however under IFRS these costs will now be expensed and are expected to increase our 2011 G&A expenses by $0.20/BOE.

As a result of these changes and lower annual average production volumes in 2011 we expect G&A costs will average approximately $3.30/BOE. As our capital plans are executed and production volumes increase throughout 2011 and into 2012, we expect to see a reduction in G&A expenses per BOE.

Interest Expense

Interest expense includes interest on long-term debt, the premium amortization on our US$175 million senior unsecured notes, unrealized gains and losses resulting from the change in fair value of our interest rate swaps as well as the interest component on our cross currency interest rate swap ("CCIRS"). See Note 9 for further details.

Interest on long-term debt during 2010 totaled $47.0 million, a $16.4 million increase from $30.6 million in 2009. This increase is due to higher average indebtedness year over year, the full year impact of higher interest rates associated with our senior unsecured notes issued in June 2009 and increased fees on our credit facility in 2010 after the renewal on June 30. Interest expense for 2010 also included a $5.0 million extension fee in conjunction with our credit facility renewal. Our weighted average interest rate was 4.9% in 2010 compared to 4.2% in 2009.

For the year ended December 31, 2010 non-cash interest gains were $0.3 million compared to non-cash losses of $25.7 million in 2009. The changes in the fair value of our interest rate swaps and the interest component on our CCIRS cause non-cash interest to fluctuate between periods.

The following table summarizes the cash and non-cash interest expense:

Interest Expense ($ millions)		**2010**		**2009**
Interest on long-term debt	**$**	**47.0**	$	30.6
Non-cash interest loss/(gain)		**(0.3)**		25.7
Total Interest Expense	**$**	**46.7**	$	56.3

Approximately 59% of our debt was based on fixed interest rates while 41% had floating interest rates at December 31, 2010. In comparison, at December 31, 2009 approximately 77% of our debt was based on fixed interest rates and 23% was floating.

Foreign Exchange

During the year we realized foreign exchange losses of $28.0 million compared to gains of $18.5 million in 2009. Enerplus' foreign exchange gains and losses typically originate from our U.S. dollar denominated transactions with our U.S. subsidiary. The U.S. dollar depreciated against the Canadian dollar during 2009 and continued to lose ground in 2010. During 2009 our Canadian operating entity had net U.S. dollar payables which resulted in realized foreign exchange gains. However, during 2010 we had net U.S. dollar receivables and the continued weakening of the U.S. dollar resulted in realized foreign exchange losses. In addition, on June 19, 2010 we made our first principle repayment on our US$175 million senior notes. As a result of the underlying CCIRS on these notes, which fixed the principal repayment at a foreign exchange rate of 0.6522 US$/CDN$, we realized a foreign exchange loss of $18.0 million and a corresponding non-cash gain of $18.0 million.

Unrealized foreign exchange gains in 2010 totaled $28.9 million compared to $41.1 million in 2009. Unrealized foreign exchange gains and losses occur on the translation of our U.S. dollar denominated debt as well as on the mark to market of our CCIRS and foreign exchange swaps. See Note 10 for further details.

Foreign Exchange ($ millions)		**2010**		**2009**
Realized foreign exchange loss/(gain)	**$**	**28.0**	$	(18.5)
Unrealized foreign exchange loss/(gain)		**(28.9)**		(41.1)
Total Foreign Exchange loss/(gain)	**$**	**(0.9)**	$	(59.6)

Capital Expenditures

Development Capital Spending

During 2010 our development capital spending totaled $542.7 million, net of DRCs of $18.3 million. This represents a $243.6 million or an 81% increase from 2009 levels as we increased spending on our early stage growth assets. Our 2010 spending was $27.7 million above our guidance of $515 million, approximately $20.0 million of which related to the Marcellus play. We incurred additional completion costs as we increased the lateral length along with the number of frac stages in several wells. We also experienced some cost inflation in the Marcellus due to the high levels of activity in the area and demand for services. In Canada, we accelerated our capital spending at Tommy Lakes by approximately $4.0 million along with lower than expected DRCs of approximately $8.0 million. These increases were somewhat offset by completion delays on wells in Fort Berthold.

Property Acquisitions and Dispositions

In support of our strategy to reposition our portfolio and improve our focus and profitability we successfully completed $1.0 billion of acquisitions and $871.5 million of dispositions during 2010. When we initiated this strategy in 2009, we acquired new properties totaling $272.0 million and disposed of $104.3 million of assets. Our acquisitions in 2010 related primarily to undeveloped land in both Canada and the U.S. that are expected to add production and reserves in the years ahead. In 2010, we acquired 58,921 net acres in the Fort Berthold play for US$588.0 million which also included production of 1,900 BOE/day. In addition we added 75,317 net acres (70,833 operated) to our existing land position in the Marcellus play for $169.3 million and fulfilled $92.3 million in carry obligation. In Canada, we purchased 104,500 net acres of prospective land contiguous to our existing holdings in the Freda Lake, Neptune and Oungre areas of the Saskatchewan Bakken for $118.7 million. We also acquired 36,100 net acres of undeveloped land in the British Columbia and Alberta Deep Basin for $25.9 million. Our 2010 acquisitions are listed below:

Play Type		Amount CDN (millions)(1)	Net Acreage	Production (BOE/day)
U.S. Acquisitions				
Fort Berthold	$	588.0	58,921	1,900
Marcellus		169.3	75,317	–
Marcellus carry spending		92.3	–	–
Other		10.5	3,750	–
Total U.S.	**$**	**860.1**	**137,988**	**1,900**
Canadian Acquisitions				
Bakken	$	118.7	104,500	–
Deep Basin Gas		25.9	36,100	–
Other		13.4	3,400	–
Total Canadian	**$**	**158.0**	**144,000**	–
Total Acquisitions	**$**	**1,018.1**	**281,988**	**1,900**

(1) Net of closing adjustments.

Our dispositions in 2010 included $465.2 million in proceeds from three non-core property packages representing approximately 10,400 BOE/day of production and $404.8 million in proceeds from the sale of our 100% working interest in the Kirby oil sands lease.

In 2009 we acquired Bakken land interests in North Dakota and Southeast Saskatchewan as well as a 21.5% non-operated working interest in the Marcellus shale gas play. Total consideration for the Marcellus acquisition was US$411 million, comprised of US$164.4 million in cash that was paid upon closing and US$246.6 million to be paid over time as 50% of the operator's future drilling and completion costs. At December 31, 2010 our remaining Marcellus carry commitment was US$147.0 million compared to US$237.3 million at December 31, 2009.

Our 2009 divestments related mainly to the sale of a non-core oil property in Western Canada for proceeds of $101.0 million.

Total net capital expenditures for 2010 and 2009 are outlined below:

Capital Expenditures ($ millions)		2010		2009
Development expenditures(1)(2)	**$**	**457.4**	$	231.8
Plant and facilities		**85.3**		67.3
Development Capital		**542.7**		299.1
Office		**4.0**		6.7
Sub-total		**546.7**		305.8
Property acquisitions(2)(3)		**1,018.1**		272.0
Property dispositions(3)		**(871.5)**		(104.3)
Total Net Capital Expenditures	**$**	**693.3**	$	473.5

(1) Development expenditures are net of DRCs.
(2) Land acquisitions in prior periods have been reclassified from development capital expenditures to property acquisitions to conform with the current year presentation.
(3) Net of post-closing adjustments.

We expect development capital spending in 2011 will be approximately $650 million with 65% projected to be invested in oil projects. We expect to focus approximately 85% of our spending on our Bakken, Waterflood and Marcellus resource plays. With continued low natural gas prices the majority of our natural gas spending will be directed to our non-operated Marcellus interest to further delineate the resource and preserve our lease positions.

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

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For 2010 DDA&A was $645.3 million or $21.27/BOE compared to $650.4 million or $19.45/BOE in 2009. The increase in our 2010 DDA&A is attributable to a higher depletion rate due to negative reserve revisions experienced at December 31, 2009.

No impairment of the Fund's PP&E values existed at December 31, 2010 using year-end reserves and management's estimates of future prices. Our future price estimates are more fully discussed in Note 5.

Goodwill

The goodwill balance of $599.7 million is a result of previous corporate acquisitions and represents the excess of the total purchase price over the fair value of the net identifiable assets and liabilities acquired. The goodwill balance with respect to our U.S operations is exposed to foreign currency fluctuations as it is translated into Canadian dollars at the period end exchange rate. No goodwill impairment existed as of December 31, 2010.

Asset Retirement Obligations

In connection with our operations, we will incur abandonment and reclamation costs for our assets including surface leases, wells, facilities and pipelines. Total future asset retirement obligations 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 asset retirement obligations to be $208.7 million at December 31, 2010 compared to $230.5 million at December 31, 2009, based on total undiscounted liabilities of $590.2 million and $676.8 million respectively. The majority of the decrease in 2010 related to asset retirement obligations associated with our non-core divestments. See Note 7 for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2010 we spent $17.2 million (2009 – $13.8 million) on our asset retirement obligations and we expect to spend approximately $19.0 million in 2011. Our abandonment and reclamation costs are expected to be incurred over the next 66 years with the majority between 2031 and 2050. We do not reserve cash or assets for the purpose of funding our future asset retirement obligations. Any reclamation or abandonment costs incurred will generally be funded out of cash flow. If we are unable to remedy an environmental claim we may be required to suspend operations or enter into interim compliance measures pending satisfactory resolution of the matter.

There are uncertainties related to asset retirement obligations and the impact on the financial statements could be material as the eventual timing and costs for the obligations could differ from our estimates. Factors that could cause our estimates to differ include any changes to laws or regulations, reserve estimates, costs and technology.

Environment

Our operations are subject to laws and regulations concerning pollution, protection of the environment and the handling of hazardous materials and waste. These laws require us to remedy the effect of our activities on the environment at our operating sites including dismantling production facilities and remediating any damage caused by the release of substances. We are seeing an increase in the number of regulations related to environmental compliance along with stricter thresholds within the regulations. Compliance with this legislation may require significant expenditures.

Specific greenhouse gas ("GHG") regulations have been enacted in Alberta and British Columbia and the cost of our compliance in 2010 was approximately $0.9 million. Federal GHG regulations have not been finalized however we do not expect a material impact on our business given our current operations. We would also anticipate a transition period once the regulations are finalized to provide companies the opportunity to modify their operations and practices. In the United States, the federal Environmental Protection Agency has issued a GHG reporting and tailoring rule and we do not expect the rule to have a material impact on our operations. The uncertainty surrounding the direction from various levels of government affects our ability to manage potential risks and opportunities associated with GHG emissions from our operations.

We may be subject to remedial environmental and litigation costs resulting from unknown and unforeseeable environmental impacts arising from our operations. There are inherent risks of oil spills and pipeline leaks at our operating sites and clean-up costs may be significant. We have active site inspection and corrosion risk management programs along with asset integrity management designed to ensure compliance with regulations and reduce the number of incidences. We also carry pollution insurance to help mitigate the cost of spills should they occur.

Taxes

Future Income Taxes

Future income taxes arise from differences between the accounting and tax basis of assets and liabilities. The balance will be realized over time as future income tax assets and liabilities are realized or settled.

The future income tax recovery for 2010 was $54.8 million compared to $93.2 million in 2009. The decrease in the future income tax recovery was a result of higher net income in our operating entities during 2010 compared to 2009.

Current Income Taxes

Under the income trust structure, in effect prior to January 1, 2011, payments were made between our operating entities and the Fund, which ultimately transferred both income and future income tax liability to our unitholders. As a result minimal cash income taxes were generally paid by our Canadian operating entities. Effective January 1, 2011 we are subject to normal Canadian corporate taxes as a result of our conversion. However, we do not expect to pay cash taxes in Canada prior to 2013 as we have $2.0 billion of tax pools to offset taxable income. This estimate may vary depending on numerous factors, including fluctuations in commodity prices and acquisition and disposition activity.

We are subject to normal course income tax audits by various taxation authorities. During the fourth quarter of 2010 we recorded a $16.6 million provision and corresponding charge to current income tax expense with respect to an ongoing income tax audit of a predecessor company from a prior corporate acquisition. At this time we are uncertain of the timing and final outcome of this matter.

During 2010 our U.S. operations recorded a current income tax recovery in the amount of $46.9 million compared to a current income tax expense of $0.2 million in 2009. The 2010 recovery is due to higher capital spending levels in 2010 which has resulted in a tax loss that we plan to carry back to recover prior period cash income taxes. We expect to pay a nominal amount of U.S. cash taxes in 2011.

Tax Pools

We estimate our tax pools at December 31, 2010 to be as follows:

Pool Type ($ millions)		**Total**
COGPE	$	**475**
CDE		**178**
UCC		**498**
CEE		**151**
Tax losses and other		**669**
Canadian tax pools	$	**1,971**
US tax pools		**1,167**
Total	$	**3,138**

Net Income

Net income in 2010 was $127.1 million or $0.72 per trust unit compared to $89.1 million or $0.53 per trust unit in 2009. The increase was primarily due to a $67.4 million increase in oil and gas sales, net of transportation, and a $37.7 million decrease in operating costs, partially offset by decreased foreign exchange gains of $58.6 million.

Cash Flow from Operating Activities

Cash flow from operating activities in 2010 was $703.1 million or $3.96 per trust unit compared to $775.8 million or $4.58 per trust unit in 2009. The decrease was primarily due to lower cash gains on our commodity derivative instruments, higher realized foreign exchange losses and increased working capital. This was partially offset by higher oil and gas sales and lower operating expenses.

Selected Financial Results

Per BOE of production (6:1)	Year ended December 31, 2010 Operating Cash Flow[(1)]	Year ended December 31, 2010 Non-Cash & Other Items	Year ended December 31, 2010 Total	Year ended December 31, 2009 Operating Cash Flow[(1)]	Year ended December 31, 2009 Non-Cash & Other Items	Year ended December 31, 2009 Total
Production per day			**83,139**			91,569
Weighted average sales price[(2)]	**$ 42.85**	**$ –**	**$ 42.85**	$ 36.89	$ –	$ 36.89
Royalties	**(7.37)**	**–**	**(7.37)**	(6.21)	–	(6.21)
Commodity derivative instruments	**1.64**	**(0.85)**	**0.79**	4.66	(3.62)	1.04
Operating costs	**(9.61)**	**0.07**	**(9.54)**	(9.71)	(0.08)	(9.79)
General and administrative expenses	**(2.40)**	**(0.20)**	**(2.60)**	(2.44)	(0.20)	(2.64)
Interest, foreign exchange and other expenses	**(1.85)**	**0.37**	**(1.48)**	(0.34)	0.39	0.05
Current income tax	**1.00**	**–**	**1.00**	(0.01)	–	(0.01)
Restoration and abandonment cash costs	**(0.57)**	**0.57**	**–**	(0.41)	0.41	–
Depletion, depreciation, amortization and accretion	**–**	**(21.27)**	**(21.27)**	–	(19.45)	(19.45)
Future income tax (expense)/recovery	**–**	**1.81**	**1.81**	–	2.79	2.79
Total per BOE	**$ 23.69**	**$ (19.50)**	**$ 4.19**	$ 22.43	$ (19.76)	$ 2.67

(1) Cash Flow from Operating Activities before changes in non-cash operating working capital.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

The following table provides a geographical analysis of key operating and financial results for 2010 and 2009.

	Year ended December 31, 2010			Year ended December 31, 2009		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Natural gas (Mcf/day)	**266,671**	**22,021**	**288,692**	312,846	13,724	326,570
Crude oil (bbls/day)	**21,712**	**9,423**	**31,135**	24,800	8,184	32,984
Natural gas liquids (bbls/day)	**3,889**	**–**	**3,889**	4,157	–	4,157
Total daily sales (BOE/day)	**70,046**	**13,093**	**83,139**	81,098	10,471	91,569
Pricing[1]						
Natural gas (per Mcf)	**$ 3.94**	**$ 5.42**	**$ 4.05**	$ 3.86	$ 5.11	$ 3.91
Crude oil (per bbl)	**$ 70.05**	**$ 71.15**	**$ 70.38**	$ 58.59	$ 58.41	$ 58.54
Natural gas liquids (per bbl)	**$ 51.41**	**$ –**	**$ 51.41**	$ 41.54	$ –	$ 41.54
Capital Expenditures						
Development capital and office	**$ 307.2**	**$ 239.5**	**$ 546.7**	$ 258.4	$ 47.4	$ 305.8
Acquisitions of oil and gas properties	**$ 158.0**	**$ 860.1**	**$ 1,018.1**	$ 34.5	$ 237.5	$ 272.0
Dispositions of oil and gas properties	**$ (871.5)**	**$ –**	**$ (871.5)**	$ (104.3)	$ –	$ (104.3)
Revenues						
Oil and gas sales[1]	**$ 1,011.9**	**$ 288.3**	**$ 1,300.2**	$ 1,032.7	$ 200.1	$ 1,232.8
Royalties[2]	**$ (154.7)**	**$ (68.8)**	**$ (223.5)**	$ (161.9)	$ (45.6)	$ (207.5)
Commodity derivative instruments gain/(loss)	**$ 24.0**	**$ –**	**$ 24.0**	$ 34.9	$ –	$ 34.9
Expenses						
Operating	**$ 271.3**	**$ 18.2**	**$ 289.5**	$ 313.0	$ 14.2	$ 327.2
General and administrative	**$ 67.5**	**$ 11.4**	**$ 78.9**	$ 81.1	$ 7.2	$ 88.3
Depletion, depreciation, amortization and accretion	**$ 544.8**	**$ 100.5**	**$ 645.3**	$ 567.2	$ 83.2	$ 650.4
Current income taxes (recovery)/expense	**$ 16.6**	**$ (47.0)**	**$ (30.4)**	$ –	$ 0.2	$ 0.2

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

THREE YEAR SUMMARY OF KEY MEASURES

Crude oil and natural gas sales increased for the first half of 2008 due to increased commodity prices and increased production from the Focus acquisition which we completed in February 2008. Oil and natural gas sales decreased in the latter part of 2008 with the sharp decline in commodity prices and were flat during 2009 and 2010 as rising crude oil prices have largely been offset by declining natural gas prices and production levels as a result of disposition activity.

Net income has been affected by fluctuating commodity prices and risk management costs, the fluctuating Canadian dollar and changes in future tax provisions. The following table provides a summary of net income, cash flow and other key measures.

($ millions, except per unit amounts)	2010	2009	2008
Oil and gas sales[(1)]	**$ 1,300.2**	$ 1,232.8	$ 2,304.2
Net income	**127.1**	89.1	888.9
Per unit (Basic)[(2)]	**0.72**	0.53	5.54
Per unit (Diluted)[(2)]	**0.71**	0.53	5.53
Cash flow from operating activities	**703.1**	775.8	1,262.8
Per unit (Basic)[(2)]	**3.96**	4.58	7.86
Cash distributions to unitholders[(3)]	**384.1**	368.2	786.1
Per unit (Basic)[(2)(3)]	**2.16**	2.17	4.89
Payout ratio[(4)]	**55%**	47%	62%
Adjusted payout ratio[(4)]	**132%**	87%	109%
Total assets	**5,835.2**	5,905.5	6,230.1
Long-term debt, net of cash[(5)]	**724.0**	485.3	657.4

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Based on weighted average trust units outstanding.
(3) Calculated based on distributions paid or payable. Cash distributions to unitholders per unit may not correspond to actual distributions as a result of using the annual weighted average trust units outstanding.
(4) Payout ratio is calculated as cash distributions to unitholders divided by cash flow from operating activities. Adjusted payout ratio is calculated as the sum of cash distributions to unitholders plus development capital and office expenditures divided by cash flow from operating activities. See "Non-GAAP Measures" above.
(5) Including current portion of long-term debt

LIQUIDITY AND CAPITAL RESOURCES

Debt

During the second quarter we extended our unsecured, covenant-based bank credit facility for a three year term, maturing June 30, 2013. Based on our forecasted cash requirements, our anticipated ongoing access to debt and equity markets, combined with the significant increase in standby credit charges, we chose to reduce our facility size from $1.4 billion to $1.0 billion. Drawn fees under the facility range between 200 and 375 basis points over bankers' acceptance rates whereas previously they ranged from 55 to 110 basis points. We are currently paying 200 basis points over bankers' acceptance rates which have been trading around 1%. Standby fees on the undrawn portion of the facility are based on 25% of the drawn pricing. We have the ability to request an extension of the facility each year or repay the entire balance at the end of the term. A fee of $5.0 million was paid to extend the facility for three years and was recorded in interest expense during the second quarter. The amending agreement was filed on July 21, 2010 as a "Material Document" on the Fund's' SEDAR profile at www.sedar.com.

On June 19, 2010 we settled our first principal payment on the US$175 million senior notes and associated cross currency interest rate swap principal settlement for a total of $53.7 million. See "Commitments" and Notes 8 and 13 for more information.

Total debt at December 31, 2010 was $732.4 million, an increase of $173.5 million from $558.9 million at December 31, 2009, which includes the current portion of our senior notes. Long-term debt at December 31, 2010 was comprised of $234.7 million of bank indebtedness and $497.7 million of senior notes. The increase of $173.5 million in 2010 is mainly the result of our increased development capital spending throughout the year.

Our working capital at December 31, 2010, excluding cash, current deferred financial assets and credits, current portion of long-term debt and future income taxes decreased by $64.9 million compared to December 31, 2009. This change was due to increased payables related to our development capital spending during the fourth quarter, along with decreased receivables due to lower production in December 2010. We expect to finance our negative working capital with our cash flow or bank indebtedness.

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

Financial Leverage and Coverage	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Long-term debt to cash flow (12 month trailing)(1)	**1.0 x**	0.6 x
Cash flow to interest expense (12 month trailing)(2)	**15.0 x**	25.4 x
Long-term debt to long-term debt plus equity(1)	**16%**	10%

(1) Long-term debt including current portion is measured net of cash.
(2) Interest expense excluding non-cash items.

Payments with respect to the bank facilities, senior notes and other third party debt have priority over claims of and future dividends to our shareholders. At December 31, 2010, we were in compliance with our debt covenants, the most restrictive of which limits our long-term debt to three times trailing cash flow.

We expect to have adequate liquidity from cash flow and our bank credit facility to fund planned development capital spending and working capital requirements for 2011. Our capital spending and dividends are expected to exceed our cash flow in 2011 and 2012, however our balance sheet provides us the flexibility to support these plans. We expect that our debt-to-cash flow ratio will increase during this time as we continue to invest in earlier stage growth assets where there is a longer lead time to production and cash flow. We will be actively monitoring our debt levels and may consider selling non-cash generating assets or selling part of our non-operated Marcellus interests to manage our debt and maintain our financial flexibility. Our debt-to-cash flow levels are anticipated to decrease after 2012 as production and cash flow from our growth plays accelerates.

Counterparty Credit

Oil and Gas Sales Counterparties

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

Financial Derivative Counterparties

We are exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. We mitigate this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the majority of our financial counterparties. These agreements provide some credit protection by generally allowing parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. To date we have not experienced any losses due to non-performance by our derivative counterparties. At December 31, 2010 we had $13.0 million in mark-to-market assets offset by $103.6 million of mark-to-market liabilities resulting in a net liability position of $90.6 million.

Cash Flow from Operating Activities, Cash Distributions and Payout Ratio

Cash flow from operating activities ("cash flow") and cash distributions are reported on the Consolidated Statements of Cash Flows. During 2010 cash distributions of $384.1 million were funded entirely through cash flow of $703.1 million.

Our payout ratio, which is calculated as cash distributions divided by cash flow, was 55% for 2010 compared to 47% in 2009. Our adjusted payout ratio, which is calculated as cash distributions plus development capital and office expenditures divided by cash flow, was 132% for

2010 compared to 87% in 2009. Our adjusted payout ratio increased during 2010 mainly due to higher capital spending levels which included spending on earlier stage growth assets that did not generate immediate production or cash flow. See "Non-GAAP Measures" above.

The following table compares cash distributions to cash flow and net income.

($ millions, except per unit amounts)	2010	2009	2008
Cash flow from operating activities	**$ 703.1**	$ 775.8	$ 1,262.8
Cash distributions	**384.1**	368.2	786.1
Excess of cash flow over cash distributions	**$ 319.0**	$ 407.6	$ 476.7
Net income	**$ 127.1**	$ 89.1	$ 888.9
(Shortfall)/excess of net income over cash distributions	**$ (257.0)**	$ (279.1)	$ 102.8
Cash distributions per weighted average trust unit	**$ 2.16**	$ 2.17	$ 4.89
Payout ratio(1)	**55%**	47%	62%
Adjusted payout ratio(1)	**132%**	87%	109%

(1) Payout ratio is calculated as cash distributions to unitholders divided by cash flow from operating activities. Adjusted payout ratio is calculated as the sum of cash distributions to unitholders plus development capital and office expenditures divided by cash flow from operating activities. See "Non-GAAP Measures" above.

Dividend Policy

As a corporation we pay monthly dividends whereas we previously paid monthly distributions as an income trust. We intend to continue to distribute a significant portion of our cash flow to our shareholders and we currently pay a monthly dividend of $0.18/share. We will continue to assess dividend levels with respect to anticipated cash flows, debt levels and service requirements, capital spending plans and capital market conditions and will adjust dividend levels as necessary. The payment of dividends, or the amount thereof, is not guaranteed.

COMMITMENTS

We have contracted to transport 200 MMcf/day of natural gas in Canada with contract terms that range anywhere from one month to five years. We have also contracted 6,000 MMbtu/day gas gathering capacity for our Marcellus production, which increases to 13,650 MMbtu/day on June 1, 2011 until March 31, 2022. In addition we have contracted for 4,500 MMbtu/day of transportation capacity on Columbia Gas Transmission for our Marcellus sales gas until January 2014.

We have contracted for 1,000 bbl/day of transportation capacity for our Bakken crude oil in the U.S. beginning May 2011 for five years with an additional 5,000 bbl/day beginning January 1, 2013 for five years.

Our gas supply dedicated to aggregator sales contracts is expected to be approximately 7% of gas production or 21 MMcf/day. Under these arrangements, we receive a price based on the average netback price of the pool.

We have also entered into contracts to secure a drilling rig and related fracturing services for two years commencing in early 2011 for our U.S. Bakken play. Our minimum commitment is approximately $4.6 million per month for these contracts.

Our U.S. and Canadian office leases expire in 2011 and 2014 respectively. Annual costs of these lease commitments include rent and operating fees. Our commitments, contingencies and guarantees are more fully described in Note 14.

As at December 31, 2010 we have the following minimum annual commitments including long-term debt:

($ millions)	Total	Minimum Annual Commitment Each Year					Total Committed after 2015
		2011	2012	2013	2014	2015	
Bank credit facility	**$ 234.7**	$ –	$ –	$ 234.7	$ –	$ –	$ –
Senior unsecured notes(1)(2)	**573.1**	64.6	64.6	64.6	64.7	90.8	223.8
Pipeline commitments	**82.8**	16.8	12.6	14.0	12.4	11.5	15.5
Processing commitments	**20.3**	3.5	3.6	1.6	1.6	1.6	8.4
Marcellus carry commitment(4)	**146.2**	116.0	30.2	–	–	–	–
Drilling and completions commitment(5)	**110.6**	42.7	55.3	12.6	–	–	–
Asset retirement obligations(6)	**590.2**	19.0	20.0	20.4	20.4	20.4	490.0
Office lease	**44.6**	11.3	11.4	11.4	10.5	–	–
Total commitments(3)	**$ 1,802.5**	$ 273.9	$ 197.7	$ 359.3	$ 109.6	$ 124.3	$ 737.7

(1) Interest payments have not been included.
(2) Includes the economic impact of derivative instruments directly related to the senior unsecured notes (CCIRS and foreign exchange swap – see Note 13).
(3) Crown and surface royalties, lease rentals, mineral taxes, and abandonment and reclamation costs (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(4) The Marcellus carry commitment is based on estimated capital spending plans and has been converted to CDN$ using the December 31, 2010 foreign exchange rate of 1.0054.
(5) US$ commitments have been converted to CDN$ using the December 31, 2010 foreign exchange rate of 1.0054.
(6) Based upon current spending estimates.

ACCUMULATED DEFICIT

We have historically paid cash distributions in excess of accumulated earnings as cash distributions are based on the actual cash flow generated in the period, whereas accumulated earnings are based on net income which includes non-cash items such as DDA&A charges, derivative instrument mark-to-market gains and losses, unit based compensation charges and future income tax provisions.

TRUST UNIT INFORMATION

We had 178,648,000 trust units outstanding at December 31, 2010 compared to 177,061,000 trust units outstanding at December 31, 2009. At December 31, 2010 this included 4,007,000 exchangeable limited partnership units which were convertible at the option of the holder into 0.425 of an Enerplus trust unit (1,703,000 trust units). During 2010, a total of 2,375,000 partnership units were converted into 1,009,000 trust units.

During 2010, 1,587,000 trust units (2009 – 1,065,000) were issued pursuant to the Trust Unit Monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP") and the trust unit rights incentive plan, net of redemptions. This resulted in $35.4 million (2009 – $24.2 million) of additional equity for the Company. See Note 11 for further details.

The weighted average basic number of trust units outstanding during 2010 was 177,737,000 compared to 169,280,000 trust units during 2009.

As a result of our conversion from an income trust into a corporation, all of our outstanding trust units were converted to common shares at a ratio of 1:1 and all outstanding exchangeable partnership units were converted to common shares on the basis of 0.425 of a common share for each partnership unit. At February 22, 2011 we had 178,939,000 common shares outstanding.

QUARTERLY FINANCIAL INFORMATION

Oil and natural gas sales were essentially flat during 2009 and 2010 as rising crude oil prices have largely been offset by declining natural gas prices. Our reduced production levels during the last two years have also put downward pressure on oil and gas sales.

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

(CDN$ millions, except per trust unit amounts)	Oil and Gas Sales(1)	Net Income/(Loss)	Net Income/(Loss) Per Trust Unit Basic	Net Income/(Loss) Per Trust Unit Diluted
2010				
Fourth Quarter	**$ 313.2**	**$ (1.0)**	**$ (0.01)**	**$ (0.01)**
Third Quarter	**305.5**	**16.8**	**0.09**	**0.09**
Second Quarter	**318.2**	**31.3**	**0.18**	**0.18**
First Quarter	**363.3**	**80.0**	**0.45**	**0.45**
Total	**$ 1,300.2**	**$ 127.1**	**$ 0.72**	**$ 0.71**
2009				
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.

SUMMARY FOURTH QUARTER INFORMATION

In comparing the fourth quarter of 2010 with the same period in 2009:

- Average daily production decreased 8% to 80,114 BOE/day primarily due to the divestment of approximately 10,400 BOE/day of non-core production during 2010.
- Cash flow decreased to $146.8 million from $188.6 million primarily due to lower natural gas prices and lower production.
- We realized a net loss of $1.0 million compared to net income of $2.7 million due to commodity derivative losses and lower oil and gas sales.
- Our payout ratio increased to 66% from 51% in 2009 as cash distributions per unit were held at $0.54 per unit despite lower cash flow. In addition, most of the Marcellus and Bakken capital spending in the fourth quarter is not expected to generate cash flow until 2011.
- Operating expenses, including non-cash amounts, decreased by 13% to $8.05/BOE from $9.30/BOE mainly due to the divestment of high operating cost non-core properties, lower power costs and equalization credits.
- G&A expenses, including non-cash amounts, decreased 9% to $3.20/BOE from $3.50/BOE mainly due to one-time costs related to staff reductions recorded during 2009.
- Development capital spending increased 93% to $229.0 million due to higher spending levels in the Bakken and Marcellus plays.
- Dispositions totaled $537.9 million, including $133.1 million for non-core conventional properties, as well as the disposition of our Kirby oil sands lease for proceeds of $404.8 million.
- Acquisitions totaled $524.3 million, including $468.7 million for an additional 46,500 acres of land in our Fort Berthold area.
- We made a $16.6 million current income tax provision in Canada with respect to a tax filing position taken by a predecessor company that is currently being audited by the tax authorities.
- We recorded a current income tax recovery of $13.6 million in the U.S. due to higher capital spending levels in 2010 resulting in a tax loss that we plan to carry back to prior years.

The following tables provide an analysis of key financial and operating results for the three months ended December 31, 2010 and 2009.

(CDN$ millions, except per unit amounts)	Three Months Ended December 31, 2010	Three Months Ended December 31, 2009
Financial		
Net Income/(loss)	**$ (1.0)**	$ 2.7
Cash Flow from Operating Activities	**$ 146.8**	$ 188.6
Cash Distributions to Unitholders[1]	**$ 96.4**	$ 95.5
Financial per Unit[2]		
Net Income/(loss)	**$ (0.01)**	$ 0.02
Cash Flow from Operating Activities	**$ 0.82**	$ 1.07
Cash Distributions to Unitholders[1]	**$ 0.54**	$ 0.54
Payout Ratio[3]	**66%**	51%
Adjusted Payout Ratio[3]	**223%**	114%
Average Daily Production	**80,114**	86,777
Selected Financial Results per BOE[4]		
Oil and Gas Sales[5]	**$ 42.49**	$ 41.75
Royalties	**(6.21)**	(6.56)
Commodity Derivative Instruments gains	**1.02**	3.34
Operating Costs	**(8.29)**	(9.27)
General and Administrative expenses	**(2.97)**	(3.30)
Interest and Foreign Exchange expenses	**(2.95)**	(0.72)
Taxes	**(0.40)**	0.66
Restoration and Abandonment costs	**(0.96)**	(0.64)
Cash Flow from Operating Activities before changes in non-cash working capital	**$ 21.73**	$ 25.26
Weighted Average Number of Units Outstanding (thousands)	**178,368**	176,872
Development Capital Expenditures	**$ 229.0**	$ 118.9
Average Benchmark Pricing		
AECO natural gas – monthly index (CDN$/Mcf)	**$ 3.58**	$ 4.24
AECO natural gas – daily index (CDN$/Mcf)	**$ 3.62**	$ 4.50
NYMEX natural gas – monthly NX3 index (US$/Mcf)	**$ 3.81**	$ 4.27
NYMEX natural gas – monthly NX3 index: CDN$ equivalent (CDN$/Mcf)	**$ 3.85**	$ 4.49
WTI crude oil (US$/bbl)	**$ 85.17**	$ 76.19
WTI crude oil: CDN$ equivalent (CDN$/bbl)	**$ 86.03**	$ 80.20
USD$/CDN$ exchange rate	**0.99**	0.95

(1) Calculated based on distributions paid or payable. Cash distributions to unitholders per unit may not correspond to actual distributions per trust unit as a result of using the annual weighted average trust units outstanding.
(2) Based on weighted average trust units outstanding.
(3) Payout ratio is calculated as cash distributions to unitholders divided by cash flow from operating activities. Adjusted payout ratio is calculated as the sum of cash distributions to unitholders plus development capital and office expenditures divided by cash flow from operating activities. See "Non-GAAP Measures" above.
(4) Non-cash amounts have been excluded.
(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

SELECTED QUARTERLY CANADIAN AND U.S. FINANCIAL RESULTS

(CDN$ millions, except per unit amounts)	Three months ended December 31, 2010			Three months ended December 31, 2009		
	Canada	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Average Daily Production Volumes						
Natural gas (Mcf/day)	**244,510**	**29,804**	**274,314**	291,833	13,858	305,691
Crude oil (bbls/day)	**18,930**	**11,438**	**30,368**	24,271	7,319	31,590
Natural gas liquids (bbls/day)	**4,027**	**–**	**4,027**	4,238	–	4,238
Total daily sales (BOE/day)	**63,709**	**16,405**	**80,114**	77,148	9,629	86,777
Pricing[(1)]						
Natural gas (per Mcf)	**$ 3.47**	**$ 4.94**	**$ 3.63**	$ 3.95	$ 6.20	$ 4.06
Crude oil (per bbl)	**$ 71.22**	**$ 73.78**	**$ 72.18**	$ 67.07	$ 70.66	$ 67.90
Natural gas liquids (per bbl)	**$ 53.66**	**$ –**	**$ 53.66**	$ 56.96	$ –	$ 56.96
Capital Expenditures						
Development capital and office	**$ 132.4**	**$ 98.6**	**$ 231.0**	$ 99.2	$ 22.4	$ 121.6
Acquisitions of oil and gas properties	**$ 5.9**	**$ 518.4**	**$ 524.3**	$ 2.3	$ 46.8	$ 49.1
Dispositions of oil and gas properties	**$ (537.9)**	**$ –**	**$ (537.9)**	$ (102.1)	$ –	$ (102.1)
Revenues						
Oil and gas sales[(1)]	**$ 222.0**	**$ 91.2**	**$ 313.2**	$ 277.7	$ 55.5	$ 333.2
Royalties[(2)]	**$ (23.8)**	**$ (21.9)**	**$ (45.7)**	$ (39.4)	$ (12.9)	$ (52.3)
Commodity derivative instruments gain/(loss)	**$ (46.1)**	**$ –**	**$ (46.1)**	$ 14.5	$ –	$ 14.5
Expenses						
Operating	**$ 53.8**	**$ 5.5**	**$ 59.3**	$ 70.5	$ 3.7	$ 74.2
General and administrative	**$ 21.2**	**$ 2.4**	**$ 23.6**	$ 25.5	$ 2.5	$ 28.0
Depletion, depreciation, amortization and accretion	**$ 123.9**	**$ 30.8**	**$ 154.7**	$ 148.8	$ 17.4	$ 166.2
Current income taxes (recovery)/expense	**$ 16.6**	**$ (13.6)**	**$ 3.0**	$ –	$ (5.3)	$ (5.3)

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

CRITICAL ACCOUNTING POLICIES

The financial statements have been prepared in accordance with Canadian GAAP. A summary of significant accounting policies is presented in Note 2. A reconciliation of differences between Canadian and United States GAAP is presented in Note 16. Most accounting policies are mandated under GAAP however, in accounting for oil and gas activities, we have a choice between the full cost and the successful efforts methods of accounting.

We apply the full cost method of accounting for oil and natural gas activities. Under the full cost method of accounting, all costs of acquiring, exploring and developing oil and natural gas properties are capitalized, including unsuccessful drilling costs and administrative costs associated with acquisitions and development. Under the successful efforts method of accounting, all exploration costs, except costs associated with drilling successful exploration wells, are expensed in the period in which they are incurred. The difference between these two methodologies is not expected to be significant to net income or net income per share.

Under the full cost method of accounting, an impairment test is applied to the overall carrying value of property, plant and equipment, on a country by country cost centre basis with the reserves valued using estimated future commodity prices at period end. Under the successful efforts method of accounting, the costs are aggregated on a property-by-property basis. The carrying value of each property is subject to an impairment test. Each method of accounting may generate a different carrying value of property, plant and equipment and a different net income depending on the circumstances at period end. Net costs related to operating and administrative activities during the development of large capital projects are capitalized until commercial production has commenced and are tested for impairment separately under full cost accounting.

CRITICAL ACCOUNTING ESTIMATES

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

Reserves

The process of estimating reserves is critical to several accounting estimates. It requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and gas prices, operating costs and royalty burdens change. Reserve estimates impact net income through depletion, the determination of asset retirement obligations and the application of an impairment test. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income and the asset retirement obligation.

Asset Retirement Obligation

Management calculates the asset retirement obligation based on estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and amortized over its useful life.

Business Combinations

Management makes various assumptions in determining the fair values of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we estimate (a) oil and gas reserves in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and (b) future prices of oil and gas.

Commodity Prices

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

Derivative Financial Instruments

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

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

Consolidated Financial Statements

Section 1601 "Consolidated Financial Statements" establishes the requirements for the preparation of consolidated financial statements and was effective January 1, 2011. This standard will not have a material impact on our consolidated financial statements.

Convergence of Canadian GAAP with International Financial Reporting Standards

Financial Reporting Update

As a publicly accountable enterprise we are required to apply IFRS, in full and without modification, for financial periods beginning on January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010. Our transition to IFRS continues to progress according to plan and we anticipate meeting our 2011 financial reporting requirements.

On adoption of IFRS certain financial statement adjustments are required to be made retroactively against our opening retained earnings (accumulated deficit) as at January 1, 2010. However, IFRS 1 – "First time adoption of international financial reporting standards" provides entities adopting IFRS certain optional exemptions to the general requirement for full retroactive application of IFRS. We expect to apply the following exemptions:

- Property, Plant and Equipment ("PP&E") – We will apply the exemption that allows companies that follow the Canadian GAAP full cost accounting guideline to allocate their historic net PP&E to Cash Generating Units ("CGU's") on the date of transition. We have allocated our PP&E into seven CGU's in Canada and one CGU in the United States, based on proved plus probable reserve values as at January 1, 2010.
- Business Combinations – IFRS 1 provides an optional exemption to the requirement to retroactively restate any past business combinations recorded under Canadian GAAP. We will apply 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 allows entities to set CTA to zero at the date of transition. We will apply this exemption and set CTA to zero at January 1, 2010 which will result in an increase to the accumulated deficit of approximately $82 million.
- Borrowing Costs – We will apply the IFRS 1 exemption which allows an entity to be exempt from capitalizing interest on qualifying assets where active development commenced before January 1, 2010. Our Kirby oil sands asset, which was sold in October 2010, would be considered a qualifying asset on January 1, 2010. As a result of the exemption no interest will be capitalized for Kirby.

A Canadian GAAP and IFRS reconciliation of our January 1, 2010 Balance Sheet and Equity is presented below. The adjustments and resulting IFRS amounts are unaudited and subject to change.

Reconciliation – Consolidated Opening Balance Sheet – January 1, 2010

(CDN$ thousands)	Note	IFRS January 1, 2010	Cdn GAAP December 31, 2009	Difference
Assets				
Current Assets				
Cash		**$ 73,558**	$ 73,558	$ –
Accounts Receivables		**142,009**	142,009	–
Deferred financial assets		**20,364**	20,364	–
Future income taxes	c	**–**	4,995	(4,995)
Other current		**5,041**	5,041	–
		240,972	245,967	(4,995)
Property, plant and equipment	a, b	**4,420,339**	5,000,523	(580,184)
Exploration and evaluation assets	a, b	**580,184**	–	580,184
Goodwill	a, b	**476,998**	607,438	(130,440)
Deferred financial assets		**1,997**	1,997	–
Other assets	g	**88,324**	49,591	38,733
		5,567,842	5,659,549	(91,707)
		$ 5,808,814	$ 5,905,516	$ (96,702)
Liabilities				
Current liabilities				
Accounts payable		**$ 257,519**	$ 257,519	$ –
Distributions payable to unitholders		**31,871**	31,871	–
Current portion of long-term debt		**36,631**	36,631	–
Deferred financial credits		**37,437**	37,437	–
		363,458	363,458	–
Long-term debt		**522,276**	522,276	–
Deferred financial credits		**54,788**	54,788	–
Deferred tax liability (FIT)	c	**588,329**	561,585	26,744
Decommissioning liability (ARO)	e	**385,885**	230,465	155,420
		1,551,278	1,369,114	182,164
Exchangeable limited partnership units	f	**55,816**	–	55,816
Trust unit rights incentive plan	f	**9,074**	–	9,074
		64,890	–	64,890
Equity				
Unitholders' capital		**5,580,558**	5,715,614	(135,056)
Accumulated deficit		**(1,751,370)**	(1,460,283)	(291,087)
Accumulated other comprehensive income/(loss)	d	**–**	(82,387)	82,387
		3,829,188	4,172,944	(343,756)
		$ 5,808,814	$ 5,905,516	$ (96,702)

Continuity of changes in equity

Unaudited (CDN$ '000s)	**Note**	**Unitholder's Capital**	**Accumulated other comprehensive income**	**Accumulated deficit**	**Total Equity**
Cdn GAAP Balance at December 31, 2009		$ 5,715,614	$ (82,387)	$ (1,460,283)	$ 4,172,944
IFRS Adjustments:					
Exchangeable limited partnership units	f	(112,709)		56,893	$ (55,816)
Trust unit rights incentive plan	f	(22,347)		13,273	(9,074)
Decommissioning liability (ARO) adjustment	e			(113,171)	(113,171)
Other assets	g			33,756	33,756
Goodwill impairment	a			(130,440)	(130,440)
Income taxes-dual rate	c			(69,011)	(69,011)
Cumulative translation adjustment exemption	d		82,387	(82,387)	–
IFRS Balance at January 1, 2010		**$ 5,580,558**	**$ –**	**$ (1,751,370)**	**$ 3,829,188**

Notes to the reconciliation from Canadian GAAP to IFRS

(a) Property, Plant and Equipment

Under IFRS capital costs will be 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 during 2010 however, as we continue to execute our strategy to obtain early stage growth assets we expect our Pre-E&E costs to increase.

ii. Exploration and Evaluation ("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 our 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. Management has identified approximately $580 million of assets that meet the criteria to be classified as E&E. The balance is comprised primarily of our Kirby oil sands asset, prior to its disposition on October 1, 2010, and undeveloped lands in Canada and the U.S.

iii. Developed and Producing ("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 CGU's, and recognized on the balance sheet separately from E&E assets.

As a result of the changes in accounting for PP&E under IFRS we expect a moderate decrease in the overall capitalization of our development capital and acquisition expenditures.

Depreciation and Depletion

Under Canadian GAAP depletion was calculated on a unit of production basis using proved reserves. Under IFRS we have a choice to deplete our D&P assets on a unit of production basis using either proved or proved plus probable reserves for each CGU. We expect to adopt a policy of depleting D&P assets using proved plus probable reserves for each CGU. As a result we expect our annual depletion rate to be reduced by approximately 3%, before the consideration of potential impairments.

Under IFRS an entity recognizes separate depreciable components where part of an asset is significant in value relative to the overall asset and it has a different useful life than the overall asset. We have assessed our assets and determined we do not have significant components.

Our office and other assets will continue to be depreciated on a straight-line basis over the assets' useful lives.

At January 1, 2010 our accumulated depletion was reset to zero in conjunction with the exemption that allowed companies to allocate their historic net PP&E to their CGUs. There is no change in our accumulated depreciation balances upon adoption of IFRS.

Derecognition of D&P assets

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

(b) Impairments

D&P assets

Under IFRS, testing for D&P asset impairments is completed at a CGU level compared to a country by country basis 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 fair value less cost to sell or value in use. 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 oil and gas assets.

As at January 1, 2010 no impairment existed on our D&P assets.

E&E assets

Under Canadian GAAP E&E assets were tested for impairment by comparing their recoverable amount to carrying value. Under IFRS E&E assets are subject to an assessment for impairment indicators at least annually and where indicators exist an impairment test is required. Our E&E asset impairment test compares the E&E assets' carrying value to the sum of the assets' fair value plus any excess of our D&P assets recoverable amount over their carrying value on a country by country basis.

As at January 1, 2010 there was no impairment on our E&E assets.

Goodwill

Under Canadian GAAP goodwill was carried on a consolidated basis. On transition to IFRS we allocated the goodwill generated from historic business combinations to the CGUs that benefited from the synergies of the combination.

Under Canadian GAAP the goodwill balance was assessed for impairment annually at year-end, or as indicators of impairment arose. Under IFRS goodwill is tested at least annually, in conjunction with our D&P asset impairment tests.

We expect to record a goodwill impairment of approximately $130.4 million in our shallow gas CGU at January 1, 2010 with an offset to accumulated deficit.

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.

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

(c) Deferred tax (previously future income taxes under Canadian GAAP)

Under IFRS all deferred taxes are required to be classified as long-term. As a result we have reclassified $5.0 million of future income taxes previously classified as current under Canadian GAAP to long term under IFRS.

Our income trust structure required us to apply a higher deferred tax rate to certain temporary differences under IFRS which resulted in an increase to our deferred tax liability of approximately $69.0 million at the date of transition. The majority of this increase will reverse on January 1, 2011, upon conversion to a corporation, with a corresponding credit to income.

A summary of the tax effect of other opening balance sheet adjustments at January 1, 2010 is as follows:

($ millions)	As at January 1, 2010
Higher deferred tax rate	$ 69.0
Decommissioning liability (ARO)	(42.3)
Other assets (Marketable securities)	5.0
Reclass-current tax asset to deferred liability	(5.0)
Net increase to deferred income tax liability	**$ 26.7**

(d) Foreign currency translation

Our U.S. operations are translated in the same manner under Canadian GAAP and IFRS. Assets and liabilities of these operations are translated into Canadian dollars at period end exchange rates, while revenue and expenses are converted using average rates for the period. Gains and losses from the translation into Canadian dollars are deferred and included in the cumulative translation adjustment ("CTA") which is part of accumulated other comprehensive income.

Upon adoption of IFRS we utilized an exemption that allowed us to reset the CTA balance to zero instead of retroactively restating it. As a result, at January 1, 2010 the CTA balance in other comprehensive income is zero.

(e) Decommissioning Liabilities (previously Asset Retirement Obligations under Canadian GAAP)

Under Canadian GAAP and IFRS we recognize a liability for the estimated fair value of the future retirement obligations associated with PP&E. Under Canadian GAAP the estimates of future cash outflows were discounted using a credit adjusted risk-free rate whereas IFRS recommends a risk-free rate. Additionally, accretion expense under IFRS is classified as a financing cost whereas it was included within DDA&A under Canadian GAAP.

At January 1, 2010 we recorded an increase to our ARO liability of approximately $155.4 million. In accordance with the IFRS 1 exemption for full cost oil and gas companies the offset of $113.1 million, net of $42.3 million in tax, was recorded to accumulated deficit.

(f) Enerplus Exchangeable limited partnership ("EELP") units and Trust Unit Rights

Pursuant to the Fund's trust indenture the Fund's trust units were redeemable at the option of the holder at 85% of the current trading price. Under Canadian GAAP the Fund's trust units and EELP units were considered permanent equity and included within unitholders' capital. Under IFRS the Fund's trust units are considered puttable financial instruments however a specific exemption for trust units specifies they are classified as permanent equity within unitholders' capital. 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.

On January 1, 2010 we recorded a $55.8 million liability representing the redemption value of our outstanding EELP units along with a $112.7 million reduction to our unitholder's capital and $56.9 million credit to our accumulated deficit to retroactively adjust for the impact of the EELP units.

We recorded a trust unit rights liability of $9.0 million on January 1, 2010, representing our trust unit rights fair value determined using a binomial lattice option pricing model on that date. In conjunction with the liability we reduced our contributed surplus by $22.3 million and recorded a credit of $13.3 million to our accumulated deficit.

(g) 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 we recorded an increase in other assets of approximately $39.0 million ($33.7 million net of tax) with the offset recorded against our accumulated deficit.

Other Considerations

Business Combinations

Under Canadian GAAP transaction costs on business combinations were capitalized. Under IFRS, such costs must be expensed. In addition, any equity purchase consideration under Canadian GAAP was measured based on the market price over a reasonable period around the announcement date. However, under IFRS equity consideration is measured based on the fair value on the date the consideration is transferred.

General and Administrative ("G&A") Expenses

Under IFRS we expect to capitalize fewer G&A expenses associated with acquisition and divestiture activities relative to Canadian GAAP. We expect this will increase our G&A expenses by approximately $0.20/BOE in 2011.

Operating cash flow

The transition to IFRS will impact our operating cash flow as IFRS requires certain costs be expensed that would have been previously capitalized under Canadian GAAP. These costs have been discussed throughout this section.

Other

In implementing the changes required for the transition to IFRS we have considered the following additional items:

- Internal controls over financial reporting ("ICFR") – We continue to review our ICFR documentation and are identifying instances where controls must be amended or added in order to address the accounting policy changes required under IFRS. No significant changes in control procedures are expected as a result of the transition to IFRS.
- Disclosure controls and procedures ("DC&P") – We have assessed the impact of transitioning to IFRS on our DC&P and have not identified any material changes required in our control environment although we do expect increased note disclosure. We have drafted IFRS note disclosure in accordance with current IFRS standards and continue to monitor requirements put forth by the International Accounting Standards Board in discussion papers and exposure drafts for future disclosure requirements.
- Business activities – We have been actively working with counterparties to ensure agreements that make reference to Canadian GAAP statements are modified to allow for IFRS. We do not anticipate any issues with our existing debt covenants and related agreements.
- Information systems – We implemented certain changes to our accounting systems in preparation for IFRS. The modifications were not significant but were required in order to allow for proper accounting and reporting of both Canadian GAAP and IFRS statements related to 2010.

RISK FACTORS AND RISK MANAGEMENT

Commodity Price Risk

Our operating results and financial condition are dependent on the prices we receive for our crude oil and natural gas production. These prices have fluctuated widely in response to a variety of factors including global and domestic demand, weather conditions, the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American natural gas, political stability, transportation facilities, the price and availability of alternative fuels and government regulations.

We may use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of natural gas and crude oil price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains unhedged. Furthermore, we may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase. Refer to the "Price Risk Management" section for further details on our price risk management program.

Oil and Gas Reserves and Resources Risk

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

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

McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 86% of the total proved plus probable value (discounted at 10%) of our Canadian conventional year-end reserves, 96% of our western U.S. assets and have reviewed the remainder of the reserves which we evaluated internally. In addition, McDaniel reviewed the evaluation of our contingent resources in the Bakken at Fort Berthold as prepared by Enerplus. Haas Petroleum Engineering Services, Inc. ("Haas") evaluated 100% of the reserves and contingent resources associated with our Marcellus shale gas property in the eastern United States.

To ensure comparability, all of the independent reserve engineering firms utilized McDaniel's forecast and constant price and cost assumptions as of December 31, 2010 and evaluated our reserves in accordance with NI 51-101.

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

Access to Capital Markets

Our access to capital has allowed us to fund a portion of our acquisitions and development capital program through equity and debt and as a result, distribute a significant portion of our cash flow to our unitholders. Continued access to capital is dependent on our ability to optimize our existing assets and to demonstrate the advantages of the acquisition or development program that we are financing at the time.

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

Marcellus Shale Gas

The Marcellus properties represent a shale gas asset outside of our traditional geographic areas. We have limited experience in the drilling and development of shale gas properties. The expansion of our activities into this new resource play may present challenges and risks that we have not faced in the past. Failure to manage risks successfully may adversely affect the results of our operations and financial condition.

We purchased a non-operated position in 2009 and initially relied upon our partner's expertise, Chief Oil & Gas LLC ("Chief"), with respect to ongoing development and operations in the Marcellus shale gas region. We monitor costs and results from capital programs adjusting them as we learn and evolve our development plans in the area. As well, in 2010 we acquired an operated interest in the Marcellus with the intention of applying our learnings to properties more directly in our control.

Access to Transportation Capacity

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

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

Access to Field Services

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

We have entered into service contracts for a portion of field services in our US Bakken play that will secure a drilling rig and fracturing services for two years commencing in early 2011. Access to field services and supplies in other areas of our business will continue to be subject to market availability.

Regulatory Risk & Greenhouse Gas Emissions

Government royalties, environmental laws and regulatory requirements can have a significant financial and operational impact on us. As an oil and gas producer, we are subject to a broad range of regulatory requirements that continue to increase both within Canada and the United States.

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

Specifically with respect to regulations for the reduction of greenhouse gas emissions, the Canadian federal government did not issue the expected regulations in 2009, but rather continues to seek alignment with the regulations to be issued with those of the United States. Accordingly, while we continue to prepare to meet the potential requirements, the actual cost impact and its materiality to our business remains uncertain.

Production Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Our ability to replace production depends on our success in acquiring new reserves and resources and developing existing reserves and resources. Acquisitions of oil and gas assets depend on our assessment of value at the time of acquisition.

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

Health, Safety and Environmental Risk (''HSE'')

Health, safety and environmental risks influence the workforce, operating costs and the establishment of regulatory standards. Enerplus has established a Safety and Social Responsibility (''S&SR'') team that develops standards and systems to manage health, safety, environment, regulatory compliance and stakeholder engagement for the organization.

These management systems include:

- *leadership obligations and setting goals and objectives*
- *training needs and competency standards*
- *measuring, reporting and analyzing performance*
- *developing critical standards, procedures and guidelines*
- *audits, inspections and compliance monitoring*
- *emergency response planning*
- *identify and manage environmental liabilities associated with our existing asset base and potential acquisitions*

- *integrity management programs for pipelines and facilities*

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

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

Counterparty and Joint Venture Credit Exposure

Early in 2009 economic conditions negatively affected the availability of credit and increased the credit risk associated with our oil and gas sales, financial derivatives and joint venture operations. Generally credit markets have improved however there remains a risk that our counterparties may experience financial problems. Furthermore, if natural gas prices remain low there is a risk of increased bad debts related to our joint venture industry partners.

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

See the "Liquidity and Capital Resources" section for further information.

Foreign Currency Exposure

We have exposure to fluctuations in foreign currency as most of our senior unsecured notes are denominated in U.S. dollars. Our U.S. operations are directly exposed to fluctuations in the U.S. dollar when translated to our Canadian dollar denominated financial statements.

We also have indirect exposure to fluctuations in foreign currency as our crude oil sales and a portion of our natural gas sales are based on U.S. dollar indices. Our oil and gas revenues are positively impacted as the Canadian dollar weakens relative to the U.S. dollar.

We have hedged our foreign currency exposure on both our US$175 million and US$54 million senior unsecured notes using financial swaps that convert the U.S. denominated debt to Canadian dollar debt. In addition we have hedged the U.S. dollar interest obligation on our US$175 million notes. We have not entered into any other foreign currency derivatives with respect to our oil and gas sales, our U.S. operations or the U.S. senior unsecured notes issued during 2009.

Interest Rate Exposure

We have exposure to movements in interest rates and credit markets as changing interest rates affect our borrowing costs and the unit price of yield-based investments such as our trust units as well as other equity investments.

We monitor the interest rate forward market and have fixed the interest rate on approximately 59% of our debt through our senior unsecured notes and interest rate swaps.

Changes in Tax and Other Laws

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

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

2011 GUIDANCE

A summary of our 2011 guidance is below which does not include any potential acquisitions or divestments:

Summary of 2011 Expectations	Target	Comments
Average annual production	78,000 - 80,000 BOE/day	
Exit rate 2011 production	80,000 - 84,000 BOE/day	Assumes $650 million development capital spending
2011 production mix	53% gas, 47% liquids	
Average royalty rate	20%	Percentage of gross sales (net of transportation costs)
Operating costs	$9.20/BOE	
G&A costs	$3.30/BOE	Includes non-cash charges of $0.30/BOE (stock option plan) and $0.20/BOE impact of the new IFRS rules
Average interest and financing costs	6%	Based on current fixed rate contracts and forward interest rates
Development capital spending	$650 million	Within the context of current commodity prices
Marcellus carry commitment spending	$116 million	Will be reported as a property acquisition

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at December 31, 2010, our disclosure controls and procedures and internal control over financial reporting are effective. There were no changes in our internal control over financial reporting during the period beginning on October 1, 2010 and ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to Enerplus Resources Fund and its successor issuer, Enerplus Corporation, 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 information 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: our corporate strategy, including our transition from an income trust to a corporation; our strategy to deliver both income and growth to investors and our related asset portfolio; future returns to our shareholders from both dividends and from growth in per share production and reserves; expected oil, natural gas and natural gas liquids production volumes and product mix; future oil and natural gas prices and our commodity risk management programs; cash flow sensitivities to commodity price, production, foreign exchange and interest rate changes; expected royalty rates and operating, G&A and interest expenses; development capital expenditures and the allocation thereof among our assets and resource plays; the amount of future abandonment and reclamation costs and asset retirement obligations; future income taxes, our tax pools and the time at which we may pay cash taxes; future debt and debt-to-cash-flow levels, financial capacity, liquidity and capital resources to fund development capital spending and working capital requirements; potential asset dispositions; our credit risk mitigation programs; the amount and timing of future cash dividends that we may pay to our shareholders; future contractual commitments; our transition to IFRS and the impact of that change on our financial results and disclosure; and future environmental obligations and the costs associated therewith.*

The forward-looking information contained in this MD&A reflects several material factors and 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 cash flow to fund our capital and operating requirements as needed; 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 are not guarantees 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 development activities or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our development 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 certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in this MD&A and under "Risk Factors" in the Annual Information Form of Enerplus Resources Fund (the "Fund") dated March 12, 2010, which is available on our website at www.enerplus.com and on the Fund's SEDAR profile at www.sedar.com and which forms part of the Fund's Form 40-F filed with the SEC on March 12, 2010 and which is available at www.sec.gov. Additional risk factors will be contained in our Annual Information Form (and corresponding Form 40-F) for the year ended December 31, 2010, which will be filed in mid-March 2011.

The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2010, our internal control over financial reporting is effective.

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

The effectiveness of the Fund's internal control over financial reporting as of December 31, 2010, has been audited by Deloitte & Touche LLP, the Fund's Independent Registered Chartered Accountants, who also audited the Fund's Consolidated Financial Statements for the year ended December 31, 2010.

Gordon J. Kerr
President and
Chief Executive Officer

Robert J. Waters
Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 24, 2011

Report of Independent Registered Chartered Accountants

To the Board of Directors and Shareholders of Enerplus Corporation

We have audited the internal control over financial reporting of Enerplus Resources Fund and subsidiaries (the "Fund") as of December 31, 2010, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Fund's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Fund's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Fund maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as at and for the year ended December 31, 2010 of the Fund and our report dated February 24, 2011 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

Independent Registered Chartered Accountants

Calgary, Canada
February 24, 2011

Management's Responsibility for Financial Statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Resources Fund (the "Fund") have been prepared within reasonable limits of materiality and in accordance with Canadian generally accepted accounting principles. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 24, 2011. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

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

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

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

Gordon J. Kerr
President and
Chief Executive Officer

Robert J. Waters
Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 24, 2011

Report of Independent Registered Chartered Accountants

To the Board of Directors and Shareholders of Enerplus Corporation

We have audited the accompanying consolidated financial statements of Enerplus Resources Fund and subsidiaries (the "Fund"), which comprise the consolidated balance sheets as at December 31, 2010 and 2009, and the consolidated statements of income, comprehensive income (loss), accumulated deficit and accumulated other comprehensive income (loss) and cash flows for the years then ended, and the notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

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

Auditor's Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enerplus Resources Fund and subsidiaries as at December 31, 2010 and 2009 and the results of their operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Fund's internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2011 expressed an unqualified opinion on the Fund's internal control over financial reporting.

Deloitte & Touche LLP

Independent Registered Chartered Accountants

Calgary, Canada
February 24, 2011

Consolidated Balance Sheets

As at December 31 (CDN$ thousands)	2010	2009
Assets		
Current assets		
Cash	**$ 8,374**	$ 73,558
Accounts receivable	**125,928**	142,009
Deferred financial assets *(Note 13)*	**12,641**	20,364
Future income taxes *(Note 12)*	**10,782**	4,995
Other current *(Note 4)*	**49,606**	5,041
	207,331	245,967
Property, plant and equipment *(Note 5)*	**4,976,885**	5,000,523
Goodwill *(Note 2(e))*	**599,672**	607,438
Deferred financial assets *(Note 13)*	**385**	1,997
Other assets *(Note 13)*	**50,899**	49,591
	5,627,841	5,659,549
	$ 5,835,172	$ 5,905,516
Liabilities		
Current liabilities		
Accounts payable	**$ 350,623**	$ 257,519
Distributions payable to unitholders	**32,157**	31,871
Current portion of long-term debt *(Note 8)*	**–**	36,631
Deferred financial credits *(Note 13)*	**56,637**	37,437
	439,417	363,458
Long-term debt *(Note 8)*	**732,405**	522,276
Deferred financial credits *(Note 13)*	**46,943**	54,788
Future income taxes *(Note 12)*	**502,584**	561,585
Asset retirement obligations *(Note 7)*	**208,704**	230,465
	1,490,636	1,369,114
Equity		
Unitholders' capital *(Note 11)*		
Trust Units and Trust Units Equivalent		
Authorized: Unlimited		
Issued and Outstanding: 2010 – 178,648,351		
2009 – 177,061,253	**5,756,976**	5,715,614
Accumulated deficit	**(1,717,299)**	(1,460,283)
Accumulated other comprehensive income/(loss)	**(134,558)**	(82,387)
	3,905,119	4,172,944
	$ 5,835,172	$ 5,905,516

See accompanying notes to the Consolidated Financial Statements

Signed on behalf of the Board of Directors:

Douglas R. Martin
Director

Robert B. Hodgins
Director

Consolidated Statements of Accumulated Deficit and Accumulated Other Comprehensive Income (Loss)

For the year ended December 31 (CDN$ thousands)	2010	2009
Accumulated income, beginning of year	**$ 3,264,936**	$ 3,175,819
Net income	**127,112**	89,117
Accumulated income, end of year	**3,392,048**	3,264,936
Accumulated cash distributions, beginning of year	**(4,725,219)**	(4,357,018)
Cash distributions	**(384,128)**	(368,201)
Accumulated cash distributions, end of year	**(5,109,347)**	(4,725,219)
Accumulated deficit, end of year	**$ (1,717,299)**	$ (1,460,283)
Accumulated other comprehensive income/(loss), beginning of year	**$ (82,387)**	$ 48,606
Other comprehensive income/(loss)	**(52,171)**	(130,993)
Accumulated other comprehensive income/(loss), end of year	**$ (134,558)**	$ (82,387)
Total accumulated deficit and other comprehensive income/(loss)	**$ (1,851,857)**	$ (1,542,670)

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Income

For the year ended December 31 (CDN$ thousands)	2010	2009
Revenues		
Oil and gas sales	**$ 1,327,140**	$ 1,259,146
Royalties	**(223,459)**	(207,491)
Commodity derivative instruments *(Note 13)*	**23,996**	34,893
Other income/(loss)	**779**	(1,478)
	1,128,456	1,085,070
Expenses		
Operating	**289,537**	327,211
General and administrative	**78,928**	88,293
Transportation	**26,959**	26,383
Interest *(Note 9)*	**46,736**	56,257
Foreign exchange *(Note 10)*	**(931)**	(59,579)
Depletion, depreciation, amortization and accretion	**645,294**	650,381
	1,086,523	1,088,946
Income/(loss) before taxes	**41,933**	(3,876)
Current tax expense/(recovery) *(Note 12)*	**(30,375)**	198
Future income tax recovery *(Note 12)*	**(54,804)**	(93,191)
Net Income	**$ 127,112**	$ 89,117
Net income per trust unit		
Basic	**$ 0.72**	$ 0.53
Diluted	**$ 0.71**	$ 0.53
Weighted average number of trust units outstanding (thousands) *(Note 11)*		
Basic	**177,737**	169,280
Diluted	**178,090**	169,549

Consolidated Statements of Comprehensive Income (Loss)

For the year ended December 31 (CDN$ thousands)	2010	2009
Net income	**$ 127,112**	$ 89,117
Other comprehensive income/(loss), net of tax:		
Unrealized gain on marketable securities *(Note 13)*	**251**	–
Change in cumulative translation adjustment	**(52,422)**	(130,993)
Other comprehensive income/(loss)	**(52,171)**	(130,993)
Comprehensive income/(loss)	**$ 74,941**	$ (41,876)

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

For the year ended December 31 (CDN$ thousands)	2010	2009
Operating Activities		
Net income	**$ 127,112**	$ 89,117
Non-cash items add/(deduct):		
Depletion, depreciation, amortization and accretion	**645,294**	650,381
Change in fair value of derivative instruments *(Note 13)*	**20,690**	171,610
Unit based compensation *(Note 11 (d))*	**5,944**	6,542
Foreign exchange on U.S. dollar denominated debt *(Note 10)*	**(25,549)**	(62,524)
Future income tax *(Note 12)*	**(54,804)**	(93,191)
Amortization of senior notes premium *(Note 9)*	**(645)**	(758)
Loss/(gain) on sale of marketable securities *(Note 13)*	**–**	2,191
Cross currency interest rate swap principal settlement	**17,969**	–
Asset retirement obligations settled *(Note 7)*	**(17,240)**	(13,802)
	718,771	749,566
Decrease/(Increase) in non-cash operating working capital	**(15,623)**	26,220
Cash flow from operating activities	**703,148**	775,786
Financing Activities		
Issue of trust units, net of issue costs *(Note 11)*	**35,418**	237,736
Cash distributions to unitholders	**(384,128)**	(368,201)
Increase/(Decrease) in bank credit facilities *(Note 8)*	**235,388**	(380,888)
Issuance/(Repayment) of senior unsecured notes	**(35,697)**	338,735
Cross currency interest rate swap principal settlement	**(17,969)**	–
Decrease/(Increase) in non-cash financing working capital	**287**	(9,526)
Cash flow from financing activities	**(166,701)**	(182,144)
Investing Activities		
Capital expenditures	**(546,682)**	(305,865)
Property and land acquisitions *(Note 6)*	**(1,018,069)**	(271,977)
Property dispositions *(Note 6)*	**871,458**	104,325
Proceeds on sale of marketable securities	**–**	4,434
Purchase of marketable securities	**(1,016)**	(9,100)
Decrease/(Increase) in non-cash investing working capital	**92,870**	(45,482)
Cash flow from investing activities	**(601,439)**	(523,665)
Effect of exchange rate changes on cash	**(192)**	(3,341)
Change in cash	**(65,184)**	66,636
Cash, beginning of year	**73,558**	6,922
Cash, end of year	**$ 8,374**	$ 73,558
Supplementary Cash Flow Information		
Cash income taxes (received)/paid	**$ (6,529)**	$ (27,387)
Cash interest paid	**$ 46,565**	$ 29,582

See accompanying notes to the Consolidated Financial Statements

Notes to Consolidated Financial Statements

1. ORGANIZATION AND BASIS OF ACCOUNTING

These financial statements and notes present the results of Enerplus Resources Fund, the predecessor to Enerplus Corporation. 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"). The directors and management of Enerplus remain the same as immediately prior to the conversion and the Company continues 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 in 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 have been cancelled and the Fund and EELP have been dissolved.

Enerplus' financial statements include the accounts of the Company and its subsidiaries on a consolidated basis. All inter-entity transactions have been eliminated. Many of Enerplus' production activities are conducted through joint ventures and the financial statements reflect only the Company's proportionate interest in such activities.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The management of Enerplus prepare the consolidated financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). A reconciliation between Canadian GAAP and United States of America GAAP ("U.S. GAAP") is disclosed in Note 16. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimated. In particular, the amounts recorded for depletion and depreciation of the petroleum and natural gas properties and for asset retirement obligations 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.

The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Revenue Recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from Enerplus to its customers based on price, volumes delivered and contractual delivery points. A portion of the properties acquired through the March 5, 2003 acquisition of PCC Energy Inc. and PCC Energy Corp. are subject to a royalty arrangement with a private company, that is structured as a net profits interest. The results from operations included in Enerplus' consolidated financial statements for these properties are reduced for this net profits interest.

(b) Property, Plant and Equipment ("PP&E")

Enerplus follows the full cost method of accounting for petroleum and natural gas properties under which all acquisition and development costs are capitalized on a country by country cost centre basis. Such costs include land acquisition, geological, geophysical, drilling costs for productive and non-productive wells, facilities and directly related overhead charges. Repairs, maintenance and operational costs that do not extend or enhance the recoverable reserves are charged to earnings. Proceeds from the sale of petroleum and natural gas properties are applied against the capitalized costs. Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20% or more. Net costs related to operating and administrative activities during the development of large capital projects are capitalized until commercial production has commenced.

(c) Impairment Test

A limit is placed on the aggregate carrying value of PP&E (the "impairment test"). Enerplus performs an impairment test on a country by country basis. An impairment loss exists when the carrying amount of the country's PP&E exceeds the estimated undiscounted future net cash flows associated with the country's proved reserves. If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the country's proved and probable reserves are charged to income. Net costs related to projects in the pre-commercial phase of development are excluded from the country by country impairment test and are tested for impairment separately.

(d) Depletion and Depreciation

The provision for depletion and depreciation of oil and natural gas assets is calculated on a country by country basis using the unit-of-production method, based on the country's share of estimated proved reserves before royalties. Reserves and production are converted to equivalent units on the basis of 6 Mcf = 1 bbl, reflecting the approximate relative energy content.

(e) Goodwill

Enerplus, when appropriate, 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 foreign operations fluctuates due to changes in foreign exchange rates. The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. To assess impairment, the fair values of the Canadian and U.S. reporting units are compared to their respective book values. If the fair value is less than the book value, a second test is performed to determine the amount of impairment. The amount of impairment is measured by allocating the fair value of the reporting unit to its identifiable assets and liabilities as if they had been acquired in a business combination for a purchase price equal to their fair value. If goodwill determined in this manner is less than the carrying value of goodwill, an impairment is recognized in the period in which it occurs. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

(f) Asset Retirement Obligations

Enerplus recognizes a liability for the estimated fair value of the future retirement obligations associated with its PP&E. The fair value is capitalized and amortized over the same period as the underlying asset. Enerplus estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. This estimate is evaluated on a periodic basis and any adjustment to the estimate is prospectively applied. As time passes, the change in net present value of the future retirement obligation is expensed through accretion. Retirement obligations settled during the period reduce the future retirement liability. No gains or losses on retirement activities were realized due to settlements approximating the estimates.

(g) Income Taxes

In 2010 Enerplus was a taxable entity under the Income Tax Act (Canada) and was taxable only on Canadian income that was not distributed or distributable to Enerplus' unitholders. In the trust structure, payments made between the Canadian operating entities and the Fund ultimately transferred both income and future income tax liability to the unitholders. The future income tax liability associated with Canadian assets recorded on the balance sheet was recovered over time through these payments.

Effective January 1, 2011, as a result of the conversion of the Fund to a corporation, the Company and its Canadian entities will be subject to the Canadian corporate income tax rate. The future tax liability associated with Canadian assets recorded on the balance sheet at December 31, 2010 reflects the underlying income tax rates of a corporation going forward.

Enerplus' U.S. operating subsidiary is subject to U.S. income taxes on its taxable income determined under U.S. income tax rules and regulations. Repatriation of funds from U.S. operations will also be subject to applicable withholding taxes as required under U.S. tax law.

Enerplus follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to the temporary differences between the carrying value of the assets and liabilities on the consolidated financial statements and their respective tax bases, using substantively enacted income tax rates. The effect of a change in these income tax rates on future income tax liabilities and assets is recognized in income during the period that the change occurs.

The determination of the income tax provision is inherently complex and interpretations will vary. Professional judgment is required for complex tax issues. The Company's income tax filings are subject to audits and re-assessments. Management believes that the provision for income taxes has appropriately provided for all income tax obligations. However, changes in facts, circumstances and interpretations may result in an increase or decrease in the Company's provision for income taxes.

(h) Financial Instruments

Enerplus is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by the Company to reduce its exposure to these risks. Enerplus records its derivative instruments on the Consolidated Balance Sheet at fair value and recognizes any change in fair value through net income during the period. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be received or paid to settle these instruments at the balance sheet date.

The Company has certain minor equity investments in entities involved in the oil and gas industry. Investments that have a quoted price in an active market are measured at fair value with changes in fair value recognized in other comprehensive income. When the investment is 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. Investments that do not have a quoted price in an active market are measured at cost unless there has been any other than temporary impairment, in which case a charge is recognized in net income to record the loss in value.

(i) Foreign Currency Translation

Enerplus' U.S. operations are self-sustaining. Assets and liabilities of these operations are translated into Canadian dollars at period end exchange rates, while revenues and expenses are converted using average rates for the period. Gains and losses from the translation into Canadian dollars are deferred and included in the cumulative translation adjustment ("CTA") which is part of accumulated other comprehensive income ("AOCI").

Revenues and expenses denominated in a foreign currency are translated at rates of exchange at the respective transaction dates. Monetary assets and liabilities denominated in a foreign currency are translated at rates of exchange in effect at the balance sheet date. Translation gains or losses are included in net income in the period in which they arise.

(j) Unit Based Compensation

Enerplus uses the fair value method of accounting for its trust unit rights incentive plan. Under this method, the fair value of the rights is determined on the date in which fair value can reasonably be determined, generally being the grant date. This amount is charged to earnings over the vesting period of the rights, with a corresponding increase in contributed surplus. When rights are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to unitholders' capital.

3. CHANGES IN ACCOUNTING POLICIES

Future Accounting Changes

Convergence of Canadian GAAP with International Financial Reporting Standards ("IFRS")

In 2006, Canada's Accounting Standards Board (AcSB) ratified a strategic plan to converge Canadian GAAP with IFRS by 2011 for public reporting entities. On February 13, 2008 the AcSB confirmed that IFRS would replace Canadian GAAP for public companies beginning January 1, 2011. The Company intends to issue financial statements under IFRS for periods beginning on or after January 1, 2011.

4. OTHER CURRENT ASSETS

Included in Other Current Assets at December 31, 2010 is a current income tax receivable of $45,900,000 (December 31, 2009 – $nil) relating to the recovery of income taxes paid in prior years by the Company's U.S. subsidiary.

5. PROPERTY, PLANT AND EQUIPMENT ("PP&E")

($ thousands)	2010	2009
Property, plant and equipment	**$ 9,411,838**	$ 8,827,191
Accumulated depletion, depreciation and accretion	**(4,434,953)**	(3,826,668)
Net property, plant and equipment	**$ 4,976,885**	$ 5,000,523

Capitalized general and administrative ("G&A") expenses for 2010 of $19,986,000 (2009 – $21,543,000) are included in PP&E. The depletion and depreciation calculation includes future capital costs of $654,064,000 (2009 – $661,175,000) as indicated in Enerplus' reserve reports. Excluded from PP&E for the depletion and depreciation calculation is $1,204,220,000 (2009 – $462,989,000) related to undeveloped land and oil sands projects which have not yet commenced commercial production.

An impairment test calculation was performed on a country by country basis on the PP&E values at December 31, 2010 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Company's PP&E.

The following table outlines estimated benchmark prices and the exchange rate used in the impairment tests for both Canadian and U.S. cost centers at December 31, 2010:

Year	WTI Crude Oil(1) US$/bbl	Exchange Rate US$/CDN$	Edm Light Crude(1) CDN$/bbl	U.S. Henry Hub Gas price(1) US$/Mcf	Natural Gas 30 day spot @ AECO(1) CDN$/Mcf
2011	$ 85.00	$ 0.975	$ 84.20	$ 4.55	$ 4.25
2012	87.70	0.975	88.40	5.30	4.90
2013	90.50	0.975	91.80	5.75	5.40
2014	93.40	0.975	94.80	6.30	5.90
2015	96.30	0.975	97.70	6.80	6.35
Thereafter*	+2% yr	0.975	+2% yr	+2% yr	+2% yr

(1) Prices used in the impairment test were adjusted for commodity price differentials specific to Enerplus.
* Escalation varies after 2015.

6. PROPERTY ACQUISITIONS AND DISPOSITIONS

On October 15, 2010, Enerplus acquired an additional 46,500 net acres of land in the Fort Berthold area for consideration of $468,704,000 before closing adjustments.

On September 1, 2009 Enerplus acquired a non-operated interest in the Marcellus shale natural gas formation. Consideration of $181,342,000 in cash was paid upon closing. In addition, up to $272,033,000 may be paid as a carry of 50% of our partners' future drilling and completion costs. During 2010, Enerplus satisfied $92,347,000 of the carry commitment and the remaining commitment at December 31, 2010 was $146,241,000 (US$147,032,000).

On October 1, 2010, Enerplus disposed of its 100% working interest in the Kirby oil sands lease for proceeds of $404,800,000. During 2010 Enerplus also completed the disposition of conventional non-core properties for proceeds of $465,200,000 net of closing adjustments.

7. ASSET RETIREMENT OBLIGATIONS

Total future asset retirement obligations were estimated by management for Enerplus' assets based on its net ownership interest, estimated abandonment and reclamation costs and the estimated timing of the costs to be incurred in future periods. Enerplus has estimated the net present value of its total asset retirement obligations to be $208,704,000 at December 31, 2010 compared to $230,465,000 at December 31, 2009, based on a total undiscounted liability of $590,177,000 and $676,823,000 respectively. These payments are expected to be made over the next 66 years with the majority of costs incurred between 2031 and 2050. To calculate the present value of the asset retirement obligations for 2010, Enerplus used a weighted credit-adjusted rate of approximately 6.4% and an inflation rate of 2.0%, (2009 – 6.4% and 2.0%). Settlements during 2010 and 2009 approximated estimates and as a result no gains or losses were recognized.

The following is a reconciliation of the asset retirement obligations:

($ thousands)	2010	2009
Asset retirement obligations, beginning of year	**$ 230,465**	$ 207,420
Changes in estimates	**13,267**	20,140
Property acquisition and development activity	**2,825**	4,420
Dispositions	**(34,746)**	(553)
Asset retirement obligations settled	**(17,240)**	(13,802)
Accretion expense	**14,133**	12,840
Asset retirement obligations, end of year	**$ 208,704**	$ 230,465

8. DEBT

($ thousands)	December 31, 2010	December 31, 2009
Current portion of long-term debt*	**$ –**	$ 36,631
Long-term:		
Bank credit facility	**234,713**	–
Senior notes:		
CDN$40 million (Issued June 18, 2009)	**40,000**	40,000
US$40 million (Issued June 18, 2009)	**39,784**	41,864
US$225 million (Issued June 18, 2009)	**223,785**	235,485
US$54 million (Issued October 1, 2003)*	**53,709**	56,516
US$175 million (Issued June 19, 2002)*	**140,414**	148,411
	732,405	522,276
Total debt	**$ 732,405**	$ 558,907

* Principal repayments due in 2011 under these notes have not been included in current liabilities as Enerplus intends to refinance the amounts with its long-term bank credit facility.

Bank Credit Facility

During the second quarter of 2010 Enerplus renewed its unsecured, covenant-based bank credit facility for a three year term, maturing June 30, 2013. The facility size was reduced from $1.4 billion to $1.0 billion. Drawn fees range between 200 and 375 basis points over bankers' acceptance rates, with current borrowing costs of 200 basis points. Standby fees on the undrawn portion of the facility are based on 25% of the drawn pricing. The Company has the ability to request an extension of the facility each year or repay the entire balance at the end of the term. At December 31, 2010 Enerplus had $234.7 million drawn and was in compliance with all covenants under the facility. A fee of $5.0 million was paid to extend the facility for three years and was recorded in interest expense. The weighted average interest rate on the facility for the year ended December 31, 2010 was 2.3% (December 31, 2009 – 1.1%)

Senior Notes

On June 19, 2010 Enerplus settled its first principal payment on the US$175 million senior notes and associated cross currency interest rate swap principal settlement for a total of $53,700,000. The terms and rates of the Company's outstanding senior unsecured notes are detailed below:

Issue Date	Original Principal ($ thousands)	Remaining Principal ($ thousands)	Coupon Rate	Interest Payment Dates	Maturity Date	Term
June 18, 2009	CDN$40,000	CDN$40,000	6.37%	June 18 and December 18	June 18, 2015	Bullet payment on maturity
June 18, 2009	US$40,000	US$40,000	6.82%	June 18 and December 18	June 18, 2015	Bullet payment on maturity
June 18, 2009	US$225,000	US$225,000	7.97%	June 18 and December 18	June 18, 2021	Principal payments required in 5 equal annual installments beginning June 18, 2017
October 1, 2003	US$54,000	US$54,000	5.46%	April 1 and October 1	October 1, 2015	Principal payments required in 5 equal annual installments beginning October 1, 2011
June 19, 2002	US$175,000	US$140,000	6.62%	June 19 and December 19	June 19, 2014	Principal payments required in 4 equal annual installments from June 19, 2011

9. INTEREST EXPENSE

($ thousands)	2010	2009
Realized		
Interest on long-term debt	**$ 47,029**	$ 30,544
Unrealized		
(Gain)/loss on cross currency interest rate swap	**2,776**	30,458
(Gain)/loss on interest rate swaps	**(2,424)**	(3,987)
Amortization of the premium on senior unsecured notes	**(645)**	(758)
Interest Expense	**$ 46,736**	$ 56,257

10. FOREIGN EXCHANGE

($ thousands)	2010	2009
Realized		
Foreign exchange (gain)/loss	**$ 28,023**	$ (18,452)
Unrealized		
Foreign exchange (gain)/loss on U.S. dollar denominated debt	**(25,549)**	(62,524)
Foreign exchange (gain)/loss on cross currency interest rate swap	**(5,017)**	16,537
Foreign exchange (gain)/loss on foreign exchange swaps	**1,612**	4,860
Foreign exchange (gain)/loss	**$ (931)**	$ (59,579)

11. UNITHOLDERS' CAPITAL

Unitholders' capital as presented on the Consolidated Balance Sheets consists of trust unit capital, exchangeable partnership unit capital and contributed surplus.

Effective January 1, 2011, according to the Plan of Arrangement, shareholders 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.

($ thousands)	2010	2009
Trust units	**$ 5,658,549**	$ 5,580,933
Exchangeable partnership units	**68,137**	108,539
Contributed surplus	**30,290**	26,142
Balance, end of year	**$ 5,756,976**	$ 5,715,614

(a) Trust Units

Authorized: Unlimited number of trust units

(thousands)	2010		2009	
Issued:	**Units**	**Amount**	**Units**	**Amount**
Balance, beginning of year	**174,349**	**$ 5,580,933**	162,514	$ 5,328,629
Issued for cash:				
Pursuant to public offerings	**–**	**–**	10,406	213,531
DRIP*, net of redemptions	**1,212**	**28,780**	1,061	24,120
Pursuant to rights incentive plan	**375**	**6,638**	4	85
Non-cash:				
Exchangeable partnership units exchanged	**1,009**	**40,402**	364	14,568
Trust unit rights incentive plan	**–**	**1,796**	–	–
	176,945	**5,658,549**	174,349	5,580,933
Equivalent exchangeable partnership units	**1,703**	**68,137**	2,712	108,539
Balance, end of year	**178,648**	**$ 5,726,686**	177,061	$ 5,689,472

* The Distribution Reinvestment and Unit Purchase Plan.

In conjunction with the corporate conversion on January 1, 2011, Enerplus' monthly distribution reinvestment plan was converted to a monthly dividend reinvestment plan ("DRIP"). Canadian shareholders are entitled to reinvest cash dividends in additional common shares of Enerplus. Shares are issued at 95% of the weighted average market price on the Toronto Stock Exchange for the 10 trading days preceding a dividend payment date without service charges or brokerage fees.

(b) Exchangeable Partnership Units of EELP

During the year, 2,375,000 exchangeable partnership units were converted into 1,009,000 trust units. As at December 31, 2010, the 4,007,000 outstanding exchangeable partnership units represented the equivalent of 1,703,000 trust units.

(thousands)	2010		2009	
Issued:	**Units**	**Amount**	**Units**	**Amount**
Balance, beginning of year	**6,382**	**$ 108,539**	7,238	$ 123,107
Exchanged for trust units	**(2,375)**	**(40,402)**	(856)	(14,568)
Balance, end of period	**4,007**	**$ 68,137**	6,382	$ 108,539

Prior to January 1, 2011, EELP units were convertible at any time into trust units at the option of the holder at a ratio of 0.425 of an Enerplus trust unit for each partnership unit. The EELP unitholder also received cash distributions and had voting rights in accordance with the 0.425 exchange ratio.

(c) Contributed Surplus

($ thousands)	2010	2009
Balance, beginning of year	**$ 26,142**	$ 19,600
Trust unit rights incentive plan (non-cash) – exercised	**(1,796)**	–
Trust unit rights incentive plan (non-cash) – expensed	**5,944**	6,542
Balance, end of year	**$ 30,290**	$ 26,142

(d) Trust Unit Rights Incentive Plan

As at December 31, 2010 a total of 5,457,000 rights were issued and outstanding pursuant to the Trust Unit Rights Incentive Plan ("Rights Incentive Plan") with an average exercise price of $32.11. This represents 3.1% of the total trust units outstanding, of which 2,565,000 rights, with an average price of $42.27, were exercisable. Under the Rights Incentive Plan, distributions per trust unit to unitholders in a calendar quarter which represent a return of more than 2.5% of the net PP&E of Enerplus at the end of such calendar quarter may result in a reduction in the exercise price of the rights. There were no exercise price reductions during 2010.

Enerplus uses a binomial lattice option-pricing model to calculate the estimated fair value of rights granted under the plan. The following assumptions were used to arrive at the estimate of fair value:

	2010	2009
Dividend yield	**9.16%**	12.54%
Volatility	**44.12%**	44.43%
Risk-free interest rate	**2.57%**	1.70%
Forfeiture rate	**12.50%**	12.40%
Expected life	**3.4 years**	3.9 years
Right's exercise price reduction	**$ 1.24**	$ 1.92

The fair value of the rights granted during 2010 ranged between 16% and 17% of the underlying market price of a trust unit on the grant date. The weighted average grant-date fair value of options granted during the year was $4.04.

During the year Enerplus recorded $5,944,000 or $0.03 per unit (2009 – $6,542,000 or $0.04 per unit) of unit based compensation expense. The remaining fair value of the rights of $5,156,000 at December 31, 2010 (2009 – $4,782,000) will be recognized in earnings over the remaining vesting period of the rights. Activity for the rights issued pursuant to the Rights Incentive Plan is as follows:

	2010		2009	
	Number of Rights (000's)	Weighted Average Exercise Price[(1)]	Number of Rights (000's)	Weighted Average Exercise Price[(1)]
Trust unit rights outstanding				
Beginning of year	**5,250**	**$ 34.84**	4,001	$ 45.05
Granted	**1,749**	**23.60**	2,001	17.28
Exercised	**(375)**	**17.50**	(4)	22.40
Forfeited and expired	**(1,167)**	**36.28**	(748)	38.61
End of year	**5,457**	**$ 32.11**	5,250	$ 34.84
Rights exercisable at the end of the year	**2,565**	**$ 42.27**	2,393	$ 46.03

(1) Exercise price reflects grant prices less reduction in strike price discussed above.

The following table summarizes information with respect to outstanding rights as at December 31, 2010. Rights vest between one and three years and expire between four and six years.

Rights Outstanding at December 31, 2010 (000's)	Original Exercise Price	Exercise Price after Price Reductions	Expiry Date December 31	Rights Exercisable at December 31, 2010 (000's)
1	$ 40.70	$ 31.90	2011	1
5	37.25	28.82	2011	5
11	38.83	30.80	2011	11
88	40.80	33.12	2011	88
26	45.55	38.19	2011	26
40	44.86	37.85	2011	40
34	49.75	43.14	2011	34
230	56.93	50.73	2011	230
85	56.55	50.83	2011 - 2012	85
247	54.21	48.99	2011 - 2012	247
161	56.00	51.29	2011 - 2012	161
286	52.90	48.70	2011 - 2012	286
87	48.86	45.16	2011 - 2013	87
291	50.25	47.06	2011 - 2013	291
95	45.14	42.46	2011 - 2013	95
9	38.70	36.54	2011 - 2013	9
794	42.05	40.40	2012 - 2014	533
42	47.19	45.97	2012 - 2014	28
19	38.76	37.95	2012 - 2014	12
11	23.58	23.36	2012 - 2014	7
1,230	17.11	17.11	2013 - 2015	278
17	19.30	19.30	2013 - 2015	2
17	25.97	25.97	2013 - 2015	5
8	22.76	22.76	2013 - 2015	3
4	23.65	23.65	2013 - 2015	1
1,561	23.58	23.58	2014 - 2016	–
36	23.05	23.05	2014 - 2016	–
16	24.30	24.30	2014 - 2016	–
6	30.32	30.32	2014 - 2016	–
5,457	$ 33.81	$ 32.11		2,565

A new stock option plan was approved by unitholders in conjunction with the corporate conversion and no further grants will be made under the Rights Incentive Plan. Outstanding trust unit rights on January 1, 2011 were adjusted to entitle rights holders to purchase common shares of Enerplus Corporation 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 in the same manner as was previously done for distributions.

(e) Basic and Diluted per Trust Unit Calculations

Basic per-unit calculations are calculated using the weighted average number of trust units and exchangeable partnership units (converted at the 0.425 exchange ratio) outstanding during the period. Diluted per-unit calculations include additional trust units for the dilutive impact of rights outstanding pursuant to the Rights Incentive Plan.

Net income per trust unit has been determined based on the following:

(thousands)	2010	2009
Weighted average units	**177,737**	169,280
Dilutive impact of rights	**353**	269
Diluted trust units	**178,090**	169,549

In 2010 a total of 2,078,000 rights were excluded as their exercise price was greater than the annual average unit market price of $25.13. In 2009 a total of 3,047,000 rights were excluded as their exercise price was greater than the annual average unit market price of $23.61.

(f) Long-Term Incentive Plans

Compensation expenses associated with the Performance Trust Unit ("PTU") plan and Restricted Trust Unit ("RTU") plan are determined based on the intrinsic value of these units at each period end. The number of notional trust units awarded varies by individual and vests one-third each for three years. Upon vesting, the plan participant receives a cash payment based on the fair value of the underlying trust units plus accrued distributions. The units are not exercisable and expire upon vesting.

For the year ended December 31, 2010 Enerplus recorded cash compensation costs of $17,580,000 (2009 – $11,409,000) for these plans which are included in general and administrative expenses.

The following table summarizes the PTU and RTU activity for the year ended December 31, 2010.

(thousands)	Number of PTU	Number of RTU
Balance, beginning of year	**237**	**867**
Granted	**–**	**603**
Vested	**(180)**	**(271)**
Forfeited	**(57)**	**(200)**
Balance, end of year*	**–**	**999**

* The final PTU's vested December 31, 2010 and were paid in 2011.

After January 1, 2011 RTU values will be based on Enerplus Corporation common shares and future dividends along with the applicable historical distributions.

12. INCOME TAXES

Enerplus Resources Fund was an inter-vivos trust for income tax purposes and any income that was not allocated to the Fund's unitholders was taxable. The Fund allocated all its income to unitholders in 2010.

The future income tax liabilities and assets on the balance sheet arise as a result of the following temporary differences:

	Future Income Tax Liability / (Asset)		
($ thousands)	Canadian	Foreign	2010 Total
Excess of net book value of PP&E over tax bases	**$ 329,741**	**$ 226,031**	**$ 555,772**
Asset retirement obligations	**(53,241)**	**–**	**(53,241)**
Other	**(6,682)**	**(4,047)**	**(10,729)**
Future income taxes	**$ 269,818**	**$ 221,984**	**$ 491,802**
Current future income tax asset	**$ (10,782)**	**$ –**	**$ (10,782)**
Long-term future income tax liability	**$ 280,600**	**$ 221,984**	**$ 502,584**

	Future Income Tax Liability / (Asset)		
($ thousands)	Canadian	Foreign	2009 Total
Excess of net book value of PP&E over tax bases	$ 427,757	$ 176,783	$ 604,540
Asset retirement obligations	(59,544)	–	(59,544)
Other	15,828	(4,234)	11,594
Future income taxes	$ 384,041	$ 172,549	$ 556,590
Current future income tax asset	$ (4,995)	$ –	$ (4,995)
Long-term future income tax liability	$ 389,036	$ 172,549	$ 561,585

The provision for income taxes varies from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

($ thousands)	2010	2009
Income/(loss) before taxes	**$ 41,933**	$ (3,876)
Computed income tax expense at the enacted rate of 28.41% (29.25% for 2009)	**$ 11,913**	$ (1,134)
Increase/(decrease) resulting from:		
Net income attributed to the Fund	**(69,924)**	(72,561)
Recognition of realized capital losses	**(13,216)**	–
Non-taxable portion of (gains)/losses	**(5,949)**	(9,144)
Amended returns and pool balances	**(6,894)**	(6,119)
Change in tax rate	**–**	(8,340)
Other	**(1,109)**	4,305
	$ (85,179)	$ (92,993)
Future income tax recovery	**$ (54,804)**	$ (93,191)
Current tax expense/(recovery)	**$ (30,375)**	$ 198

The detail of our current and future income tax balances between our Canadian and Foreign operations is as follows:

For the year ended December 31, 2010 ($ thousands)	Canadian	Foreign	Total
Future income tax expense/(recovery)	**$ (114,265)**	**$ 59,461**	**$ (54,804)**
Current income tax expense/(recovery)	**16,600**	**(46,975)**	**(30,375)**

For the year ended December 31, 2009 ($ thousands)	Canadian	Foreign	Total
Future income tax expense/(recovery)	$ (93,872)	$ 681	$ (93,191)
Current income tax expense/(recovery)	(48)	246	198

Enerplus is subject to normal course income tax audits by various taxation authorities. During the fourth quarter of 2010 Enerplus recorded a $16.6 million provision and corresponding charge to current income tax expense with respect to an ongoing income tax audit of a predecessor company from a prior corporate acquisition. At this time Enerplus is uncertain of the timing and final outcome of this matter.

13. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

(a) Carrying Value and Fair Value of Non-Derivative Financial Instruments

i. Cash

Cash is classified as held-for-trading and is reported at fair value, based on a Level 1 designation.

ii. Accounts Receivable

Accounts receivable are classified as loans and receivables which are reported at amortized cost. At December 31, 2010 the carrying value of accounts receivable approximated their fair value.

iii. Marketable Securities

Marketable securities with a quoted market price in an active market are classified as available-for-sale and are reported at fair value, with changes in fair value recorded in other comprehensive income. As at December 31, 2010 Enerplus reported investments in publicly traded marketable securities at a fair value of $743,000. For the year ended December 31, 2010 the change in fair value of these investments represented a gain of $293,000 ($251,000 net of tax). During 2009 Enerplus did not hold any investments in publicly traded marketable securities.

Marketable securities without a quoted market price in an active market are reported at cost unless an other than temporary impairment exists. Enerplus did not incur gains or losses with respect to such marketable securities during 2010. However, in 2009 Enerplus disposed of certain marketable securities which resulted in a loss of $2,191,400. As at December 31, 2010 Enerplus reported investments in marketable securities of private companies at cost of $50,156,000 (December 31, 2009 – $49,591,000) in Other Assets on the Consolidated Balance Sheet.

Realized gains and losses on marketable securities are included in other income.

iv. Accounts Payable & Distributions Payable to Unitholders

Accounts payable as well as distributions payable to unitholders are classified as other liabilities and are reported at amortized cost. At December 31, 2010 the carrying value of these accounts approximated their fair value.

v. Debt

Bank Credit Facilities

The bank credit facilities are classified as other liabilities and are reported at amortized cost. At December 31, 2010 the carrying value of the bank credit facilities approximated their fair value.

Senior Unsecured Notes

The senior unsecured notes, which are classified as other liabilities, are carried at their amortized cost and translated to Canadian dollars at the period end exchange rate. The following table details the amortized cost of the notes expressed in U.S. and Canadian dollars as well as the fair value expressed in Canadian dollars:

Original Principal Private Placement amount ($ thousands)	Amortized Cost	Reported CDN$ Amortized Cost	CDN$ Fair Value
CDN$40,000	CDN$40,000	$ 40,000	$ 43,238
US$40,000	US$40,000	39,784	44,410
US$225,000	US$225,000	223,785	264,564
US$54,000	US$54,000	53,709	57,845
US$175,000	US$141,176	140,414	148,992
		$ 497,692	$ 559,049

(b) Fair Value of Derivative Financial Instruments

Enerplus has assessed the relative inputs used in the determination of the fair value of all its derivative financial instruments and has determined that a fair value classification of Level 2 is appropriate for each of the instruments. A level 2 assignment is appropriate where observable inputs other than quoted prices are used in the fair value determination.

Enerplus' derivative financial instruments are classified as held for trading and are reported at fair value with changes in fair value recorded through earnings. The deferred financial assets and credits on the Consolidated Balance Sheet result from recording derivative financial instruments at fair value. At December 31, 2010 a current deferred financial asset of $12,641,000, a current deferred financial credit of $56,637,000, a non-current deferred financial asset of $385,000 and a non-current deferred financial credit of $46,943,000 are recorded on the Consolidated Balance Sheet.

The deferred financial credit relating to crude oil instruments is $38,344,000 at December 31, 2010 including deferred premiums of $4,011,000. The deferred financial asset relating to natural gas instruments is $12,641,000 at December 31, 2010 including deferred premiums of $347,000.

The following table summarizes the fair value as at December 31, 2010 and change in fair value for the year ended December 31, 2010.

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Commodity Derivative Instruments		Total
					Oil	Gas	
Deferred financial assets/(credits), beginning of year	$ (6,064)	$ (63,336)	$ 1,997	$ (2,481)	$ (20,344)	$ 20,364	$ (69,864)
Change in fair value gain/(loss)	2,424(1)	2,241(2)	(1,612)(3)	1,980(4)	(18,000)(5)	(7,723)(5)	(20,690)
Deferred financial assets/(credits), end of year	**$ (3,640)**	**$ (61,095)**	**$ 385**	**$ (501)**	**$ (38,344)**	**$ 12,641**	**$ (90,554)**
Balance sheet classification:							
Current asset/(liability)	**$ (2,468)**	**$ (15,324)**	**$ –**	**$ (501)**	**$ (38,344)**	**$ 12,641**	**$ (43,996)**
Non-current asset/(liability)	**$ (1,172)**	**$ (45,771)**	**$ 385**	**$ –**	**$ –**	**$ –**	**$ (46,558)**

(1) Recorded in interest expense.
(2) Recorded in foreign exchange expense (gain of $5,017) and interest expense (loss of $2,776).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments (see below).

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

($ thousands)	2010	2009
Gain/(loss) due to change in fair value	**$ (25,723)**	$ (120,913)
Net realized cash gain/(loss)	**49,719**	155,806
Commodity derivative instruments gain/(loss)	**$ 23,996**	$ 34,893

(c) Risk Management

Enerplus is exposed to a number of financial risks including market, counterparty credit and liquidity risk. Risk management policies have been established by Enerplus' Board of Directors to assist in managing a portion of these risks, with the goal of protecting earnings, cash flow and unitholder value.

i. Market Risk

Market risk is comprised of commodity price risk, currency risk and interest rate risk.

Commodity Price Risk

Enerplus is exposed to commodity price fluctuations as part of its normal business operations, particularly in relation to its crude oil and natural gas sales. Enerplus manages a portion of these risks through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts considered appropriate to a maximum of 80% of forecasted production volumes net of royalties.

Crude Oil Instruments:

Enerplus' crude oil financial contracts are classified as held-for-trading and are reported at fair value. At December 31, 2010 the fair value of these contracts represented a liability of $38,344,000 and the change in fair value of these contracts during 2010 represented an unrealized loss of $18,000,000.

The following table summarizes Enerplus' crude oil risk management positions at February 14, 2011:

	Daily Volumes bbls/day	WTI US$/bbl Purchased Call	Sold Put	Fixed Price and Swaps
Term				
Jan 1, 2011 – Dec 31, 2011				
Purchased Call	1,500	$ 105.00	–	–
Purchased Call	1,000	$ 100.00	–	–
Purchased Call	500	$ 92.00	–	–
Swap	1,000	–	–	$ 87.65
Swap	500	–	–	$ 85.20
Swap	500	–	–	$ 88.95
Swap	500	–	–	$ 91.20
Swap	500	–	–	$ 91.88
Swap	500	–	–	$ 92.65
Swap	500	–	–	$ 94.80
Swap	1,000	–	–	$ 82.36
Swap	500	–	–	$ 85.50
Swap	500	–	–	$ 86.25
Swap	500	–	–	$ 80.30
Swap	1,500	–	–	$ 82.60
Swap	500	–	–	$ 81.69
Swap	500	–	–	$ 84.25
Swap(1)	500	–	–	$ 85.40
Swap(1)	500	–	–	$ 87.70
Swap(1)	500	–	–	$ 86.73
Swap(1)	500	–	–	$ 87.51
Swap(1)	500	–	–	$ 89.20
Swap(1)	500	–	–	$ 89.65
Swap(1)	500	–	–	$ 87.20
Swap(1)	500	–	–	$ 88.00
Swap(1)	500	–	–	$ 89.00
Swap(1)	500	–	–	$ 90.00
Swap(1)	500	–	–	$ 91.25
Swap(1)	500	–	–	$ 90.75
Swap(1)	500	–	–	$ 92.40
Sold Put	1,500	–	$ 55.00	–
Sold Put	1,500	–	$ 58.00	–
Jan 1, 2012 – Dec 31, 2012				
Swap(1)	1,000	–	–	$ 90.40
Swap(1)	1,000	–	–	$ 90.18
Swap(1)	500	–	–	$ 91.84
Swap(1)	500	–	–	$ 92.25
Swap(2)	500	–	–	$ 95.00
Swap(2)	500	–	–	$ 95.50
Swap(2)	500	–	–	$ 100.15
Swap(2)	500	–	–	$ 99.35
Swap(2)	500	–	–	$ 99.40
Swap(2)	500	–	–	$ 100.50

(1) Financial contracts entered into during the fourth quarter of 2010.
(2) Financial contracts entered into subsequent to December 31, 2010.

Natural Gas Instruments:

Enerplus' natural gas financial contracts are classified as held-for-trading and are reported at fair value. At December 31, 2010 the fair value of these contracts represented an asset of $12,641,000 and the change in fair value of these contracts during 2010 represented an unrealized loss of $7,723,000.

The following table summarizes Enerplus' natural gas risk management positions at February 14, 2011:

		AECO CDN$/Mcf		
	Daily Volumes MMcf/day	Purchased Call	Sold Put	Fixed Price and Swaps
Term				
Jan 1, 2011 – Mar 31, 2011				
Swap	14.2	–	–	$ 6.20
Swap	4.7	–	–	$ 6.23
Swap	4.7	–	–	$ 6.24
Swap	4.7	–	–	$ 6.25
Swap	4.7	–	–	$ 6.17
Swap	9.5	–	–	$ 6.07
Swap	9.5	–	–	$ 6.81
Swap	9.5	–	–	$ 6.77
Swap	4.7	–	–	$ 6.66
Purchased Call	4.7	$ 7.91	–	–
Purchased Call	4.7	$ 7.39	–	–
Purchased Call	9.5	$ 6.86	–	–
Purchased Call	14.2	$ 6.38	–	–
Purchased Call	9.5	$ 5.18	–	–
Sold Put	19.0	–	$ 4.48	–
Sold Put	9.5	–	$ 3.96	–
Sold Put	9.5	–	$ 3.53	–
Sold Put	9.5	–	$ 4.37	–
Sold Put	4.7	–	$ 4.03	–

The following sensitivities show the impact to after-tax net income of the respective changes in forward crude oil and natural gas prices as at December 31, 2010 on Enerplus' outstanding contracts at that time with all other variables held constant:

	Increase/(decrease) to after-tax net income	
($ thousands)	25% decrease in forward prices	25% increase in forward prices
Crude oil derivative contracts	**$ 107,329**	**$ (99,533)**
Natural gas derivative contracts	**$ 981**	**$ (1,849)**

Electricity Instruments:

Enerplus has entered into electricity swaps that fix the price of electricity. These contracts are classified as held-for-trading and are reported at fair value. At December 31, 2010 the fair value of these contracts represented a liability of $501,000 and the change in fair value of these contracts during 2010 represented an unrealized gain of $1,980,000.

Unrealized gains or losses resulting from changes in fair value along with realized gains or losses on settlement of the electricity contracts are recognized as operating costs.

The following table summarizes Enerplus' electricity management positions at February 14, 2011:

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

(1) Financial contracts entered into during the fourth quarter of 2010.

Currency Risk

Enerplus is exposed to currency risk in relation to its U.S. dollar denominated working capital held in Canada and its U.S. dollar denominated senior unsecured notes. Enerplus manages the currency risk relating to its senior unsecured notes through the derivative instruments detailed below.

Cross Currency Interest Rate Swap ("CCIRS")

Concurrent with the issuance of the US$175,000,000 senior notes on June 19, 2002, Enerplus entered into a CCIRS with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal payments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%.

Foreign Exchange Swaps

In September 2007 Enerplus entered into foreign exchange swaps on US$54,000,000 of notional debt at an average US$/CDN$ foreign exchange rate of 0.98. These foreign exchange swaps mature between October 2011 and October 2015 in conjunction with the principal repayments on the US$54,000,000 senior notes.

The following sensitivities show the impact to after-tax net income of the respective changes in the period end and applicable forward foreign exchange rates as at December 31, 2010, with all other variables held constant:

	Increase/(decrease) to after-tax net income	
($ thousands)	**25% decrease in CDN$ relative to US$**	**25% increase in CDN$ relative to US$**
Translation of U.S. dollar denominated debt	**$ (98,278)**	**$ 98,278**
Translation of U.S. dollar denominated working capital	**32,248**	**(32,248)**
Total	**$ (66,030)**	**$ 66,030**

	Increase/(decrease) to after-tax net income	
($ thousands)	**25% decrease in CDN$ relative to US$**	**25% increase in CDN$ relative to US$**
Foreign exchange swaps	**$ 9,003**	**$ (8,657)**
Cross currency interest rate swap(1)	**23,289**	**(23,287)**
Total	**$ 32,292**	**$ (31,944)**

(1) Represents change due to foreign exchange rates only.

Interest Rate Risk

Enerplus' cash flows are impacted by fluctuations in interest rates as advances under the bank facility and payments made under the CCIRS are based on floating interest rates. To manage a portion of this interest rate risk, Enerplus has entered into interest rate swaps on $120,000,000 of notional debt at rates varying from 3.70% to 4.61% that mature between June 2011 and July 2013.

If interest rates change by 1%, either lower or higher, on Enerplus' effective outstanding variable rate debt at December 31, 2010 with all other variables held constant, Enerplus' after-tax net income for a year would change by $2,364,000.

The following sensitivities show the impact to after-tax net income of the respective changes in the applicable forward interest rates as at December 31, 2010, with all other variables held constant:

($ thousands)	Increase/(decrease) to after-tax net income: 25% decrease in forward interest rates	Increase/(decrease) to after-tax net income: 25% increase in forward interest rates
Interest rate swaps	**$ (475)**	**$ 475**
Cross currency interest rate swap[(1)]	**1,307**	**(1,307)**
Total	**$ 832**	**$ (832)**

(1) Represents change due to interest rates only.

ii. Credit Risk

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

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

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets as well as the fair value of its derivative financial assets. At December 31, 2010 approximately 98% of Enerplus' marketing receivables were with companies considered investment grade or just below investment grade.

At December 31, 2010 approximately $5,147,000 or 4% of Enerplus' total accounts receivable are aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production or net paying when the accounts are with joint venture partners. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at December 31, 2010 was $3,022,000 (2009 – $5,512,000).

iii. Liquidity Risk & Capital Management

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

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

Debt Levels

Enerplus commonly measures its debt levels relative to its "debt-to-cash flow ratio" which is defined as long-term debt (net of cash), divided by the trailing twelve-month cash flow from operating activities. The debt-to-cash flow ratio represents the time period, expressed in years, it would take to pay off the debt if no further capital investments were made or dividends paid and if cash flow from operating activities remained constant.

At December 31, 2010 the debt-to-cash flow ratio was 1.0x (December 31, 2009 – 0.6x). Enerplus expects that its debt-to-cash flow ratio will increase during 2011 and 2012 as it continues to invest in earlier stage growth assets where there is a longer lead time to production and cash flow. Enerplus will be actively monitoring its debt levels and may consider selling other assets to manage debt and maintain financial flexibility. Enerplus' debt-to-cash flow levels are anticipated to decrease after 2012 as production from growth plays accelerates.

Enerplus' bank credit facilities and senior note covenants carry a maximum debt-to-cash flow ratio of 3.0x including cash flow from acquisitions on a pro-forma basis. Traditionally Enerplus has managed its debt levels such that the debt-to-cash flow ratio has been below 1.5x, which has provided flexibility in pursuing acquisitions and capital projects. Enerplus' five-year history of debt-to-cash flow is illustrated below:

	2010	**2009**	**2008**	**2007**	**2006**
Debt-to-Cash Flow Ratio	**1.0x**	0.6x	0.5x	0.8x	0.8x

At December 31, 2010 Enerplus had additional borrowing capacity of $765,287,000 under its $1,000,000,000 bank credit facility. Enerplus does not have any subordinated or convertible debt outstanding at December 31, 2010.

14. COMMITMENTS AND CONTINGENCIES

(a) Pipeline Transportation

Enerplus has contracted to transport 200 MMcf/day of natural gas in Canada with contract terms that range anywhere from one month to five years. The Company has also contracted 6,000 MMbtu/day gas gathering capacity for its Marcellus production, which increases to 13,650 MMbtu/day on June 1, 2011 until March 31, 2022. In addition, the Company has contracted 4,500 MMbtu/day of transportation capacity on Columbia Gas Transmission for its Marcellus sales gas until January 2014.

Transportation for Enerplus' Bakken crude oil in the U.S. has been contracted for 1,000 bbl/day beginning May 2011 for five years and an additional 5,000 bbl/day commencing January 1, 2013 for five years.

(b) Office Lease

Enerplus has office lease commitments for both its U.S. and Canadian operations that expire in 2011 and 2014 respectively. Annual costs of these lease commitments include rent and operating fees.

(c) Guarantees

(i) Corporate indemnities have been provided by Enerplus to all directors and certain officers of its subsidiaries and affiliates for various items including, but not limited to, all costs to settle suits or actions due to their association with Enerplus and its subsidiaries and affiliates, subject to certain restrictions. Enerplus has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. Each indemnity, subject to certain exceptions, applies for so long as the indemnified person is a director or officer of one of Enerplus' subsidiaries and affiliates. The maximum amount of any potential future payment cannot be reasonably estimated.

(ii) Enerplus may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents Enerplus from making a reasonable estimate of the maximum potential amounts that may be required to be paid. Management believes the resolution of these matters would not have a material adverse impact on Enerplus' liquidity, consolidated financial position or results of operations.

(d) Capital Expenditures

In conjunction with the Marcellus acquisition on September 1, 2009 Enerplus committed to pay 50% of the operator's future drilling and completion costs up to an aggregate amount of US$246,600,000. The outstanding commitment balance at December 31, 2010 is approximately US$147,035,000. Enerplus expects that the remainder of the commitment will be incurred over the next two years.

In 2010 the Company entered into two contracts for drilling and fracturing services for its U.S. Fort Berthold operations. The contracts have a two year term beginning in early 2011 and have a monthly commitment of $4,600,000.

Enerplus has the following minimum annual commitments at December 31, 2010:

		Minimum Annual Commitment Each Year					Total Committed
($ thousands)	Total	2011	2012	2013	2014	2015	after 2015
Accounts payable[1]	**$ 350,623**	$ 350,623	$ –	$ –	$ –	$ –	$ –
Distributions payable to unitholders[2]	**32,157**	32,157	–	–	–	–	–
Bank credit facility[4]	**234,713**	–	–	234,713	–	–	–
Senior unsecured notes[3][4]	**573,113**	64,642	64,642	64,642	64,642	90,760	223,785
Pipeline commitments	**82,830**	16,788	12,617	13,976	12,400	11,470	15,579
Processing commitments	**20,293**	3,502	3,640	1,609	1,561	1,562	8,419
Marcellus carry commitment[5]	**146,241**	116,000	30,241	–	–	–	–
Drilling and completions[8]	**110,551**	42,712	55,276	12,563	–	–	–
Asset retirement obligations[7]	**590,177**	19,000	20,000	20,400	20,400	20,400	489,977
Office leases	**44,588**	11,351	11,395	11,375	10,467	–	–
Total commitments[6]	**$ 2,185,286**	$ 656,775	$ 197,811	$ 359,278	$ 109,470	$ 124,192	$ 737,760

(1) Accounts payable are generally settled between 30 and 90 days from the balance sheet date.
(2) Distributions payable to unitholders are paid on the 20th day of the month following the balance sheet date.
(3) Includes the economic impact of derivative instruments directly related to the senior unsecured notes (CCIRS and foreign exchange swap – see Note 13).
(4) Interest payments have not been included.
(5) The Marcellus carry commitment is based on estimated capital spending plans and has been converted to CDN$ using the December 31, 2010 foreign exchange rate of 1.0054.
(6) Crown and surface royalties, lease rentals, mineral taxes, and abandonment and reclamation costs (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(7) Based upon current spending estimates.
(8) US$ commitments have been converted to CDN$ using the December 31, 2010 foreign exchange rate of 1.0054.

Enerplus is subject to claims and litigation arising in the normal course of business. The resolution of these claims is uncertain and there can be no assurance they will be resolved in favor of Enerplus. However, management believes the resolution of these matters would not have a material adverse impact on the Company's liquidity, consolidated financial position or results of operations.

15. GEOGRAPHICAL INFORMATION

As at and for the year ended December 31, 2010 ($ thousands)	Canada	U.S.	Total
Oil and gas revenue	**$ 1,036,601**	**$ 290,539**	**$ 1,327,140**
Plant, property and equipment	**3,256,376**	**1,720,509**	**4,976,885**
Goodwill	**451,121**	**148,551**	**599,672**

As at and for the year ended December 31, 2009 ($ thousands)	Canada	U.S	Total
Oil and gas revenue	$ 1,059,067	$ 200,079	$ 1,259,146
Plant, property and equipment	4,213,559	786,964	5,000,523
Goodwill	451,121	156,317	607,438

16. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Fund's consolidated financial statements have been prepared in accordance with Canadian GAAP. These principles, as they pertain to the Fund's consolidated statements differ from U.S. GAAP as follows:

The application of U.S. GAAP would have the following effects on net income as reported:

($ thousands)	2010	2009
Net income as reported in the Consolidated Statement of Income – Canadian GAAP	**$ 127,112**	$ 89,117
Adjustments:		
Depletion, depreciation, amortization and accretion *(Note (a))*	**248,816**	177,637
Impairment of property, plant and equipment *(Note (a))*	**–**	(481,200)
Capitalized interest *(Note (b))*	**666**	527
Compensation expense *(Note (c))*	**(8,153)**	(1,449)
Income tax recovery/(expense) of adjustments above and impact of changes in tax rates	**(64,117)**	95,782
Net income/(loss) – U.S. GAAP	**$ 304,324**	$ (119,586)
Other comprehensive income/(loss) as reported in the Consolidated Statement of Comprehensive Income – Canadian GAAP	**$ (52,171)**	$ (130,993)
Adjustments:		
Cumulative translation adjustment *(Note (e))*	**7,168**	26,760
Other comprehensive income/(loss) – U.S. GAAP	**$ (45,003)**	$ (104,233)
Comprehensive income/(loss) – U.S. GAAP	**$ 259,321**	$ (223,819)
Net income/(loss) per trust unit		
Basic	**$ 1.71**	$ (0.71)
Diluted	**$ 1.71**	$ (0.71)
Weighted average number of trust units outstanding		
Basic	**177,737**	169,280
Diluted	**177,978**	169,392
Deficit:		
Balance, beginning of year – U.S. GAAP	**$ (1,053,647)**	$ (532,364)
Net income/(loss) – U.S. GAAP	**304,324**	(119,586)
Change in redemption value *(Note (d))*	**(975,182)**	(33,496)
Cash distributions	**(384,128)**	(368,201)
Balance, end of year – U.S. GAAP	**$ (2,108,633)**	$ (1,053,647)
Accumulated other comprehensive income/(loss):		
Balance, beginning of year – U.S. GAAP	**$ (55,627)**	$ 48,606
Other comprehensive income/(loss)	**(45,003)**	(104,233)
Balance, end of year – U.S. GAAP	**$ (100,630)**	$ (55,627)

The application of U.S. GAAP would have the following effects on the balance sheet as reported:

($ thousands)	Canadian GAAP	Increase/ (Decrease)	U.S. GAAP
December 31, 2010			
Assets:			
Property, plant and equipment, net *(Notes (a)(b))*	**$ 4,976,885**	**$ (1,931,038)**	**$ 3,045,847**
Liabilities:			
Trust unit rights liability *(Note (c))*	**$ –**	**$ 20,158**	**$ 20,158**
Future/Deferred income tax liability	**502,584**	**(494,078)**	**8,506**
Unitholders' mezzanine equity *(Note (d))*	**–**	**4,657,264**	**4,657,264**
Unitholders' Equity:			
Unitholders' capital *(Notes (c)(d))*	**$ 5,756,976**	**$ (5,756,976)**	**$ –**
Deficit *(Note (d))*	**1,717,299**	**391,334**	**2,108,633**
Accumulated other comprehensive loss *(Note (e))*	**134,558**	**(33,928)**	**100,630**
December 31, 2009			
Assets:			
Property, plant and equipment, net *(Notes (a)(b))*	$ 5,000,523	$ (2,187,689)	$ 2,812,834
Liabilities:			
Trust unit rights liability *(Note (c))*	$ –	$ 9,075	$ 9,075
Future/Deferred income tax liability	561,585	(558,195)	3,390
Unitholders' mezzanine equity *(Note (d))*	–	3,643,650	3,643,650
Unitholders' Equity:			
Unitholders' capital *(Note (c)(d))*	$ 5,715,614	$ (5,715,614)	$ –
Deficit *(Note (d))*	1,460,283	(406,636)	1,053,647
Accumulated other comprehensive loss *(Note (e))*	82,387	(26,760)	55,627

(a) Property, Plant and Equipment and Depletion, Depreciation, Amortization and Accretion

Under U.S. GAAP full cost accounting, the carrying value of petroleum and natural gas properties and related facilities, net of deferred income taxes, is limited to the present value of after tax future net revenue from proved reserves, discounted at 10%, plus the lower of cost or fair value of unproved properties. New SEC reserve estimation rules came into effect during 2009 which uses pricing based on a twelve-month average price of the first day of the month prices during the year. Under Canadian GAAP, impairment exists when the carrying amount exceeds the estimated undiscounted future net cash flows associated with Enerplus' proved reserves. If impairment is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with Enerplus' proved and probable reserves are charged to income.

As at December 31, 2010, no impairment of capitalized costs resulted from the application of the impairment test under either U.S. GAAP or Canadian GAAP. As at December 31, 2009, the application of the impairment test under U.S. GAAP resulted in a write-down of $481,200,000 ($363,402,000 net of tax) whereas there was no impairment under Canadian GAAP.

Where the amount of impairment under Canadian GAAP differs from the amount of the impairment under U.S. GAAP, the charge for DDA&A will differ in subsequent years. Historically Enerplus' U.S. GAAP impairments have exceeded the Canadian GAAP impairments, resulting in lower U.S. GAAP DDA&A charges compared to Canadian GAAP. A U.S. GAAP difference also exists relating to the basis of measurement of proved reserves that is utilized in the depletion calculation. Under U.S. GAAP, depletion charges are calculated by reference to proved reserves estimated based on a twelve-month average price. Under Canadian GAAP, depletion charges are calculated by reference to proved reserves estimated using future prices. For the year ended December 31, 2010 DDA&A calculated under U.S. GAAP was $248,816,000 ($184,870,000 net of tax) lower than DDA&A calculated under Canadian GAAP. For the year ended December 31, 2009 DDA&A calculated under U.S. GAAP was $177,637,000 ($134,151,000 net of tax) lower than DDA&A calculated under Canadian GAAP.

(b) Interest Capitalization

U.S. GAAP requires interest expense to be capitalized for development projects that have not reached commercial production. A U.S. GAAP difference exists as there is not a similar requirement under Canadian GAAP. For the year ended December 31, 2010 Enerplus capitalized interest of $666,000 ($495,000 net of tax) (2009 – $527,000, $398,000 net of tax) related to projects under development.

(c) Unit-based Compensation

A U.S. GAAP difference exists as rights granted under Enerplus' trust unit rights incentive plan are considered liability awards for U.S. GAAP and equity awards under Canadian GAAP. The distinction between a liability award and an equity award has an impact on the related accounting treatment.

Under Canadian GAAP rights are accounted for using the fair value method for an equity award. Under this method, the fair value of the right is determined using a binomial lattice option-pricing model on the grant date and is not subsequently remeasured. This amount is charged to earnings over the vesting period of the rights, with a corresponding increase in contributed surplus. When rights are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to unitholders' capital.

Under U.S. GAAP rights are accounted for using the fair value method for a liability award. Under this method, the trust unit rights liability is calculated based on the rights fair value determined using a binomial lattice option-pricing model at each reporting date until the date of settlement. The compensation cost for each period is based on the change in the fair value of the rights for each reporting period. When rights are exercised, the proceeds, together with the amount recorded as a trust unit rights liability, are recorded to mezzanine equity.

The following assumptions were used to arrive at the estimate of fair value as at December 31 for each respective year:

	2010	2009
Dividend yield	**7.12%**	9.13%
Volatility	**44.23%**	44.22%
Risk-free interest rate	**2.23%**	2.48%
Forfeiture rate	**12.50%**	12.40%
Right's exercise price reduction	**$ 0.74**	$ 1.41

The weighted average grant date fair value of trust unit rights granted in 2010 was $4.04 per trust unit right (2009 – $3.32). The total intrinsic value of trust unit rights exercised during 2010 was $3,014,000 (2009 – $12,000).

As at December 31, 2010, 2,565,000 trust unit rights were exercisable at a weighted average reduced exercise price of $42.27 with a weighted average remaining contractual term of 2.8 years, giving an aggregate intrinsic value of $3,907,000. As at December 31, 2009, 2,393,000 trust unit rights were exercisable at a weighted average reduced exercise price of $46.03 with a weighted average remaining contractual term of 3.2 years, giving an aggregate intrinsic value of $5,000.

The following chart details the U.S. GAAP differences related to Enerplus' trust unit rights plan for the years ended December 31, 2010 and 2009.

	2010			2009		
($ thousands)	**CDN GAAP**	**U.S. GAAP**	**Difference**	**CDN GAAP**	**U.S. GAAP**	**Difference**
Compensation expense	**$ 5,944**	**$ 14,097**	**$ 8,153**	$ 6,542	$ 7,991	$ 1,449
Contributed Surplus	**$ 30,290**	**$ –**	**$ (30,290)**	$ 26,142	$ –	$ (26,142)
Trust unit rights liability	**$ –**	**$ 20,158**	**$ 20,158**	$ –	$ 9,075	$ 9,075

(d) Unitholders' Mezzanine Equity

A U.S. GAAP difference exists as a result of the redemption feature in Enerplus' trust units including the equivalent limited partnership units. Trust units are redeemable at the option of the holder for approximately 85% of the current trading price. For Canadian GAAP, the trust units are considered to be permanent equity and are presented as unitholders' capital. Under U.S. GAAP, the redemption feature of the trust units excludes them from classification as permanent equity and results in the trust units being classified as mezzanine equity.

For U.S. GAAP Enerplus has recorded unitholders' mezzanine equity in the amount of $4,657,264,000 for 2010 (2009 – $3,643,650,000), which represents the estimated redemption value of the trust units including the equivalent limited partnership units at 85% of the year-end market price. In addition, Enerplus has recognized a deficit of $2,108,633 for 2010 (2009 – $1,053,647,000) resulting from eliminating unitholders' capital and replacing it with unitholders' mezzanine equity at redemption value. Changes in unitholders' mezzanine equity in excess of trust units issued, net of redemptions, are recorded to the deficit.

(e) Accumulated Other Comprehensive Income/(Loss) ("AOCI")

A U.S. GAAP difference exists with respect to the AOCI balance due to differences in the cumulative translation adjustment as a result of other U.S. GAAP adjustments. Enerplus' AOCI balance under U.S. GAAP was a deficit of $100,630,000 as at December 31, 2010.

(f) Income Taxes

Each year Enerplus reviews the balance of its estimated tax liabilities and determines whether the recognition and measurement criteria have changed. Where the criteria are no longer met, the liability is reversed and a tax recovery is recognized during that period. In addition, where the filing positions taken in the current year do not meet the measurement criteria, a liability will be recorded and an expense recognized.

An unrecognized tax benefit is defined as the difference between tax positions taken in a tax return and amounts recognized in the financial statements. Enerplus recognizes potential accrued interest and penalties related to unrecognized tax benefits in its Consolidated Statements of Income. The following table summarizes the activity related to our unrecognized tax benefits for 2010 and 2009:

($ thousands)	2010	2009
Balance, beginning of year	**$ 720**	$ 700
Additional unrecognized tax benefits	**12,600**	–
Interest	**4,055**	20
Balance, end of year	**$ 17,375**	$ 720

The additional unrecognized tax benefit of $12,600,000 related to a prior year and if recognized, it would change the effective tax rate in the year recognized. Enerplus does not expect that any of the unrecognized tax benefits will be recognized in the next twelve months.

In most cases any uncertain tax positions are related to taxation years that remain subject to examination by the relevant taxation authorities. The open taxation years for which no examination has been initiated or the examination is in progress is 2004 onward for Canada and 2007 onward for the United States.

(g) Additional Disclosures Required under U.S. GAAP

i. The components of accounts receivable are as follows:

As at December 31 ($ thousands)	2010	2009
Oil & Gas sales and accruals	**$ 93,643**	$ 79,260
Joint venture	**35,310**	42,179
Other	**–**	26,082
Less: Allowance for doubtful accounts	**(3,025)**	(5,512)
	$ 125,928	$ 142,009

ii. The components of accounts payable are as follows:

As at December 31 ($ thousands)	2010	2009
Contractors and vendors	**$ 55,990**	$ 55,238
Accrued liabilities	**294,633**	202,281
	$ 350,623	$ 257,519

iii. Net Oil and Gas Sales

Under U.S. GAAP oil and gas sales are presented net of royalties.

For the year ended December 31 ($ thousands)	2010	2009
Oil and Gas sales	**$ 1,327,140**	$ 1,259,146
Royalties	**(223,459)**	(207,491)
Net Oil and Gas sales	**$ 1,103,681**	$ 1,051,655

iv. Consolidated Cash Flows:

The Consolidated Statements of Cash Flows prepared in accordance with Canadian GAAP present operating cash flow before changes in non-cash working capital items. This sub-total cannot be presented under U.S. GAAP.

The following summarizes the effect to cash flow from changes in non-cash working capital:

For the year ended December 31 ($ thousands)	2010	2009
Accounts receivable	**$ 16,081**	$ 21,143
Other current	**(44,565)**	(1,258)
Accounts payable	**93,104**	(15,299)
Distributions payable to unitholders	**287**	(9,526)
Other	**12,627**	(23,848)
Total change in non-cash working capital	**$ 77,534**	$ (28,788)
Relating to:		
Operating activities	**$ (15,623)**	$ 26,220
Financing activities	**287**	(9,526)
Investing activities	**92,870**	(45,482)
	$ 77,534	$ (28,788)

v. Subsequent Events:

U.S. GAAP requires disclosure that subsequent events have been updated to February 24, 2011.

(h) U.S. Pronouncements

The following accounting pronouncement was adopted during 2010:

- Amendments to Consolidation of Variable Interest Entities – intended to address (1) the effects on certain consolidation provisions as a result of the elimination of the concept of qualifying special-entities and (2) constituent concerns about the application of certain consolidation provisions including those in which the accounting and disclosures do not always provide timely and useful information about and enterprise's involvement in a variable interest entity. The adoption of the provisions on January 1, 2010 did not have any impact to Enerplus' consolidated results of operations, financial position or cash flows.

Future accounting pronouncements:

- IFRS financial statements – the U.S. Securities and Exchange Commission has issued final rules to accept from foreign private issuers financial statements prepared in accordance with IFRS without reconciliation to U.S. GAAP. Enerplus, as a foreign private issuer, adopted IFRS on January 1, 2011.

5 YEAR DETAILED STATISTICAL REVIEW

($ thousands, except per unit amounts)	2010	2009	2008	2007	2006
Financial					
Oil and gas sales[(1)]	**$ 1,324,177**	$ 1,267,656	$ 2,370,668	$ 1,464,214	$ 1,569,487
Cash flow from operating activities	**703,148**	775,786	1,262,782	868,548	863,696
Cash distributions to unitholders	**384,128**	368,201	786,138	646,835	614,340
Per unit	**2.16**	2.17	4.89	5.04	5.04
Cash withheld for acquisitions and capital expenditures	**319,020**	407,585	476,644	221,713	249,356
Development capital spending	**542,679**	299,111	577,739	387,165	491,226
Acquisitions	**1,018,069**	271,977	1,772,826	274,244	51,313
Divestments	**871,458**	104,325	504,859	9,572	21,127
Total net capital expenditures	**693,294**	473,517	1,856,305	658,327	526,387
Total assets	**5,835,172**	5,905,516	6,230,132	4,303,130	4,203,804
Long-term debt, net of cash	**724,031**	485,349	657,421	724,975	679,650
Payout ratio[(2)]	**55%**	47%	62%	74%	71%
Net debt/cash flow ratio	**1.0x**	0.6x	0.5x	0.8x	0.8x
Trust Unit Trading Information					
Canadian trading summary[(5)]					
Close	**$ 30.67**	$ 24.21	$ 23.96	$ 39.87	$ 50.68
Volume	**127,386**	98,597	127,679	96,898	82,120
U.S. trading summary[(6)]					
Close	**$ 30.84**	$ 22.96	$ 19.58	$ 40.05	$ 43.61
Volume	**168,979**	191,405	235,270	121,348	139,094
Weighted average number of units outstanding (basic)	**177,737**	169,280	160,589	127,691	121,588
Number of units outstanding at December 31	**178,648**	177,061	165,590	129,813	123,151
Average Benchmark Pricing					
AECO natural gas (per Mcf)	**$ 4.13**	$ 4.14	$ 8.13	$ 6.61	$ 6.99
NYMEX natural gas (US$ per Mcf)	**4.42**	4.03	8.93	6.92	7.26
WTI crude oil (US$ per bbl)	**79.53**	61.80	99.65	72.34	66.22
US$/CDN$ exchange rate	**0.97**	0.88	0.94	0.93	0.88
($ per BOE except percentage data)					
Oil and Gas Economics					
Net royalty rate	**17%**	17%	19%	19%	19%
Weighted average price[(3)]	**$ 42.85**	$ 36.89	$ 65.79	$ 50.48	$ 50.23
Commodity derivative instruments[(4)]	**1.64**	4.66	(2.94)	0.45	(1.10)
Weighted average price[(1)]	**44.49**	41.55	62.85	50.93	49.13
Net royalty expense	**7.37**	6.21	12.27	9.49	9.36
Operating expense[(4)]	**9.61**	9.71	9.51	9.11	8.02
Operating netback	**27.51**	25.63	41.07	32.33	31.75
General and administrative expense[(4)]	**2.40**	2.44	1.68	1.98	1.71
Interest, foreign exchange and other expenses[(4)]	**1.85**	0.34	1.59	1.43	0.93
Taxes	**(1.00)**	0.01	0.65	0.77	0.70
Restoration and abandonment cash costs	**0.57**	0.41	0.52	0.54	0.37
Cash flow before changes in non-cash working capital	**$ 23.69**	$ 22.43	$ 36.63	$ 27.61	$ 28.04

(1) Net of commodity derivative instruments and transportation.
(2) Calculated as cash distributions to unitholders divided by cash flow from operating activities.
(3) Net of transportation and before the effects of commodity derivative instruments.
(4) Does not include non-cash portion of expense.
(5) TSX data prior to 2010, Canadian composite trading data including TSX thereafter.
(6) NYSE data prior to 2008, U.S. composite trading data including NYSE thereafter.

5 YEAR OPERATIONAL STATISTICS

The following information outlines Enerplus' gross average daily production volumes for the years indicated and our Company interest reserves based upon forecast prices and costs at December 31 each year.

	2010(1)	2009(1)	2008(1)	2007(1)	2006(1)
Daily Production					
Oil Sands	**n/a**	n/a	n/a	n/a	n/a
Crude Oil (bbls/day)	**31,135**	32,984	34,581	34,506	36,134
NGLs (bbls/day)	**3,889**	4,157	4,627	4,104	4,483
Natural Gas (Mcf/day)	**288,692**	326,570	338,869	262,254	270,972
BOE per day	**83,139**	91,569	95,687	82,319	85,779
Drilling Activity (net wells)	**226**	313	643	252	361
Success Rate	**99%**	99%	99%	99%	99%
Proved Reserves(2)					
Oil Sands	**–**	–	–	8,568	8,730
Crude Oil (Mbls)	**109,706**	120,936	127,692	125,238	125,048
NGLs (Mbbls)	**8,610**	10,753	13,052	11,785	12,690
Natural Gas (MMcf)	**554,090**	746,034	1,066,534	866,077	920,061
Shale Gas (MMcf)	**52,225**	8,127	–	–	–
MBOE	**219,369**	257,382	318,500	289,937	299,812
Probable Reserves(2)					
Oil Sands	**–**	–	–	54,930	47,998
Crude Oil (Mbls)	**40,147**	36,410	38,931	35,504	34,421
NGLs (Mbbls)	**2,966**	3,754	4,765	3,827	3,777
Natural Gas (MMcf)	**198,097**	267,146	421,134	336,214	344,025
Shale Gas (MMcf)	**64,437**	16,763	–	–	–
MBOE	**83,868**	87,482	113,885	150,297	143,533
Proved Plus Probable Reserves(2)					
Oil Sands	**–**	–	–	63,498	56,728
Crude Oil (Mbls)	**149,853**	157,346	166,623	160,742	159,469
NGLs (Mbbls)	**11,576**	14,507	17,817	15,612	16,467
Natural Gas (MMcf)	**752,187**	1,013,180	1,487,668	1,202,291	1,264,086
Shale Gas (MMcf)	**116,662**	24,890	–	–	–
MBOE	**306,237**	344,864	432,385	440,234	443,345
Reserve Life Index(3)					
Without Oil Sands:					
Proved (years)	**8.2**	8.2	9.4	10.0	9.8
Proved Plus Probable (years)	**10.7**	10.9	12.1	12.8	12.2

(1) Reserve information reflects NI 51-101 reporting methodology.
(2) Company interest reserves consist of gross revenues (as defined in National Instrument 51-101) plus the Company's royalty interests. Company interest reserves are not a term defined in National Instrument 51-101 and may not be comparable to reserves disclosed by other issuers.
(3) The Reserve Life Indices (RLI) are based upon year-end proved plus probable reserves divided by the following year's proved and proved plus probable production volumes as determined in the independent reserve engineering reports.

SUPPLEMENTAL INFORMATION

RESERVES

All reserves are presented on a "company interest" basis. All of our reserves, including our U.S. reserves, were evaluated using Canadian National Instrument 51-101 ("NI 51-101") standards. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated or reviewed all of our Canadian assets, and in August 2010, Enerplus contracted McDaniel to replace Netherland, Sewell & Associates, Inc. as our independent reserve evaluator for our western United States assets. Haas Petroleum Engineering Services Inc. ("Haas") has evaluated our Marcellus shale gas assets again this year.

McDaniel has evaluated 86% of the total proved plus probable value (discounted at 10%) of our Canadian conventional year-end reserves and reviewed the internal evaluation completed by Enerplus on the remaining 14% of reserves. McDaniel also evaluated substantially all of the reserves associated with our western U.S. assets with the exception of some minor royalty interest properties which were evaluated internally and reviewed by McDaniel. The evaluation of contingent resources associated with our Bakken leases at Fort Berthold was conducted by Enerplus and reviewed by McDaniel. Haas evaluated 100% of our Marcellus shale gas assets in the U.S. and provided both the reserve and contingent resource estimates.

Reserves & Contingent Resources by Resource Play

Play Types	Proved	Proved plus Probable Reserves	Proved plus Probable Booked Net Drilling Locations	"Best Estimate" Contingent Resources*	Incremental Future Contingent Resource Net Drilling Locations
Bakken/Tight Oil (MMBOE)	38.0	57.5	39	60	90
Crude Oil Waterfloods (MMBOE)	65.2	83.7	45	–	–
Other Conventional Oil (MMBOE)	20.8	27.7	23	–	–
Total Oil (MMBOE)	124.0	168.9	107	60	90
Marcellus Shale Gas (Bcfe)	52.4	117.2	13	3,904	926
Tight Gas (Bcfe)	228.7	320.8	40	–	–
Shallow Gas (Bcfe)	164.8	220.5	152	–	–
Other Conventional Gas (Bcfe)	126.3	165.0	1	–	–
Total Gas (Bcfe)	572.2	823.5	206	3,904	926
Total Company (MMBOE)	219.4	306.2	313	710.7	1,016

* Contingent resources net to Enerplus. No contingent resource assessment has been conducted on our waterflood, tight gas, shallow gas or other conventional oil and gas assets at this time.

Reserves Summary

The following table sets out our company interest volumes at December 31, 2010 by production type and reserve category under McDaniel's forecast price scenario set forth below. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit and reserves associated with a property.

2010 Reserves Summary – Company Interest Volumes (Forecast Prices)

Reserves Category	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Developed Producing							
Canada	46,028	25,955	71,983	7,627	456,777	–	155,739
United States	21,880	–	21,880	67	34,566	32,014	33,044
Total Proved Developed Producing	67,908	25,955	93,863	7,694	491,343	32,014	188,783
Proved Developed Non-Producing							
Canada	347	687	1,034	175	12,883	–	3,357
United States	1,193	–	1,193	1	1,115	2,508	1,798
Total Proved Developed Non-Producing	1,540	687	2,227	176	13,998	2,508	5,155
Proved Undeveloped						–	
Canada	3,233	2,535	5,768	713	40,389	–	13,212
United States	7,848	–	7,848	27	8,360	17,703	12,219
Total Proved Undeveloped	11,081	2,535	13,616	740	48,749	17,703	25,431
Proved						–	
Canada	49,608	29,177	78,785	8,515	510,049	–	172,308
United States	30,921	–	30,921	95	44,041	52,225	47,061
Total Proved	80,529	29,177	109,706	8,610	554,090	52,225	219,369
Probable						–	
Canada	14,098	9,783	23,881	2,825	173,983	–	55,703
United States	16,266	–	16,266	141	24,114	64,437	31,165
Total Probable	30,364	9,783	40,147	2,966	198,097	64,437	86,868
Proved Plus Probable						–	
Canada	63,706	38,960	102,666	11,340	684,032	–	228,011
United States	47,187	–	47,187	236	68,155	116,662	78,226
Total Proved Plus Probable	110,893	38,960	149,853	11,576	752,187	116,662	306,237

Reserve Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a company interest basis, from December 31, 2009 to December 31, 2010.

Proved Reserves – Company Interest Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2009	61,053	34,431	95,484	10,633	696,585	–	222,214
Acquisitions	249	–	249	30	2,235	–	652
Dispositions	(11,001)	(4,207)	(15,208)	(1,346)	(50,085)	–	(24,902)
Discoveries	–	–	–	–	–	–	–
Extensions & Improved Recovery	3,505	15	3,520	138	12,431	–	5,730
Economic Factors	(86)	(17)	(103)	(230)	(33,414)	–	(5,902)
Technical Revisions	866	1,902	2,768	709	(20,366)	–	83
Production	(4,978)	(2,947)	(7,925)	(1,419)	(97,337)	–	(25,567)
Proved Reserves at Dec. 31, 2010	49,608	29,177	78,785	8,515	510,049	–	172,308

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2009	25,452	–	25,452	120	49,449	8,127	35,168
Acquisitions	4,799	–	4,799	–	1,191	–	4,998
Dispositions	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–
Extensions & Improved Recovery	6,379	–	6,379	27	2,096	35,767	12,717
Economic Factors	40	–	40	–	12	–	42
Technical Revisions	(2,329)	–	(2,329)	(33)	(4,035)	11,696	(1,085)
Production	(3,420)	–	(3,420)	(19)	(4,672)	(3,365)	(4,779)
Proved Reserves at Dec. 31, 2010	30,921	–	30,921	95	44,041	52,225	47,061

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2009	86,505	34,431	120,936	10,753	746,034	8,127	257,382
Acquisitions	5,048	–	5,048	30	3,426	–	5,650
Dispositions	(11,001)	(4,207)	(15,208)	(1,346)	(50,085)	–	(24,902)
Discoveries	–	–	–	–	–	–	–
Extensions & Improved Recovery	9,884	15	9,899	165	14,527	35,767	18,447
Economic Factors	(46)	(17)	(63)	(230)	(33,402)	–	(5,860)
Technical Revisions	(1,463)	1,902	439	676	(24,401)	11,696	(1,002)
Production	(8,398)	(2,947)	(11,345)	(1,438)	(102,009)	(3,365)	(30,346)
Proved Reserves at Dec. 31, 2010	80,529	29,177	109,706	8,610	554,090	52,225	219,369

Probable Reserves – Company Interest Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2009	16,776	12,347	29,123	3,718	250,061	–	74,518
Acquisitions	56	–	56	17	(1,004)	–	(95)
Dispositions	(4,060)	(1,650)	(5,710)	(447)	(17,930)	–	(9,145)
Discoveries	–	–	–	–	–	–	–
Extensions & Improved Recovery	1,699	10	1,709	84	6,991	–	2,958
Economic Factors	(34)	(16)	(50)	(21)	(15,150)	–	(2,596)
Technical Revisions	(339)	(908)	(1,247)	(526)	(48,985)	–	(9,937)
Production	–	–	–	–	–	–	–
Probable Reserves at Dec. 31, 2010	14,098	9,783	23,881	2,825	173,983	–	55,703

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2009	7,287	–	7,287	36	17,085	16,763	12,964
Acquisitions	5,890	–	5,890	–	2,359	–	6,283
Dispositions	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–
Extensions & Improved Recovery	4,129	–	4,129	70	3,016	51,325	13,255
Economic Factors	38	–	38	–	33	–	44
Technical Revisions	(1,078)	–	(1,078)	35	1,621	(3,651)	(1,381)
Production	–	–	–	–	–	–	–
Probable Reserves at Dec. 31, 2010	16,266	–	16,266	141	24,114	64,437	31,165

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2009	24,063	12,347	36,410	3,754	267,146	16,763	87,482
Acquisitions	5,946	–	5,946	17	1,355	–	6,188
Dispositions	(4,060)	(1,650)	(5,710)	(447)	(17,930)	–	(9,145)
Discoveries	–	–	–	–	–	–	–
Extensions & Improved Recovery	5,828	10	5,838	154	10,007	51,325	16,213
Economic Factors	4	(16)	(12)	(21)	(15,117)	–	(2,552)
Technical Revisions	(1,417)	(908)	(2,325)	(491)	(47,364)	(3,651)	(11,318)
Production	–	–	–	–	–	–	–
Probable Reserves at Dec. 31, 2010	30,364	9,783	40,147	2,966	198,097	64,437	86,868

Proved Plus Probable Reserves – Company Interest Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2009	77,829	46,778	124,607	14,351	946,646	–	296,732
Acquisitions	305	–	305	47	1,231	–	557
Dispositions	(15,061)	(5,857)	(20,918)	(1,793)	(68,015)	–	(34,047)
Discoveries	–	–	–	–	–	–	–
Extensions & Improved Recovery	5,204	25	5,229	222	19,422	–	8,688
Economic Factors	(120)	(33)	(153)	(251)	(48,564)	–	(8,498)
Technical Revisions	527	994	1,521	183	(69,351)	–	(9,854)
Production	(4,978)	(2,947)	(7,925)	(1,419)	(97,337)	–	(25,567)
Proved Plus Probable Reserves at Dec. 31, 2010	**63,706**	**38,960**	**102,666**	**11,340**	**684,032**	**–**	**228,011**

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2009	32,739	–	32,739	156	66,534	24,890	48,132
Acquisitions	10,689	–	10,689	–	3,550	–	11,281
Dispositions	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–
Extensions & Improved Recovery	10,508	–	10,508	97	5,112	87,092	25,972
Economic Factors	78	–	78	–	45	–	86
Technical Revisions	(3,407)	–	(3,407)	2	(2,414)	8,045	(2,466)
Production	(3,420)	–	(3,420)	(19)	(4,672)	(3,365)	(4,779)
Proved Plus Probable Reserves at Dec. 31, 2010	**47,187**	**–**	**47,187**	**236**	**68,155**	**116,662**	**78,226**

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2009	110,568	46,778	157,346	14,507	1,013,180	24,890	344,864
Acquisitions	10,994	–	10,994	47	4,781	–	11,838
Dispositions	(15,061)	(5,857)	(20,918)	(1,793)	(68,015)	–	(34,047)
Discoveries	–	–	–	–	–	–	–
Extensions & Improved Recovery	15,712	25	15,737	319	24,534	87,092	34,660
Economic Factors	(42)	(33)	(75)	(251)	(48,519)	–	(8,412)
Technical Revisions	(2,880)	994	(1,886)	185	(71,765)	8,045	(12,320)
Production	(8,398)	(2,947)	(11,345)	(1,438)	(102,009)	(3,365)	(30,346)
Proved Plus Probable Reserves at Dec. 31, 2010	**110,893**	**38,960**	**149,853**	**11,576**	**752,187**	**116,662**	**306,237**

NET PRESENT VALUE OF FUTURE PRODUCTION REVENUE

The estimated reserve volumes and net present values of all future net revenues at December 31, 2010 were based upon forecast crude oil and natural gas pricing assumptions prepared by McDaniel as of December 31, 2010. These prices were applied to the reserves evaluated by McDaniel and Haas, along with those evaluated internally by Enerplus and audited by McDaniel. The base reference prices and exchange rates used by McDaniel are detailed below:

McDaniel January 2011 Forecast Price Assumptions

	WTI Crude Oil US$/bbl	Light Crude Oil(1) Edmonton CDN$/bbl	Hardisty Heavy Oil 12° API CDN$/bbl	Henry Hub Gas Price US$/MMBtu	Natural Gas 30 day spot @ AECO CDN$/MMBtu	Exchange Rate US$/CDN$
2011	85.00	84.20	66.70	4.55	4.25	0.975
2012	87.70	88.40	68.70	5.30	4.90	0.975
2013	90.50	91.80	68.60	5.75	5.40	0.975
2014	93.40	94.80	70.80	6.30	5.90	0.975
2015	96.30	97.70	73.00	6.80	6.35	0.975
Thereafter	**	**	**	**	**	0.975

(1) Edmonton Light Sweet 40 degree API, 0.3% sulphur content crude.
* Escalation varies after 2015.

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

Net Present Value of Future Production Revenue – Forecast Prices and Costs (Before Tax)

Reserves at December 31, 2010 ($ millions, discounted at)	**0%**	**5%**	**10%**	**15%**
Proved developed producing	6,370	4,230	3,222	2,635
Proved developed non-producing	158	116	90	74
Proved undeveloped	754	456	297	200
Total Proved	**7,282**	**4,802**	**3,609**	**2,909**
Probable	3,940	1,931	1,181	816
Total Proved Plus Probable Reserves	**11,222**	**6,733**	**4,790**	**3,725**

NET ASSET VALUE

Enerplus' estimated net asset value is the estimated net present value of all future net revenue from our reserves, before taxes, as estimated by our independent reserve engineers (McDaniel and Haas) at year-end. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserve engineers.

In addition, this calculation ignores "going concern" value and assumes only the reserves identified in the reserve reports with no further acquisitions or incremental development, including development of contingent resources. At December 31, 2010, the estimate of contingent resources contained within our leases was in excess of 700 million BOE, more than 2.3 times our proved plus probable reserves. As we execute our capital programs, we expect to convert contingent resources to reserves and significantly increase the value of these assets.

The land values described in the Net Asset Value table below do not necessarily reflect the full value of the contingent resources associated with these lands.

Net Asset Value (Forecast Prices and Costs at December 31, 2010)

($ millions except trust unit amounts, discounted at)	0%	5%	10%	15%
Total net present value of proved plus probable reserves (before tax)	$ 11,222	$ 6,733	$ 4,790	$ 3,725
Undeveloped acreage (2010 Year End)[(1)]				
Canada (770,000 Acres)	266	266	266	266
U.S. West (127,446 Acres)	387	387	387	387
U.S. Marcellus Shale (196,589 Acres)	565	565	565	565
Asset retirement obligations[(2)]	(238)	(129)	(29)	(10)
Long-term debt (net of cash)	(724)	(724)	(724)	(724)
Net working capital excluding deferred financial assets and credits and future income taxes	(207)	(207)	(207)	(207)
Marcellus carry commitment	(146)	(146)	(146)	(146)
Other equity investments[(3)]	155	155	155	155
Net Asset Value of Assets	**$ 11,280**	**$ 6,900**	**$ 5,057**	**$ 4,011**
Net Asset Value per Trust Unit[(4)]	**$ 63.14**	**$ 38.62**	**$ 28.31**	**$ 22.45**

(1) Acreage acquired in 2009 and 2010 valued at acquisition cost. Acreage acquired prior to 2009 valued at $100/acre.

(2) Asset retirement obligations ("ARO") do not equal the amount on the balance sheet ($208.7 million) as the balance sheet amount uses a 6.4% discount rate and a portion of the ARO costs are already reflected in the present value of reserves computed by the independent engineers.

(3) Other equity investment value based on cost, except value of Laricina equity valued based on last offering price of $30/share.

(4) Based on 178,648,000 Trust Units and equivalent Exchangeable Partnership Units outstanding as at December 31, 2010.

2010 INCOME TAX INFORMATION

Information for Canadian Residents (CDN$ per Unit)

The following table outlines the breakdown of cash distributions per unit paid or payable by Enerplus Resources Fund with respect to record dates for the period February 10 – December 31, 2010 for Canadian Income Tax purposes.

Record Date	Payment Date	Total Distribution Paid	Taxable Other Income	Taxable Eligible Dividend	Return of Capital Amount
Feb 10, 2010	Feb 20, 2010	$ 0.180000	$ 0.177732	$ 0	$ 0.002268
Mar 10, 2010	Mar 20, 2010	$ 0.180000	$ 0.177732	$ 0	$ 0.002268
Apr 10, 2010	Apr 20, 2010	$ 0.180000	$ 0.177732	$ 0	$ 0.002268
May 10, 2010	May 20, 2010	$ 0.180000	$ 0.177732	$ 0	$ 0.002268
Jun 10, 2010	Jun 20, 2010	$ 0.180000	$ 0.177732	$ 0	$ 0.002268
Jul 10, 2010	Jul 20, 2010	$ 0.180000	$ 0.177732	$ 0	$ 0.002268
Aug 10, 2010	Aug 20, 2010	$ 0.180000	$ 0.177732	$ 0	$ 0.002268
Sep 10, 2010	Sep 20, 2010	$ 0.180000	$ 0.177732	$ 0	$ 0.002268
Oct 10, 2010	Oct 20, 2010	$ 0.180000	$ 0.177732	$ 0	$ 0.002268
Nov 10, 2010	Nov 20, 2010	$ 0.180000	$ 0.177732	$ 0	$ 0.002268
Dec 10, 2010	Dec 20, 2010	$ 0.180000	$ 0.177732	$ 0	$ 0.002268
Dec 31, 2010	Jan 20, 2011	$ 0.180000	$ 0.177732	$ 0	$ 0.002268
TOTAL PER UNIT		**$ 2.160000**	**$ 2.132784**	**$ 0**	**$ 0.027216**

On January 1, 2011, Enerplus Resources Fund converted to Enerplus Corporation. Next year, Canadian shareholders can expect to receive a T5 slip on or before the last day of February 2012 for the 2011 taxation year from Enerplus Corporation.

Information for United States Residents (US$ per Unit)

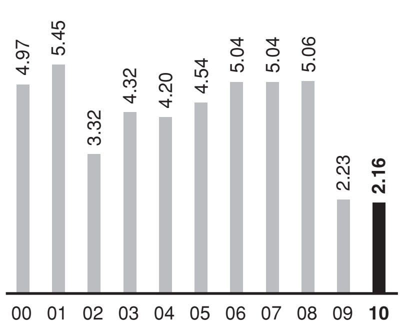
The following table outlines the breakdown of cash distributions per unit, prior to any amounts deducted for Canadian withholding tax, paid by Enerplus Resources Fund for the period January 20, 2010 to December 20, 2010 for units held through a broker or other intermediary. The amounts shown on the schedule are in U.S. dollars as converted on the applicable payment dates.

Record Date	Payment Date	Distribution Paid CDN$	Exchange Rate	Distribution Paid US$	Taxable Qualified Dividend US$	Non-Taxable Return of Capital US$
Dec 31, 2009	Jan 20, 2010	$ 0.18	0.953333	$ 0.171600	$ 0.149323	$ 0.022277
Feb 10, 2010	Feb 20, 2010	$ 0.18	0.958333	$ 0.172500	$ 0.150106	$ 0.022394
Mar 10, 2010	Mar 20, 2010	$ 0.18	0.976666	$ 0.175800	$ 0.152978	$ 0.022822
Apr 10, 2010	Apr 20, 2010	$ 0.18	0.997777	$ 0.179600	$ 0.156285	$ 0.023315
May 10, 2010	May 20, 2010	$ 0.18	0.937222	$ 0.168700	$ 0.146800	$ 0.021900
Jun 10, 2010	Jun 20, 2010	$ 0.18	0.984444	$ 0.177200	$ 0.154196	$ 0.023004
Jul 10, 2010	Jul 20, 2010	$ 0.18	0.949444	$ 0.170900	$ 0.148714	$ 0.022186
Aug 10, 2010	Aug 20, 2010	$ 0.18	0.953288	$ 0.171592	$ 0.149316	$ 0.022276
Sep 10, 2010	Sep 20, 2010	$ 0.18	0.972380	$ 0.175028	$ 0.152306	$ 0.022722
Oct 10, 2010	Oct 20, 2010	$ 0.18	0.971056	$ 0.174790	$ 0.152099	$ 0.022691
Nov 10, 2010	Nov 20, 2010	$ 0.18	0.980000	$ 0.176400	$ 0.153500	$ 0.022900
Dec 10, 2010	Dec 20, 2010	$ 0.18	0.980000	$ 0.176400	$ 0.153500	$ 0.022900
TOTAL PER UNIT		**$ 2.16**		**$ 2.090510**	**$ 1.819123**	**$ 0.271387**

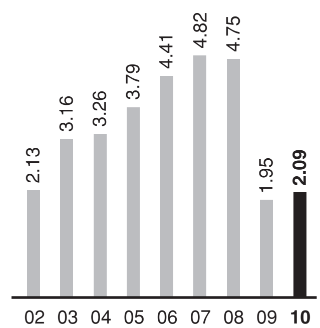
On January 1, 2011, Enerplus Resources Fund converted to Enerplus Corporation. U.S. investors in Enerplus Corporation will see no change in how dividends are to be reported due to this conversion. Enerplus expects that these dividends will continue to be treated as "Qualified Dividends".

CASH DISTRIBUTIONS PAID TO UNITHOLDERS*

Cash Distributions Paid to Unitholders – CDN$
(Cdn$/Unit)



Cash Distributions Paid to Unitholders – US$
(US$/Unit)



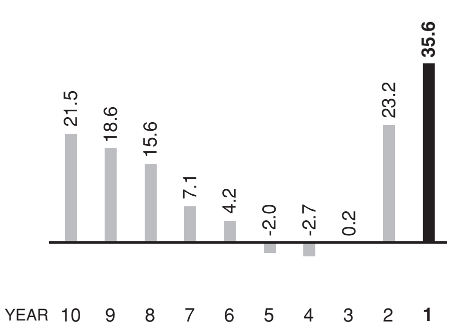
* paid January – December

Amounts paid to U.S. investors are converted to U.S. dollars on the applicable payment date. Amounts shown are prior to any amounts deducted for Canadian withholding tax. As Enerplus became listed on the NYSE in November of 2000, returns and cash distributions paid in U.S. dollars are reflected for all subsequent years only.

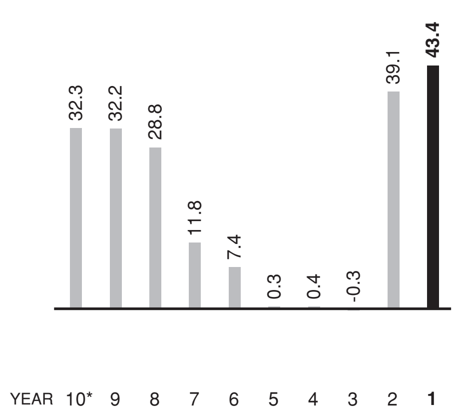
TOTAL RETURN TO UNITHOLDERS

Calculated using unit prices at December 31 plus or minus capital appreciation or depreciation and the total cash distributions paid during the period.

Total Return per year – CDN$
(January 1 – December 31)
(%)



Total return per year – US$
(January 1 – December 31)
(%)



CANADIAN 10 YEAR TRADING SUMMARY*

CDN$	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001
High	**31.85**	28.00	49.85	53.70	66.00	58.55	44.54	40.72	29.00	32.86
Low	**18.22**	16.75	21.53	38.00	43.86	40.00	32.73	25.82	22.85	22.00
Close	**30.67**	24.21	23.96	39.87	50.68	55.86	43.60	39.35	28.05	24.75
Volume (000's)	**127,386**	98,597	127,679	96,898	82,120	62,278	52,821	51,800	37,492	29,466

* Toronto Stock Exchange ("TSX") data only prior to 2010. TSX and other Canadian trading data combined for 2010.

U.S. 10 YEAR TRADING SUMMARY*

US$	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001
High	**31.83**	25.13	50.63	50.75	59.45	50.29	36.44	31.20	19.09	23.50
Low	**13.76**	12.85	17.07	38.06	38.47	32.00	23.61	17.05	14.30	13.79
Close	**30.84**	22.96	19.58	40.05	43.61	47.98	36.31	30.44	17.75	15.56
Volume (000's)	**168,979**	191,405	235,270	121,348	139,094	114,449	109,919	88,527	39,431	22,823

* New York Stock Exchange ("NYSE") data only prior to 2008. NYSE and other U.S. trading data combined for 2009 and thereafter.

DIVIDEND REINVESTMENT PLAN

Enerplus Corporation offers a convenient method for Canadian residents to reinvest cash dividends with the Dividend Reinvestment Plan.

Benefits of the Plan include:

- Existing shareholders can purchase new shares each month by automatically reinvesting cash dividends.
- Participants receive a 5% discount off the purchase price when reinvesting cash dividends.
- No commissions, service charges or brokerage fees are payable in conjunction with the Plan.

Shares held through a broker, investment dealer or other financial intermediary can participate in the Plan. Contact your broker or advisor and direct them to enroll your shares into the Plan.

To obtain more information, please contact our Investor Relations Department at 1 (800) 319-6462, in Calgary at (403) 298-2200; by fax at (403) 298-2211; or by email at investorrelations@enerplus.com. Information on the Plan is also available on our website at www.enerplus.com.

ABBREVIATIONS AND DEFINITIONS

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

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

COGPE Canadian oil and gas property expense

CTA cumulative translation adjustment

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

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent

Mcf thousand cubic feet

Mcfe thousand cubic feet equivalent

Mcf/day thousand cubic feet per day

Mcfe/day thousand cubic feet equivalent per day

MMbbl(s) million barrels

MMBOE million barrels of oil equivalent

MMBtu million British Thermal Units

MMBtu/day million British Thermal Units per day

MMcf million cubic feet

MMcf/day million cubic feet per day

MWh megawatt hour(s) of electricity

NGLs natural gas liquids

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

OCI other comprehensive income

P+P Reserves proved plus probable reserves

PDP Reserves proved developed producing reserves

RLI reserve life index

WI percentage working interest ownership

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

DEFINITIONS

Adjusted Payout Ratio Calculated as the sum of cash dividends to shareholders plus development capital and office expenditures divided by cash flow from operating activities.

Best estimate of contingent resources An estimate with an equal likelihood that the actual remaining quantities of contingent resources recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least 50% probability that the quantities actually recovered will equal or exceed the best estimate.

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

Contingent resources Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Continent resources are not, and should not be confused with, oil and gas reserves.

F&D Costs Finding and development costs. Calculated as total capital expenditures, exclusive of acquisitions or divestments, and including changes in future development capital, divided by the applicable reserve additions (proved and/or proved plus probable). It is a measure of the effectiveness of a company's capital program.

FD&A Costs Finding, development and acquisition costs. Calculated as total capital expenditures and net acquisitions, including changes in future development capital, divided by reserve additions (proved and/or proved plus probable). It is a measure of a company's ability to add reserves in a cost effective manner.

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

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

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

Oil, light & medium Oil that has a density of 22.3 degrees API or higher.

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

Payout Ratio Calculated as cash dividends to shareholders divided by cash flow from operating activities.

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

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

Resource Play Large, aerially extensive accumulations of discovered oil and natural gas with limited geological risk. Resource plays typically cover large geographic areas and require many wells to develop the play over time. With a large number of wells generating relatively predictable production and decline profiles, the timing, cost, and production rates and reserve additions associated with the resource play can be more accurately predicted.

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

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

Reserves, Company Interest Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves, but inclusive of any royalty interest reserves owned by Enerplus. Unless otherwise stated, reserve volumes utilized in any discussions or calculations are company interest reserves. "Company interest" is not a term defined in National Instrument 51-101 adopted by the Canadian Securities regulatory authorities and does not have a standardized meaning under NI 51-101 and therefore disclosure of our company interest reserves may not be comparable to disclosure of reserves by other issuers.

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

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

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

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

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

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

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

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

BOARD OF DIRECTORS

Douglas R. Martin [1, 2]
President
Charles Avenue Capital Corp.
Calgary, Alberta

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Corporate Director
Calgary, Alberta

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Corporate Director
Calgary, Alberta

Edwin V. Dodge [9, 12]
Corporate Director
Vancouver, British Columbia

Elliott Pew [7]
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Corporate Director
Calgary, Alberta

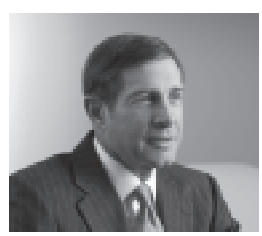
Robert B. Hodgins [3, 6]
Corporate Director
Calgary, Alberta

Glen D. Roane [5, 4]
Corporate Director
Canmore, Alberta

Clayton Woitas [7, 11]
President
Range Royalty Management Ltd.
Calgary, Alberta

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

W. C. (Mike) Seth [3, 8]
President
Seth Consultants 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 Health, Safety, Regulatory & Environment Committee
12 Chairman of the Health, Safety, Regulatory & Environment Committee

OFFICERS

Gordon J. Kerr
President &
Chief Executive Officer

Rodney D. Gray
Vice President, Finance

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

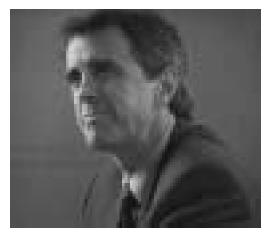
Ian C. Dundas
Executive Vice President

Dana W. Johnson
President, U.S. Operations

Robert W. Symonds
Vice President, Canadian
Operations

Robert J. Waters
Senior Vice President &
Chief Financial Officer

Robert A. Kehrig
Vice President,
Resource Development



Kenneth W. Young
Vice President, Land

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

Jennifer F. Koury
Vice President,
Corporate Services

Jodine J. Jenson Labrie
Controller, Finance

Ray J. Daniels
Vice President, Development
Services

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

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
Wells Fargo Center
1300, 1700 Lincoln Street
Denver, Colorado 80203

Telephone: 720.279.5500
Fax: 720.279.5550

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

Friday, May 13, 2011
10:00 am, MT
The Metropolitan Centre
Lecture Theatre
333 - 4th Avenue SW
Calgary, Alberta

enerPLUS

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

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