THE ENERGY OF
enerPLUS

Second Quarter Report

SIX MONTHS ENDED JUNE 30, 2010

SELECTED FINANCIAL RESULTS	Three months ended June 30,		Six months ended June 30,	
(in Canadian dollars)	2010	2009	2010	2009
Financial (000's)				
Cash Flow from Operating Activities	**$ 163,383**	$ 210,608	**$ 352,740**	$ 379,996
Cash Distributions to Unitholders[1]	**95,909**	89,610	**191,621**	179,147
Excess of Cash Flow Over Cash Distributions	**67,474**	120,998	**161,119**	200,849
Net Income	**31,296**	(3,569)	**111,299**	48,217
Debt Outstanding – net of cash	**697,817**	713,536	**697,817**	713,536
Development Capital Spending[2]	**90,538**	34,865	**185,813**	131,453
Property and Land Acquisitions[2]	**311,874**	29,113	**353,201**	33,745
Divestments	**181,238**	1,723	**182,776**	1,736
Actual Cash Distributions paid to Unitholders	**$ 0.54**	$ 0.54	**$ 1.08**	$ 1.15
Financial per Weighted Average Trust Units[3]				
Cash Flow from Operating Activities	**$ 0.92**	$ 1.27	**$ 1.99**	$ 2.29
Cash Distributions per Unit[1]	**0.54**	0.54	**1.08**	1.08
Excess of Cash Flow Over Cash Distributions	**0.38**	0.73	**0.91**	1.21
Net Income/(Loss)	**0.18**	(0.02)	**0.63**	0.29
Payout Ratio[4]	**59%**	43%	**54%**	47%
Adjusted Payout Ratio[2][4]	**115%**	60%	**107%**	83%
Selected Financial Results per BOE[5]				
Oil & Gas Sales[6]	**$ 41.18**	$ 35.60	**$ 44.39**	$ 35.42
Royalties	**(7.35)**	(6.28)	**(7.95)**	(6.36)
Commodity Derivative Instruments	**2.23**	4.95	**1.38**	5.16
Operating Costs	**(10.09)**	(9.58)	**(10.00)**	(9.77)
General and Administrative	**(1.66)**	(2.27)	**(2.06)**	(2.16)
Interest and Other Expenses	**(1.79)**	1.02	**(1.33)**	0.07
Taxes	**(0.05)**	(0.21)	**(0.03)**	(0.15)
Asset Retirement Obligations Settled	**(0.46)**	(0.29)	**(0.51)**	(0.36)
Cash Flow from Operating Activities before changes in non-cash working capital	**$ 22.01**	$ 22.94	**$ 23.89**	$ 21.85
Weighted Average Number of Trust Units Outstanding[3]	**177,526**	166,264	**177,349**	165,807
Debt to Trailing Twelve Month Cash Flow Ratio	**0.9x**	0.7x	**0.9x**	0.7x

SELECTED OPERATING RESULTS	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Average Daily Production				
Natural gas (Mcf/day)	**296,566**	338,193	**297,737**	338,538
Crude oil (bbls/day)	**31,559**	33,715	**31,268**	34,075
Natural gas liquids (bbls/day)	**3,922**	4,420	**3,924**	4,241
Total daily sales (BOE/day)	**84,909**	94,501	**84,815**	94,739
% Natural gas	**58%**	60%	**59%**	60%
Average Selling Price(6)				
Natural gas (per Mcf)	**$ 3.78**	$ 3.49	**$ 4.44**	$ 4.31
Crude oil (per bbl)	**68.72**	59.80	**71.25**	51.06
NGLs (per bbl)	**47.55**	35.47	**52.49**	37.91
CDN$/US$ exchange rate	**0.97**	0.86	**0.97**	0.83
Net Wells drilled	**19**	5	**158**	128
Success Rate(7)	**99%**	100%	**99%**	99%

(1) Calculated based on distributions paid or payable.
(2) Land acquisitions in prior periods have been reclassified from development capital expenditures to property acquisitions to conform with the current year presentation.
(3) Weighted average trust units outstanding for the period, includes the equivalent exchangeable limited partnership units.
(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" below.
(5) Non-cash amounts have been excluded.
(6) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(7) Based on wells drilled, cased and tied in.

TRUST UNIT TRADING SUMMARY

For the three months ended June 30, 2010	TSX – ERF.un (CDN$)	U.S.* – ERF (US$)
High	$ 25.07	$ 24.84
Low	$ 18.22	$ 13.76
Close	$ 22.89	$ 21.57

* U.S. Composite Exchange Data including NYSE.

2010 CASH DISTRIBUTIONS PER TRUST UNIT

Payment Month	CDN$	US$
First Quarter Total	**$ 0.54**	**$ 0.52**
April	$ 0.18	$ 0.18
May	0.18	0.17
June	0.18	0.18
Second Quarter Total	**$ 0.54**	**$ 0.53**
Total Year-to-Date	**$ 1.08**	**$ 1.05**

This interim report contains certain forward-looking information and statements. We refer you to the end of the accompanying Management's Discussion and Analysis under "Forward-Looking Information and Statements" for our disclaimer on forward-looking information and statements which applies to all other portions of this interim report. For information on the use of the term "BOE" see the introductory paragraph under the Management's Discussion and Analysis section in this interim report. All amounts in this interim report are in Canadian dollars unless otherwise specified.

PRESIDENT'S MESSAGE

Strategic Execution

I'm pleased to report that our results for the second quarter of 2010 are meeting and, in certain areas, exceeding our expectations. Production volumes are in line with expectations at just under 85,000 BOE/day and operating costs have decreased to $9.82/BOE. We have made significant progress on our divestment plans in the current year and have sold 3,400 BOE/day of non-core production for approximately $198 million. Through our acquisition activities we have added over 1,100 bbls/day of high netback Bakken crude oil production with 14,000 net acres of undeveloped land in North Dakota, over 100,000 net acres of undeveloped land in southern Saskatchewan, an additional 6,000 net acres of operated land in the Marcellus, and approximately 6,300 net acres of undeveloped land in the Deep Basin. These are all very positive results for Enerplus.

Our financial position also remains strong with a debt to cash flow ratio of 0.9x at the end of the second quarter. In June, we negotiated a new $1 billion credit facility with our syndicate of banks. Although our asset base would support a larger credit facility, we chose to reduce the size due to the significant increase in the cost of maintaining the unused credit capacity. At the end of the second quarter, we had only $170 million drawn on the facility. Along with the proceeds from additional divestment activities, this facility will provide us with significant financial flexibility to pursue our capital spending plans and acquisition opportunities.

We have made significant progress in the transformation of our asset base. We now have over 350,000 net acres of prospective lands primarily in the Marcellus shale gas play and the Bakken light oil play that will provide us with extensive growth prospects for the future. We also have a stable production base from our existing portfolio of properties that provides cash flow to support both distributions to investors and reinvestment into the asset base. We plan to continue focusing our asset base through the divestment of non-core assets and building operated positions in the Marcellus, in the Bakken in both Canada and the U.S. and the Deep Basin in western Canada. We believe this focus will improve the profitability of our business as lower margin assets are replaced with those that have higher netbacks, greater future growth potential and better economics.

Acquisitions & Divestments

On June 29, 2010, we increased our working interests in Fort Berthold, North Dakota through the acquisition of our partner's 50% working interest, adding approximately 14,000 net acres of prospective land and 1,100 BOE/day of early stage high netback crude oil production from 4 operated wells and 1 non-operated well. The total cost of the acquisition was approximately US$108 million before closing adjustments. Our undeveloped acreage position in Fort Berthold is now 25,000 net acres with a 95% working interest which we believe is prospective for both the Bakken and Three Forks formations. These lands are located primarily in the northern part of Dunn County, which has some of the best economics and performance results for Bakken production across the state. Based on our internal assessment of the Bakken potential on these lands, we believe we can drill up to 2 wells per section through a combination of long and short length lateral horizontal wells. We also believe the lands are prospective for the Three Forks formation and will be testing this potential this year. Operating netbacks are expected to average over $55/BOE based upon current commodity prices with operating costs below $5.00/BOE. We expect significant production growth from this area in the coming years.

In April we acquired 154 new sections (approximately 100,000 net acres) of undeveloped land in southern Saskatchewan at a Crown land sale for $117 million. These lands are in an emerging Bakken play area and are contiguous to our existing land holdings. We now hold a 100% working interest in approximately 142,000 acres in the Freda Lake/Neptune/Oungre area. To date we have drilled 4 wells on these lands and are evaluating results with an expectation that we will drill a number of wells in the second half of 2010 to delineate the play. In aggregate we hold over 170,000 net acres of undeveloped land in the Bakken/tight oil areas of Saskatchewan, North Dakota and Manitoba which are in the early stages of development.

On June 30, 2010, we also executed our first non-core asset divestment. Approximately 3,400 BOE/day (90% crude oil) and approximately 13 million BOE of proved plus probable reserves were sold for $198 million before adjustments representing sale metrics of approximately $58,000 per flowing BOE of production and $22.83/BOE of proved plus probable reserves including future development costs. This production was located in central and northern Alberta and comprised of varied working interests in 14 properties. The average operating netback of these properties was approximately $27.00/BOE with operating costs of approximately $17.00/BOE.

These transactions represent significant progress in our strategy to better focus our efforts on properties that have greater development potential and superior operating metrics. We are continuing to market assets that do not fit our strategy and expect to sell additional properties in 2010 and beyond. We are also considering various alternatives relating to our Kirby oil sands interest given our desire to focus on plays that offer scope and scale with nearer-term cash flow. We will provide an update as developments occur.

Updating 2010 Guidance

Given the recent acquisition and divestment activity and the capital opportunities associated with the new Bakken lands in Saskatchewan, North Dakota and our Marcellus shale gas play, we are adjusting our 2010 operating guidance. Annual production volumes are now expected to average 85,000 BOE/day versus our original estimate of 86,000 BOE/day with exit rates of 86,000 BOE/day versus our original estimate of 88,000 BOE/day. We plan to increase our capital spending by $60 million to $485 million with the majority of the increase on light oil projects that are highly economic in the current commodity price environment. As this incremental capital spending is occurring late in 2010, we expect to see a greater impact on production volumes in 2011. Total expenditures on oil projects are now expected to be 63% of our total development capital budget. In addition, we are reducing our operating cost guidance given our lower realized costs year-to-date and the elimination of higher cost properties associated with our divestment. We now anticipate operating costs to average $10.20/BOE for 2010. Please see our Management's Discussion and Analysis for further detail on changes to our 2010 guidance.

The following table reconciles our original 2010 production guidance to our revised guidance taking into consideration the impacts of our acquisition and divestment activity as well as our increased capital spending guidance:

(BOE/day)	Annual Average	Exit Rate
Original Guidance	86,000	88,000
Effect of Asset Dispositions	(1,700)	(3,100)
Sub-Total	84,300	84,900
Incremental production relating to acquisitions & capital spending	700	1,100
Revised Guidance	85,000	86,000

Operational Results

Our oil and gas production averaged 84,909 BOE/day in the second quarter, slightly higher than the first quarter of this year and on track with our expectations. Our operations generated cash flow of $163 million during the quarter ($0.92/unit) down 14% from the first quarter of 2010 due to lower commodity prices. Approximately 59% of cash flow was distributed to Unitholders through monthly distributions of $0.18/unit. Distributions and development capital spending combined resulted in an adjusted payout ratio of 115%.

Development capital spending and drilling activity slowed considerably in the second quarter due to spring breakup and excessively wet conditions throughout much of Saskatchewan and southern Alberta. We drilled a total of 19 net wells in the quarter including 4 net wells in the Marcellus and another 6 net wells in our Bakken/tight oil resource play. We invested approximately $91 million of development capital (44% natural gas, 56% oil) of which approximately 60% was spent in our Marcellus shale gas and Bakken tight oil plays.

Production and Capital Spending Summary

Play Type	Three months ended June 30, 2010 Average Production Volumes	Three months ended June 30, 2010 Capital Spending ($ millions)	Six months ended June 30, 2010 Average Production Volumes	Six months ended June 30, 2010 Capital Spending ($ millions)
Bakken/Tight Oil (BOE/day)	10,260	32	9,547	63
Crude Oil Waterfloods (BOE/day)	15,762	16	15,863	36
Conventional Oil (BOE/day)	9,066	3	9,600	6
Total Oil (BOE/day)	**35,088**	**51**	**35,010**	**105**
Marcellus Shale Gas (Mcfe/day)	6,351	21	4,523	35
Shallow Gas (Mcfe/day)	122,710	3	124,581	10
Tight Gas (Mcfe/day)	87,371	8	88,569	22
Conventional Gas (Mcfe/day)	82,496	8	81,160	14
Total Gas (Mcfe/day)	**298,928**	**40**	**298,833**	**81**
Company Total	**84,909**	**91**	**84,815**	**186**

Drilling Activity (net wells), for the three months ended June 30, 2010

Play Type	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in	Wells On-stream	Dry & Abandoned Wells	Drilling Success Rate
Bakken/Tight Oil	6.5	–	6.5	4.8	1.7	–	100%
Crude Oil Waterfloods	1.2	0.3	1.5	0.8	0.7	–	100%
Conventional Oil	4.4	–	4.4	4.4	–	–	100%
Total Oil	**12.1**	**0.3**	**12.4**	**10.0**	**2.4**	**–**	**100%**
Marcellus Shale Gas	3.1	0.8	3.9	3.9	–	0.1	99%
Shallow Gas	–	–	–	–	–	–	100%
Tight Gas	0.1	2.0	2.1	2.1	–	–	100%
Conventional Gas	–	0.1	0.1	0.1	–	–	100%
Total Gas	**3.2**	**2.9**	**6.1**	**6.1**	**–**	**0.1**	**99%**
Company Total	**15.3**	**3.2**	**18.5**	**16.1**	**2.4**	**0.1**	**99%**

Marcellus

Production in our Marcellus shale gas play averaged 6.4 MMcf/day in the second quarter, up from 2.7 MMcf/day during the first quarter. We spent approximately $21 million in development capital and drilled 21 gross wells (4 net wells). In addition, 15 gross wells were completed and another 7 wells were tied in. The bulk of the drilling activity was focused in Bradford, Lycoming, and Susquehanna counties in Pennsylvania as well as Marshall County in West Virginia. We currently have 6 rigs running in this play and may add a 7th during the fourth quarter. Current production from the Marcellus is over 9 MMcf/day.

We have increased the number of frac stages on our most recent horizontal wells from an average of 8 stages per well to 10 to 15 stages per well depending on lateral length. 24 hour test rates on the 7 wells completed and tied in during the quarter averaged 4.3 MMcf/day per well, 3 of which have averaged 5.7 MMcf/day. Our highest 24 hour test rate was 14 MMcf/day on a well awaiting tie-in in Greene County, PA. Given the longer lateral lengths and increased number of frac stages, we have seen an improvement in 24 hour test rates such that the 10 well moving average over the last 9 months has gone from 3.5 MMcf/day to over 5 MMcf/day. Overall, we are encouraged with the performance of the wells brought on-stream to date. In addition to improving well productivity, we are seeing lower than expected decline rates in a majority of areas.

The table below provides additional detail on the majority of our producing horizontal wells. Of note, production from Marshall County which has associated natural gas liquids is currently restricted due to processing limitations in the area. We expect this issue to be resolved in the coming months. In Lycoming County, the average 30 day production rate does not include the most recent 4 wells on production as we do not have 30 days of production data. However the average 24 hour peak rate on these wells is 4.5 MMcf/day.

County	# of HZ Wells	Avg. Lateral Length(ft)	Avg. # of Fracs	Avg. 30 Producing Day Gross IP (Mcf/day)
Bradford	2	2,241	7	2,556
Lycoming	9	2,950	8	3,028
Marshall	6	2,765	8	2,527
Susquehanna	2	2,715	9	6,484

28 gross wells are currently on production in our Marcellus play (23 horizontal wells and 5 vertical wells), with an additional 39 wells waiting on completion and 11 wells waiting on pipeline. Completion activity remains challenging due to the limited availability of frac and cementing crews in the region, however we expect these conditions may ease somewhat heading into the winter drilling season as indications are that more crews and equipment are being added into this region by suppliers. Given the favourable summer weather, our midstream partners expect to make substantial progress in building the gas gathering infrastructure necessary to bring more of these wells on stream.

We continued to add to our Marcellus position during the quarter with the acquisition of over 6,000 net acres and now hold approximately 12,000 net acres of operated land in Center and Clinton counties. Current plans include shooting seismic in the area and we expect to drill our first operated well later this year. Full year 2010 capital spending plans have been increased by $10 million to $90 million, excluding our carry commitment of $64 million.

Bakken/Tight Oil

Production in our Bakken/tight oil resource play averaged approximately 10,260 BOE/day during the quarter, representing a 16% increase from the first quarter of 2010. We spent approximately $32 million drilling 6 net wells primarily in our Montana and North Dakota assets. Activity in southeast Saskatchewan was limited due to extremely wet weather and a longer than planned spring breakup.

We drilled 3.5 net horizontal wells in the Sleeping Giant field in Montana and tied in 4 wells. We've changed our completion techniques and the 30 day production rates on these wells are significantly better than our original type curve estimates. Initial production rates are 75% higher with an incremental cost of only 20%. The cost of the new wells are ranging from $4.5 million to $5.3 million depending upon the lateral length. Although the field is at a relatively advanced state of primary development, there are still a modest number of drilling locations remaining in addition to refrac and recompletion opportunities which we are evaluating.

One well was drilled at Fort Berthold, North Dakota during the quarter with 4 additional wells brought on stream. 30 day initial production rates for each of the 4 wells on stream have averaged approximately 800 bbls/day per well excluding any associated natural gas which is not being captured at this time. We are currently in the process of drilling and completing another 3 wells.

Sleeping Giant, MT	Lateral Length(ft)	# of Frac Stages	30 day Gross IP Rates* (BOE/day)	Average Working Interest
Well #1	3,750	8	326	81%
Well #2	5,750	10	272	81%
Well #3**	9,250	18	984	69%
Well #4**	9,500	18	949	69%

Ft. Berthold, ND			30 day IP Rates (bbls/day)	
Well #1	4,300	12	621	100%
Well #2	4,300	12	775	100%
Well #3	4,300	12	885	100%
Well #4	4,300	12	910	100%

* Sleeping Giant volumes include both crude oil and natural gas. Natural gas volumes are not being captured at Fort Berthold at this time.

** Wells 3 and 4 were put on pump immediately following completion to enhance initial production whereas the first 2 wells were initially flowed without pump.

We have allocated additional capital to our Bakken/tight oil resource play, and now expect to invest over $170 million of our $485 million capital budget in this play in 2010. This additional capital will be spent on drilling 10 to 14 assessment wells on our Bakken lands at Freda Lake, Neptune and Oungre in Saskatchewan plus increased activity at Fort Berthold due to the additional interests acquired in late June. We expect to have up to 3 rigs running in Saskatchewan with 1 rig operating in North Dakota in the second half of the year. We expect this additional capital to add approximately 2,200 bbls/day of initial production, the majority of which will be realized in the first quarter of 2011.

We are excited by the opportunities that our investments in the Marcellus, Bakken/tight oil and Deep Basin plays present to us. We are becoming more focused on key plays in our portfolio and will continue our non-core asset disposition program. Our financial strength remains a competitive advantage for us as well. We are expecting to convert into a dividend paying company on January 1, 2011 assuming Unitholder approval and do not anticipate this will be a taxable event for our Unitholders. It is our intention to maintain our monthly distributions to Unitholders at current levels through the conversion assuming current commodity prices prevail. We are committed to providing a strong total return comprised of both growth and income to our investors and are well on our way to meeting this commitment.

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Resources Fund

The following discussion and analysis of financial results is dated August 5, 2010 and is to be read in conjunction with:

- the audited consolidated financial statements as at and for the years ended December 31, 2009 and 2008 and accompanying management's discussion and analysis; and
- the unaudited interim consolidated financial statements as at and for the three and six months ended June 30, 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 accompanying unaudited interim 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.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for our disclaimer.

NON-GAAP MEASURES

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

During the second quarter we continued to make progress on high grading our asset base along with meeting our operational expectations. We had significant acquisition and disposition activity with $311.9 million of property and land acquisitions along with $181.3 million of property dispositions during the quarter. Production and development capital spending were on target while operating expenses were better than expected primarily due to savings from shorter plant turnaround time and less workover activity. Despite this, cash flow decreased to $163.4 million from $189.4 million in the first quarter of 2010 largely due to lower realized commodity prices.

We are revising our annual production, development capital spending and operating cost guidance primarily as a result of our acquisition and disposition activity, and currently expect annual average production of 85,000 BOE/day (from 86,000 BOE/day) and an exit rate of 86,000 BOE/day (from 88,000 BOE/day). Development capital spending guidance is being increased to $485 million (from $425 million) and operating costs are being revised downwards to $10.20/BOE (from $10.90/BOE).

During the quarter we also extended our unsecured, covenant-based bank credit facility for a three year term, maturing June 30, 2013.

ACQUISITIONS AND DISPOSITIONS

During the second quarter property and land acquisitions totaled $311.9 million with the acquisition of additional interests in earlier stage growth assets. These transactions included assets in the Saskatchewan and North Dakota Bakken oil plays, the Marcellus shale natural gas play and the British Columbia Deep Basin natural gas play. In April we acquired approximately 100,000 net acres of prospective crown land contiguous to our existing holdings in the Freda Lake, Neptune and Oungre areas of the Saskatchewan Bakken for $117.0 million. On June 29, 2010 we purchased our operating partner's interest in our Fort Berthold, North Dakota Bakken asset acquiring an incremental 14,000 net acres and 1,100 BOE/day of production for US$112.8 million including closing adjustments. We continued to expand our presence in the Marcellus shale play during the quarter as we acquired approximately 6,000 net acres of operated land for US$28.7 million. We also acquired approximately 6,300 net acres of undeveloped land in the British Columbia Deep Basin for $15.1 million.

As a result of the acquisitions we are anticipating additional development capital spending of approximately $60.0 million during the remainder of 2010, invested primarily on the assets recently acquired. Given the anticipated timing of the spending we are not expecting this activity to have a material impact on our 2010 production or operating results.

Property dispositions during the second quarter related to the first package of our planned divestment of non-core conventional assets. This package successfully closed on June 30, 2010 for proceeds of $197.8 million before adjustments of approximately $16 million. The properties divested were primarily in Alberta with current production of approximately 3,400 BOE/day (90% crude oil). The loss of production for the remaining six months of the year will impact our annual average production by approximately 1,700 BOE/day.

We are marketing additional divestment packages with production of approximately 9,000 BOE/day and expect that a portion of this production may be sold during the remainder of the year. We are also continuing to explore strategic alternatives for our Kirby oil sands asset.

RESULTS OF OPERATIONS

Production

Production in the second quarter was in line with our expectations at 84,909 BOE/day, slightly above our first quarter production of 84,719 BOE/day and 10% lower than production of 94,501 BOE/day in the second quarter of 2009. The 10% reduction was primarily a result of our decreased development capital program during 2009 which resulted in declining production levels throughout 2009 and into 2010.

Average production volumes for the three and six months ended June 30, 2010 and 2009 are outlined below:

	Three months ended June 30,			Six months ended June 30,		
Daily Production Volumes	**2010**	**2009**	**% Change**	**2010**	**2009**	**% Change**
Natural gas (Mcf/day)	**296,566**	338,193	(12)%	**297,737**	338,538	(12)%
Crude oil (bbls/day)	**31,559**	33,715	(6)%	**31,268**	34,075	(8)%
Natural gas liquids (bbls/day)	**3,922**	4,420	(11)%	**3,924**	4,241	(7)%
Total daily sales (BOE/day)	**84,909**	94,501	(10)%	**84,815**	94,739	(10)%

We are revising our annual average and exit rate production guidance to 85,000 BOE/day and 86,000 BOE/day, respectively, down from 86,000 BOE/day and 88,000 BOE/day. This change in guidance reflects the downward impact of our June 30, 2010 non-core asset disposition partially offset by additional production resulting from our Fort Berthold acquisition. This revised guidance does not contemplate any additional acquisition or divestment activity during the remainder of 2010.

Pricing

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 the three and six months ended June 30, 2010 and 2009. It also compares the benchmark price indices for the same periods.

	Three months ended June 30,			Six months ended June 30,		
Average Selling Price[1]	**2010**	**2009**	**% Change**	**2010**	**2009**	**% Change**
Natural gas (per Mcf)	**$ 3.78**	$ 3.49	8%	**$ 4.44**	$ 4.31	3%
Crude oil (per bbl)	**$ 68.72**	$ 59.80	15%	**$ 71.25**	$ 51.06	40%
Natural gas liquids (per bbl)	**$ 47.55**	$ 35.47	34%	**$ 52.49**	$ 37.91	39%
Per BOE	**$ 41.18**	$ 35.60	16%	**$ 44.39**	$ 35.42	25%

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

Average Benchmark Pricing	Three months ended June 30, 2010	2009	% Change	Six months ended June 30, 2010	2009	% Change
AECO natural gas – monthly index (CDN$/Mcf)	**$ 3.86**	$ 3.66	6%	**$ 4.61**	$ 4.65	(1)%
AECO natural gas – daily index (CDN$/Mcf)	**$ 3.90**	$ 3.45	13%	**$ 4.42**	$ 4.18	6%
NYMEX natural gas – monthly index (US$/Mcf)	**$ 4.07**	$ 3.60	13%	**$ 4.73**	$ 4.19	13%
NYMEX natural gas – monthly index CDN$ equivalent (CDN$/Mcf)	**$ 4.20**	$ 4.19	0%	**$ 4.88**	$ 5.05	(3)%
WTI crude oil (US$/bbl)	**$ 78.03**	$ 59.62	31%	**$ 78.37**	$ 51.35	53%
WTI crude oil: CDN$ equivalent (CDN$/bbl)	**$ 80.44**	$ 69.33	16%	**$ 80.79**	$ 61.87	31%
CDN$/US$ exchange rate	**0.97**	0.86	13%	**0.97**	0.83	17%

During the second quarter of 2010 the average of the AECO monthly and daily natural gas indices declined 25% from $5.16/Mcf in the first quarter to $3.88/Mcf in the second quarter. Weak demand during the second quarter combined with high natural gas storage inventories and increasing rig counts have put downward pressure on prices.

We realized an average price on our natural gas of $3.78/Mcf (net of transportation costs) during the second quarter of 2010, an increase of 8% from $3.49/Mcf for the same period in 2009. For the six months ended June 30, 2010 we realized an average price of $4.44/Mcf, a 3% increase from the same period in 2009. The majority of our natural gas sales are priced with reference to either the monthly or daily AECO indices. The changes experienced in our realized prices are comparable to the indices for the three and six months ended June 30, 2010.

Enerplus' average realized crude oil sales price was $68.72/bbl (net of transportation costs) for the second quarter, a 15% increase from $59.80/bbl during the same period in 2009. WTI crude oil prices averaged US$78.03/bbl for the second quarter in 2010, a 31% increase compared to US$59.62/bbl for the same period in 2009. In Canadian dollars WTI increased 16% to $80.44/bbl from $69.33/bbl for the same period in 2009. Generally, due to our crude oil sales mix, we expect the change in our realized price to fall between the change in the U.S. and Canadian dollar equivalent WTI. Our second quarter realized price did not increase as much as the WTI benchmark expressed both in Canadian and U.S. dollars due to differentials widening during the second quarter of 2010 compared to the same period in 2009. Differentials increased due to refinery outages and pipeline issues. For the six months ended June 30, 2010 our realized crude oil sales price was $71.25/bbl (net of transportation costs), a 40% increase from $51.06/bbl during the same period in 2009. The increase in our realized price for the six months ended June 30, 2010 is comparable to the changes experienced with the benchmark price for crude oil.

The Canadian dollar continued to strengthen against the U.S. dollar during the second quarter and was significantly stronger for the three and six months ended June 30, 2010 compared to the same periods in 2009. As most of our crude oil and natural gas is priced in reference to U.S. dollar denominated benchmarks, this movement in the exchange rate decreased the Canadian dollar prices that we would have otherwise realized.

Price Risk Management

We continue to monitor 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.

Our existing financial derivative contracts are designed to protect a portion of our natural gas sales through March 2011 and a portion of our crude oil sales through December 2011. In particular for 2010 we have sought more certainty in our cash flow to support our growth activities. See Note 8 for a detailed list of our current price risk management positions.

The following is a summary of the financial contracts in place at July 28, 2010 expressed as a percentage of our anticipated net production volumes:

	Natural Gas (CDN$/Mcf)			Crude Oil (US$/bbl)	
	July 1, 2010 – October 31, 2010	November 1, 2010 – December 31, 2010	January 1, 2011 – March 31, 2011	July 1, 2010 – December 31, 2010	January 1, 2011 – December 31, 2011
Purchased Puts (floor prices)	$ 5.52	$ 5.52	–	–	–
%	10%	10%	–	–	–
Sold Puts (limiting downside protection)	$ 4.01	$ 4.17	$ 4.29	$ 47.50	$ 56.20
%	10%	22%	18%	19%	8%
Swaps (fixed price)	$ 6.48	$ 6.39	$ 6.39	$ 78.32	$ 88.47
%	31%	28%	28%	52%	16%
Purchased Calls (repurchasing upside)	$ 6.54	$ 6.96	$ 6.77	$ 92.68	$ 103.00
%	4%	12%	18%	27%	8%

Based on weighted average price (before premiums), estimated 2010 average annual production of 85,000 BOE/day, net of royalties and assuming an 18% royalty rate.

We have existing electricity derivative contracts in place for the periods July 2010 through December 2012 to protect a portion of our Alberta operated power consumption. For the remainder of 2010 approximately 73% of our Alberta operated power is hedged at $61.69/Mwh. For 2011 approximately 60% is hedged at $55.84/Mwh and for 2012 approximately 13% is hedged at $54.50/Mwh. See Note 8 for further details.

Accounting for Price Risk Management

During the second quarter of 2010 our price risk management program generated cash gains of $19.8 million on our natural gas contracts and cash losses of $2.5 million on our crude oil contracts. In comparison, during the second quarter of 2009 we experienced cash gains of $20.6 million and $22.0 million respectively. For the six months ended June 30, 2010 we experienced cash gains of $27.8 million on our natural gas contracts and cash losses of $6.6 million on our crude oil contracts, compared to cash gains of $34.9 million and $53.6 million respectively, for the same period in 2009. The natural gas cash gains in 2010 are due to contracts which provided floor protection above market prices. The crude oil cash losses are the 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 a non-cash charge or a non-cash gain to earnings. At June 30, 2010 the fair value of our natural gas and crude oil derivative instruments, net of premiums, represented gains of $32.5 million and $12.5 million respectively. These gains are recorded as current deferred financial assets on our balance sheet. In comparison, at March 31, 2010 the fair value of our natural gas and crude oil derivative instruments represented gains of $56.3 million and losses of $26.9 million respectively. The change in the fair value of our commodity derivative instruments between the first and second quarter of 2010 resulted in an unrealized loss of $23.8 million for natural gas and an unrealized gain of $39.4 million for crude oil. For the six months ended June 30, 2010 the change in fair value of our commodity derivative instruments resulted in unrealized gains of $12.1 million and $32.9 million for natural gas and crude oil respectively. See Note 8 for details.

The following table summarizes the effects of our financial contracts on income:

Risk Management Costs ($ millions, except per unit amounts)	**Three months ended June 30, 2010**		**Three months ended June 30, 2009**	
Cash gains/(losses):				
Natural gas	**$ 19.8**	**$ 0.73/Mcf**	$ 20.6	$ 0.67/Mcf
Crude oil	**(2.5)**	**$ (0.87)/bbl**	22.0	$ 7.16/bbl
Total cash gains/(losses)	**$ 17.3**	**$ 2.23/BOE**	$ 42.6	$ 4.95/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – natural gas	**$ (23.8)**	**$ (0.88)/Mcf**	$ (9.7)	$ (0.31)/Mcf
Change in fair value – crude oil	**39.4**	**$ 13.72/bbl**	(40.2)	$ (13.11)/bbl
Total non-cash gains/(losses)	**$ 15.6**	**$ 2.02/BOE**	$ (49.9)	$ (5.80)/BOE
Total gains/(losses)	**$ 32.9**	**$ 4.25/BOE**	$ (7.3)	$ (0.85)/BOE

Risk Management Costs ($ millions, except per unit amounts)	**Six months ended June 30, 2010**		**Six months ended June 30, 2009**	
Cash gains/(losses):				
Natural gas	**$ 27.8**	**$ 0.52/Mcf**	$ 34.9	$ 0.57/Mcf
Crude oil	**(6.6)**	**$ (1.17)/bbl**	53.6	$ 8.69/bbl
Total cash gains/(losses)	**$ 21.2**	**$ 1.38/BOE**	$ 88.5	$ 5.16/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – natural gas	**$ 12.1**	**$ 0.22/Mcf**	$ 23.3	$ 0.38/Mcf
Change in fair value – crude oil	**32.9**	**$ 5.81/bbl**	(60.5)	$ (9.82)/bbl
Total non-cash gains/(losses)	**$ 45.0**	**$ 2.93/BOE**	$ (37.2)	$ (2.17)/BOE
Total gains/(losses)	**$ 66.2**	**$ 4.31/BOE**	$ 51.3	$ 2.99/BOE

Revenues

Crude oil and natural gas revenues were lower during the second quarter of 2010 compared to the first quarter of 2010 primarily due to the decline in natural gas prices.

Crude oil and natural gas revenues for the three months ended June 30, 2010 were $318.2 million ($325.2 million, net of $7.0 million transportation costs) compared to $306.2 million ($312.5 million, net of $6.3 million transportation costs) for the same period in 2009. For the six months ended June 30, 2010 revenues were $681.5 million ($694.8 million, net of $13.3 million transportation costs) compared to $607.4 million ($620.1 million, net of $12.7 million transportation costs) during the same period in 2009. The increase in revenues in 2010 was primarily due to higher crude oil prices and to a lesser extent natural gas and natural gas liquid prices, partially offset by lower production.

The following table summarizes the changes in sales revenue:

Analysis of Sales Revenue[1] ($ millions)		**Crude Oil**		**NGLs**		**Natural Gas**		**Total**
Quarter ended June 30, 2009	$	183.5	$	14.3	$	108.4	$	306.2
Price variance[1]		25.6		4.3		8.1		38.0
Volume variance		(11.7)		(1.6)		(12.7)		(26.0)
Quarter ended June 30, 2010	**$**	**197.4**	**$**	**17.0**	**$**	**103.8**	**$**	**318.2**

($ millions)		**Crude Oil**		**NGLs**		**Natural Gas**		**Total**
Year-to-date June 30, 2009	$	314.9	$	29.1	$	263.4	$	607.4
Price variance[1]		114.4		10.4		7.0		131.8
Volume variance		(26.0)		(2.2)		(29.5)		(57.7)
Year-to-date June 30, 2010	**$**	**403.3**	**$**	**37.3**	**$**	**240.9**	**$**	**681.5**

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

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three and six months ended June 30, 2010 royalties were $56.8 million and $122.2 million respectively, compared to $54.0 million and $109.0 million for the same periods of 2009. The royalty rate experienced for both 2010 and 2009 was 18%, calculated as a percentage of oil and gas sales, net of transportation costs.

Based on our year to date results we now expect royalties to average 18% for 2010, calculated as a percentage of oil and gas sales, net of transportation costs.

Operating Expenses

Operating expenses were unchanged at $75.9 million during the first and second quarters of 2010. However, on a BOE basis operating costs decreased to $9.82/BOE from $9.96/BOE due to a slight increase in production quarter over quarter. Excluding non-cash gains on our electricity contracts operating costs were $10.09/BOE during the second quarter.

For the second quarter of 2010 operating expenses were $75.9 million or $9.82/BOE compared to $85.4 million or $9.93/BOE for the second quarter of 2009. For the six months ended June 30, 2010 operating expenses were $151.8 million or $9.89/BOE compared to $169.5 million or $9.89/BOE for the same period in 2009. Operating costs on a total dollar basis have decreased in 2010 due to cost savings realized from more efficient plant turnarounds along with lower well service costs resulting from less workover activity.

We are decreasing our annual operating cost guidance to $10.20/BOE from $10.90/BOE reflecting lower year-to-date costs and the impact of the recent non-core asset disposition which included higher operating cost properties.

General and Administrative Expenses ("G&A")

G&A expenses for the three months ended June 30, 2010 were $14.6 million or $1.89/BOE compared to $21.4 million or $2.49/BOE for the second quarter of 2009. G&A expenses totaled $34.2 million or $2.23/BOE for the six months ended June 30, 2010 compared to $40.3 million or $2.35/BOE for the same period in 2009. The decrease was due to lower staff levels in 2010 and adjustments related to prior period lease costs and reduced estimates associated with our long-term incentive plans. In addition, 2009 G&A included $2.3 million of transaction costs related to our senior notes offering.

Non-cash G&A charges for the three and six months ended June 30, 2010 included non-cash charges of $1.8 million or $0.23/BOE and $2.5 million or $0.17/BOE respectively, compared to $1.9 million or $0.22/BOE and $3.3 million or $0.19/BOE for the same periods in 2009. These amounts relate solely to our trust unit rights incentive plan and are determined using a binomial lattice option-pricing model. See Note 7 for further details.

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

General and Administrative Costs ($ millions)	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Cash	**$ 12.7**	$ 19.5	**$ 31.2**	$ 37.0
Corporate conversion costs	**0.1**	–	**0.5**	–
Trust unit rights incentive plan (non-cash)	**1.8**	1.9	**2.5**	3.3
Total G&A	**$ 14.6**	$ 21.4	**$ 34.2**	$ 40.3

(Per BOE)	2010	2009	2010	2009
Cash	**$ 1.65**	$ 2.27	**$ 2.03**	$ 2.16
Corporate conversion costs	**0.01**	–	**0.03**	–
Trust unit rights incentive plan (non-cash)	**0.23**	0.22	**0.17**	0.19
Total G&A	**$ 1.89**	$ 2.49	**$ 2.23**	$ 2.35

We continue to expect annual G&A costs to be $2.45/BOE including non-cash costs of $0.20/BOE. In addition we expect corporate conversion costs to be approximately $0.10/BOE.

Interest Expense

Interest expense includes interest on debt, bank charges, 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 5 for further details.

Interest on debt totaled $15.0 million and $24.2 million for the three and six months ended June 30, 2010, compared to $5.2 million and $10.8 million respectively, for the same periods in 2009. This increase in 2010 was a result of our new senior unsecured notes issued in June 2009 along with a bank fee of $5.0 million recorded in June 2010 relating to the three year extension of our credit facility.

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. We recorded a non-cash interest loss of $0.7 million for the three months ended June 30, 2010 and a non-cash gain of $1.0 million for the six months ended June 30, 2010, compared to non-cash interest losses of $16.4 million and $22.8 million for the same periods in 2009.

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

Interest Expense ($ millions)	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Interest on debt	**$ 15.0**	$ 5.2	**$ 24.2**	$ 10.8
Non-cash interest loss/(gain)	**0.7**	16.4	**(1.0)**	22.8
Total Interest Expense	**$ 15.7**	$ 21.6	**$ 23.2**	$ 33.6

Approximately 65% of our debt was based on fixed interest rates while 35% had floating interest rates at June 30, 2010.

Foreign Exchange

For the three and six months ended June 30, 2010 we recorded foreign exchange losses of $13.6 million and $3.2 million respectively, compared to gains of $12.6 million and $11.8 million for the same periods during 2009. On June 19, 2010 we made the first US$35.0 million principal repayment on our US$175.0 million senior notes. The repayment resulted in both a realized foreign exchange loss and an unrealized foreign exchange gain of approximately $18.0 million as a result of the underlying CCIRS which effectively fixed the principal repayment at a foreign exchange rate of $0.6522 CDN$/US$. See Note 6 for further details.

Capital Expenditures

Development capital spending during the three and six months ended June 30, 2010 was in line with expectations at $90.5 million (net of $1 million "Drilling Royalty Credits" (DRC)) and $185.8 million (net of $21 million DRC) respectively, compared to $34.9 million and $131.5 million during the same periods in 2009. Activity during the quarter was focused on our Bakken/tight oil and crude oil waterflood resource plays as well as development of our Marcellus shale gas play in the U.S.

Property and land acquisitions for the three and six months ended June 30, 2010 totaled $311.9 million and $353.2 million respectively, compared to $29.1 million and $33.7 million for the same periods in 2009. Spending during the quarter focused primarily on our earlier stage growth assets with further investment in our Bakken oil play areas in Saskatchewan and North Dakota, the Marcellus shale natural gas play and the Deep Basin natural gas area in British Columbia, as well as US$19.6 million of spending on our Marcellus carry obligation. At June 30, 2010 our remaining carry obligation was US$208.7 million. Property dispositions during the quarter related to our planned divestment program of non-core conventional assets for proceeds of $197.8 million before adjustments of approximately $16 million. For further details, refer to the Acquisitions and Dispositions section previously in the MD&A.

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

	Three months ended June 30,		Six months ended June 30,	
Capital Expenditures ($ millions)	**2010**	**2009**	**2010**	**2009**
Development expenditures[1][2]	**$ 79.8**	$ 18.0	**$ 156.9**	$ 94.6
Plant and facilities	**10.7**	16.9	**28.9**	36.9
Development Capital	**90.5**	34.9	**185.8**	131.5
Office	**0.8**	2.5	**1.2**	3.1
Sub-total	**91.3**	37.4	**187.0**	134.6
Property and land acquisitions[2][3]	**311.9**	29.1	**353.2**	33.7
Property dispositions[3]	**(181.3)**	(1.7)	**(182.8)**	(1.7)
Total Net Capital Expenditures	**$ 221.9**	$ 64.8	**$ 357.4**	$ 166.6
Total Capital Expenditures financed with cash flow	**$ 67.5**	$ 64.8	**$ 161.1**	$ 166.6
Total Capital Expenditures financed with debt and equity	**335.7**	–	**379.1**	–
Proceeds received on property dispositions	**(181.3)**	–	**(182.8)**	–
Total Net Capital Expenditures	**$ 221.9**	$ 64.8	**$ 357.4**	$ 166.6

(1) Development expenditures are net of DRC.
(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 are anticipating additional development capital spending in 2010 with respect to our recent acquisitions. As a result we are increasing our 2010 guidance for development capital spending to $485 million from $425 million, net of $27 million DRC.

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

For the three and six months ended June 30, 2010, DDA&A was $164.0 million and $323.5 million respectively compared to $163.8 million and $326.4 million in the comparable periods of 2009. DDA&A per BOE for the three months ended June 30, 2010 was $21.23/BOE compared to $19.05/BOE during the corresponding period in 2009. For the six months ended June 30, 2010, DDA&A increased to $21.07/BOE from $19.03/BOE during the same period in 2009. The increase in depletion per BOE is due to the negative reserve revisions recorded at December 31, 2009.

No impairment of the Fund's assets existed at June 30, 2010 using year-end reserves updated for development activity, acquisition and disposition activity and management's estimates of future prices.

Goodwill

The goodwill balance of $609.5 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 June 30, 2010.

Asset Retirement Obligations

In connection with our operations, we anticipate we will incur abandonment and reclamation costs for 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 in wells and facilities, estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. We have estimated the net present value of our total asset retirement obligations to be approximately $215.7 million at June 30, 2010, which is $14.8 million lower than $230.5 million at March 31, 2010. The majority of the reduction related to asset retirement obligations carried on the non-core properties that were divested during the second quarter. See Note 3 for further detail.

Actual asset retirement costs are incurred at different times compared to the recording of amortization and accretion charges. Actual asset retirement costs will be incurred over the next 66 years with the majority between 2030 and 2049.

Taxes

Future Income Taxes

Our future income tax recovery was $21.2 million and $21.7 million for the three and six months ended June 30, 2010 respectively, compared to a recovery of $32.9 million and $59.0 for the same periods in 2009. The decrease is mainly due to higher net income in 2010.

Current Income Taxes

In our current structure, payments are made between the operating entities and the Fund, which ultimately transfers both income and future income tax liability to our unitholders. As a result minimal cash income taxes are generally paid by our Canadian operating entities. Effective January 1, 2011 we expect to convert to a corporation and will be subject to normal Canadian corporate taxes. Within the context of current commodity prices and capital spending plans, we do not expect to pay current taxes in Canada until approximately 2013, as we expect to utilize our tax pools to reduce taxes otherwise payable. This estimate does not include the effect of future acquisitions or divestments.

The amount of current taxes recorded throughout the year with respect to our U.S. operations is dependent upon income levels and the timing of both capital expenditures and the repatriation of funds to Canada. For the three and six months ended June 30, 2010, we recorded current income taxes of $0.4 million compared to $1.8 million and $2.6 million during the same periods in 2009. The decrease from 2009 is due to higher capital expenditures during 2010. We expect current income and withholding taxes to average approximately 5% of cash flow from U.S. operations in 2010.

Net Income

Our net income for the second quarter of 2010 was $31.3 million or $0.18 per trust unit compared to a net loss of $3.6 million or $0.02 per trust unit for the same period in 2009. Net income for the six months ended June 30, 2010 was $111.3 million or $0.63 per trust unit compared to $48.2 million or $0.29 per trust unit for the same period in 2009. The $63.1 million increase in net income for the six months ended June 30, 2010 was primarily due to an increase in oil and gas sales of $74.8 million, a decrease in operating costs of $17.7 million and an increase in our commodity derivative instruments gains of $14.9 million. These gains were partially offset by a decrease in our future income tax recovery of $37.3 million.

Cash Flow from Operating Activities ("Cash flow")

Cash flow for the three and six months ended June 30, 2010 was $163.4 million ($0.92 per trust unit) and $352.7 million ($1.99 per trust unit) respectively, compared to $210.6 million ($1.27 per trust unit) and $380.0 million ($2.29 per trust unit) for the three and six months ended June 30, 2009. The decrease in cash flow during 2010 was due to lower cash gains on our commodity derivative instruments and increases in both interest expense and realized foreign exchange losses, partially offset by higher oil and gas sales and lower operating and general and administrative expenses.

Selected Financial Results

	Three months ended June 30, 2010			Three months ended June 30, 2009		
Per BOE of production (6:1)	Operating Cash Flow[(1)]	Non-Cash & Other Items	Total	Operating Cash Flow[(1)]	Non-Cash & Other Items	Total
Production per day			84,909			94,501
Weighted average sales price[(2)]	$ 41.18	$ –	$ 41.18	$ 35.60	$ –	$ 35.60
Royalties	(7.35)	–	(7.35)	(6.28)	–	(6.28)
Commodity derivative instruments	2.23	2.02	4.25	4.95	(5.80)	(0.85)
Operating costs	(10.09)	0.27	(9.82)	(9.58)	(0.35)	(9.93)
General and administrative	(1.66)	(0.23)	(1.89)	(2.27)	(0.22)	(2.49)
Interest and other expenses	(1.79)	(1.99)	(3.78)	1.02	(2.06)	(1.04)
Current income tax	(0.05)	–	(0.05)	(0.21)	–	(0.21)
Restoration and abandonment cash costs	(0.46)	0.46	–	(0.29)	0.29	–
Depletion, depreciation, amortization and accretion	–	(21.23)	(21.23)	–	(19.05)	(19.05)
Future income tax recovery/(expense)	–	2.74	2.74	–	3.83	3.83
Total per BOE	$ 22.01	$ (17.96)	$ 4.05	$ 22.94	$ (23.36)	$ (0.42)

(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.

	Six months ended June 30, 2010			Six months ended June 30, 2009		
Per BOE of production (6:1)	Operating Cash Flow[(1)]	Non-Cash & Other Items	Total	Operating Cash Flow[(1)]	Non-Cash & Other Items	Total
Production per day			84,815			94,739
Weighted average sales price[(2)]	$ 44.39	$ –	$ 44.39	$ 35.42	$ –	$ 35.42
Royalties	(7.95)	–	(7.95)	(6.36)	–	(6.36)
Commodity derivative instruments	1.38	2.93	4.31	5.16	(2.17)	2.99
Operating costs	(10.00)	0.11	(9.89)	(9.77)	(0.12)	(9.89)
General and administrative	(2.06)	(0.17)	(2.23)	(2.16)	(0.19)	(2.35)
Interest and other expenses	(1.33)	(0.37)	(1.70)	0.07	(1.33)	(1.26)
Current income tax	(0.03)	–	(0.03)	(0.15)	–	(0.15)
Restoration and abandonment cash costs	(0.51)	0.51	–	(0.36)	0.36	–
Depletion, depreciation, amortization and accretion	–	(21.07)	(21.07)	–	(19.03)	(19.03)
Future income tax recovery/(expense)	–	1.42	1.42	–	3.44	3.44
Total per BOE	$ 23.89	$ (16.64)	$ 7.25	$ 21.85	$ (19.04)	$ 2.81

(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 Canadian and U.S. Results

The following tables provide a geographical analysis of key operating and financial results for the three and six months ended June 30, 2010 and 2009.

	Three months ended June 30, 2010			Three months ended June 30, 2009		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	**277,811**	**18,755**	**296,566**	323,941	14,252	338,193
Crude oil (bbls/day)	**23,260**	**8,299**	**31,559**	25,221	8,494	33,715
Natural gas liquids (bbls/day)	**3,922**	**–**	**3,922**	4,420	–	4,420
Total Daily Sales (BOE/day)	**73,484**	**11,425**	**84,909**	83,632	10,869	94,501
Pricing[1]						
Natural gas (per Mcf)	**$ 3.69**	**$ 5.11**	**$ 3.78**	$ 3.45	$ 4.34	$ 3.49
Crude oil (per bbl)	**68.47**	**69.41**	**68.72**	59.56	60.53	59.80
Natural gas liquids (per bbl)	**47.55**	**–**	**47.55**	35.47	–	35.47
Capital Expenditures						
Development capital and office	**$ 45.9**	**$ 45.4**	**$ 91.3**	$ 31.8	$ 6.3	$ 38.1
Acquisitions of oil and gas properties	**137.7**	**174.2**	**311.9**	28.1	0.3	28.4
Dispositions of oil and gas properties	**(181.2)**	**–**	**(181.2)**	(1.7)	–	(1.7)
Revenues						
Oil and gas sales[1]	**$ 257.1**	**$ 61.1**	**$ 318.2**	$ 253.7	$ 52.5	$ 306.2
Royalties[2]	**(42.5)**	**(14.3)**	**(56.8)**	(42.0)	(12.0)	(54.0)
Commodity derivative instruments gain/(loss)	**32.9**	**–**	**32.9**	(7.3)	–	(7.3)
Expenses						
Operating	**$ 72.3**	**$ 3.6**	**$ 75.9**	$ 81.9	$ 3.5	$ 85.4
General and administrative	**11.6**	**3.0**	**14.6**	19.8	1.6	21.4
Depletion, depreciation, amortization and accretion	**142.2**	**21.8**	**164.0**	141.5	22.3	163.8
Current income taxes expense/(recovery)	**–**	**0.4**	**0.4**	–	1.8	1.8

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

(CDN$ millions, except per unit amounts)	Six months ended June 30, 2010 Canada	U.S.	Total	Six months ended June 30, 2009 Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	**280,620**	**17,117**	**297,737**	324,865	13,673	338,538
Crude oil (bbls/day)	**23,596**	**7,672**	**31,268**	25,300	8,775	34,075
Natural gas liquids (bbls/day)	**3,924**	**–**	**3,924**	4,241	–	4,241
Total Daily Sales (BOE/day)	**74,290**	**10,525**	**84,815**	83,685	11,054	94,739
Pricing(1)						
Natural gas (per Mcf)	**$ 4.35**	**$ 5.99**	**$ 4.44**	$ 4.28	$ 4.83	$ 4.31
Crude oil (per bbl)	**71.15**	**71.57**	**71.25**	51.43	50.01	51.06
Natural gas liquids (per bbl)	**52.49**	**–**	**52.49**	37.91	–	37.91
Capital Expenditures						
Development capital and office	**$ 103.7**	**$ 83.3**	**$ 187.0**	$ 120.8	$ 17.1	$ 137.9
Acquisitions of oil and gas properties	**142.9**	**210.3**	**353.2**	29.9	0.5	30.4
Dispositions of oil and gas properties	**(182.8)**	**–**	**(182.8)**	(1.7)	–	(1.7)
Revenues						
Oil and gas sales(1)	**$ 563.5**	**$ 118.0**	**$ 681.5**	$ 516.0	$ 91.4	$ 607.4
Royalties(2)	**(94.5)**	**(27.7)**	**(122.2)**	(88.5)	(20.5)	(109.0)
Commodity derivative instruments gain/(loss)	**66.2**	**–**	**66.2**	51.3	–	51.3
Expenses						
Operating	**$ 144.6**	**$ 7.2**	**$ 151.8**	$ 162.2	$ 7.3	$ 169.5
General and administrative	**28.4**	**5.8**	**34.2**	36.8	3.5	40.3
Depletion, depreciation, amortization and accretion	**285.0**	**38.5**	**323.5**	280.4	46.0	326.4
Current income taxes expense/(recovery)	**–**	**0.4**	**0.4**	–	2.6	2.6

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

Quarterly Financial Information

Crude oil and natural gas sales increased to mid-2008 due to increased commodity prices and increased production from the Focus acquisition. Oil and natural gas sales decreased in the latter part of 2008 with the sharp decline in commodity prices and were flat during 2009 as rising crude oil prices were largely offset by declining natural gas prices. Higher commodity prices during the beginning of 2010 more than offset lower production levels resulting in increased oil and gas sales. During the second quarter of 2010 oil and gas sales decreased due to a decline in commodity prices as production levels have remained relatively unchanged from the first quarter.

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

Quarterly Financial Information ($ 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				
Second quarter	**$ 318.2**	**$ 31.3**	**$ 0.18**	**$ 0.18**
First quarter	**363.3**	**80.0**	**0.45**	**0.45**
Total	**$ 681.5**	**$ 111.3**	**$ 0.63**	**$ 0.63**
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
2008				
Fourth quarter	$ 418.3	$ 189.5	$ 1.15	$ 1.15
Third quarter	647.8	465.8	2.82	2.82
Second quarter	734.4	112.2	0.68	0.68
First quarter	503.7	121.4	0.82	0.82
Total	$ 2,304.2	$ 888.9	$ 5.54	$ 5.53

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

LIQUIDITY AND CAPITAL RESOURCES

Credit Facility

During the quarter we extended our unsecured, covenant-based bank credit facility for a three year term, maturing June 30, 2013. Based on our expected cash requirements, ongoing access to debt and equity markets and 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 between 0.7% and 0.9%. 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. At June 30, 2010 we had $170.0 million drawn on the facility and we were in compliance with all covenants. 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.

Distribution Policy

The amount of cash distributions paid to unitholders is proposed by management and approved by the Board of Directors. We continually assess distribution levels with respect to anticipated cash flows, debt levels, capital spending plans and capital market conditions. The level of cash withheld varies and is dependent upon numerous factors, the most significant of which include the prevailing commodity price environment, our current levels of production, debt obligations, funding requirements for our development capital program and our access to equity markets.

We have maintained our monthly distribution rate of $0.18 per unit distribution since February 2009 and have been able to manage our distribution levels and capital spending in order to preserve our balance sheet strength.

Sustainability of our Distributions and Asset Base

As an oil and gas producer we have a declining asset base and therefore rely on ongoing development activities and acquisitions to replace production and add additional reserves. Our future crude oil and natural gas production is highly dependent on our success in exploiting our asset base and acquiring or developing additional reserves. To the extent we are unsuccessful in these activities, our cash distributions could be reduced.

Development activities and acquisitions may be funded internally by withholding a portion of cash flow or through external sources of capital such as debt or the issuance of equity. To the extent that we withhold cash flow to finance these activities, the amount of cash distributions to our unitholders may be reduced. Should external sources of capital become limited or unavailable, our ability to make the necessary development expenditures and acquisitions to maintain or expand our asset base may be impaired and ultimately reduce the amount of cash distributions.

Cash Flow from Operating Activities, Cash Distributions and Payout Ratio

Cash flow from operating activities and cash distributions are reported on the Consolidated Statements of Cash Flows. During the second quarter of 2010, cash distributions of $95.9 million were funded entirely through cash flow of $163.4 million. For the six months ended June 30, 2010, our cash distributions were $191.6 million and were funded entirely through cash flow of $352.7 million.

Our payout ratio, which is calculated as cash distributions divided by cash flow, was 59% and 54% for the three and six months ended June 30, 2010 respectively, compared to 43% and 47% for the same periods in 2009. Our adjusted payout ratio, which is calculated as cash distributions plus development capital and office expenditures divided by cash flow, was 115% for the second quarter and 107% for the six months ended June 30, 2010 compared to 60% and 83% for the same periods in 2009. The increase in our payout ratio is mainly due to the decrease in cash flow. The increase in our adjusted payout ratio is due to the combination of the increase in development capital and office expenditures and the decrease in cash flow. See "Non-GAPP Measures" above.

For the three months ended June 30, 2010, our cash distributions exceeded our net income by $64.6 million (2009 – $93.2 million). For the six months ended June 30, 2010 our cash distributions exceeded our net income by $80.3 million (2009 – $130.9 million). Non-cash items such as changes in the fair value of our derivative instruments and future income taxes cause net income to fluctuate between periods but do not reduce or increase our cash flow. Future income taxes can fluctuate from period to period as a result of changes in tax rates as well as changes in interest, royalties and dividends from our operating subsidiaries paid to the Fund. In addition, we believe that other non-cash charges such as DDA&A are not a good proxy for the cost of maintaining our productive capacity as they are based on the historical cost of our PP&E and not the fair market value of replacing those assets within the context of the current environment.

It is not practical to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities in the oil and gas sector due to the nature of reserve reporting, natural reservoir declines and the risks involved with capital investment. As a result, we do not distinguish maintenance capital separately from development capital spending. The level of investment in a given period may not be sufficient to replace productive capacity given the natural declines associated with oil and natural gas assets. In these instances a portion of the cash distributions paid to unitholders may represent a return of the unitholders' capital.

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

($ millions, except per unit amounts)	Three months ended June 30, 2010	Six months ended June 30, 2010	Year ended December 31, 2009	Year ended December 31, 2008
Cash flow from operating activities	**$ 163.4**	**$ 352.7**	$ 775.8	$ 1,262.8
Cash distributions	**95.9**	**191.6**	368.2	786.1
Excess of cash flow over cash distributions	**$ 67.5**	**$ 161.1**	$ 407.6	$ 476.7
Net income	**$ 31.3**	**$ 111.3**	$ 89.1	$ 888.9
(Shortfall)/excess of net income over cash distributions	**$ (64.6)**	**$ (80.3)**	$ (279.1)	$ 102.8
Cash distributions per weighted average trust unit	**$ 0.54**	**$ 1.08**	$ 2.17	$ 4.89
Payout ratio(1)	**59%**	**54%**	47%	62%
Adjusted Payout ratio(1)(2)	**115%**	**107%**	83%	106%

(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.

(2) Land acquisitions in prior periods have been reclassified from development capital expenditures to property acquisitions to conform with the current year presentation.

Debt

Total debt at June 30, 2010 was $698.4 million, an increase of $139.5 million from $558.9 million at December 31, 2009. Long-term debt at June 30, 2010 was comprised of $170.0 million of bank indebtedness and $528.4 million of senior unsecured notes.

The increase of $170.0 million in our bank indebtedness is mainly the result of funding $130.6 million of net acquisition and disposition activity during the quarter and making the first principal repayment of US$35.0 million (CDN$53.7 million) under our US$175 million senior note which reflects the associated settlement under the CCIRS.

Our working capital at June 30, 2010 increased by $16.4 million compared to December 31, 2009 primarily due to decreased accounts payable balances at June 30, 2010. Our working capital excludes cash, current deferred financial assets and credits, the current portion of long-term debt, and future income taxes.

We continue to maintain a conservative balance sheet as demonstrated below:

Financial Leverage and Coverage	June 30, 2010	December 31, 2009
Long-term debt to cash flow (12 month trailing)	**0.9x**	0.6x
Cash flow to interest expense (12 month trailing)(1)	**17.0x**	25.4x
Long-term debt to long-term debt plus equity(2)	**14%**	10%

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

Payments with respect to the bank facilities, senior unsecured notes and other third party debt have priority over claims of and future distributions to the unitholders. Unitholders have no direct liability should cash flow be insufficient to repay this indebtedness. The agreements governing these bank facilities and senior unsecured notes stipulate that if we default or fail to comply with certain covenants, the ability of the Fund's operating subsidiaries to make payments to the Fund and consequently the Fund's ability to make distributions to the unitholders may be restricted. At June 30, 2010, we are in compliance with our debt covenants, the most restrictive of which limits our long-term debt to three times trailing cash flow. Refer to "Debt of Enerplus" in our Annual Information Form for the year ended December 31, 2009 for a detailed description of these covenants.

We expect to have adequate liquidity under our bank credit facility, from cash flow and from our asset disposition program to fund planned development capital spending and working capital requirements for 2010.

ACCUMULATED DEFICIT

We have historically paid cash distributions in excess of accumulated earnings resulting in an accumulated deficit. 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 177,714,000 trust units outstanding at June 30, 2010 compared to 166,022,000 trust units at June 30, 2009 and 177,061,000 trust units outstanding at December 31, 2009. Trust units outstanding at June 30, 2010 include 4,257,000 exchangeable limited partnership units which are convertible at the option of the holder into 0.425 of an Enerplus trust unit (1,809,000 trust units). During the six months ended June 30, 2010, 2,125,000 partnership units were converted into 903,000 trust units.

During the three months ended June 30, 2010, 344,000 trust units (2009 – 194,000) 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 $7.2 million (2009 – $4.5 million) of additional equity to the Fund. For the six months ended June 30, 2010, $13.9 million of additional equity (2009 – $9.9 million) and 653,000 trust units (2009 – 432,000) were issued pursuant to the DRIP and the trust unit rights incentive plan. For further details see Note 7.

The weighted average basic number of trust units outstanding for the six months ended June 30, 2010 was 177,349,000 (2009 – 165,807,000). At July 28, 2010, we had 177,819,000 trust units outstanding including the equivalent limited partnership units.

INCOME TAXES

The following is a general discussion of the Canadian and U.S. tax consequences of holding Enerplus trust units as capital property. The summary is not exhaustive in nature and is not intended to provide legal or tax advice. Investors or potential unitholders should consult their own legal or tax advisors as to their particular tax consequences.

Canadian Unitholders

We qualify as a mutual fund trust under the Income Tax Act (Canada) and accordingly, trust units of Enerplus are qualified investments for RRSPs, RRIFs, RESPs, DPSPs and TFSAs. Each year we have historically transferred all of our taxable income to the unitholders by way of distributions.

In computing income, unitholders are required to include the taxable portion of distributions received in that year. An investor's adjusted cost base ("ACB") in a trust unit equals the purchase price of the trust unit less any non-taxable cash distributions received from the date of acquisition. To the extent a unitholder's ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholder's ACB will be brought to zero.

For 2010, we estimate that 95% of cash distributions will be taxable and 5% will be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon, among other things, production, commodity prices and cash flow experienced throughout the year.

U.S. Unitholders

U.S. unitholders who received cash distributions are subject to at least a 15% Canadian withholding tax. The withholding tax is applied to both the taxable portion of the distribution as computed under Canadian tax law and the non-taxable portion of the distribution. U.S. taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid.

For U.S. taxpayers, the taxable portion of cash distributions are considered to be a dividend for U.S. tax purposes. For most U.S. taxpayers this should be a "Qualified Dividend" eligible for the reduced tax rate. The 15% preferred rate of tax on "Qualified Dividends" is currently scheduled to expire at the end of 2010. We are unable to determine whether or to what extent the preferred rate of tax on "Qualified Dividends" may be extended.

For 2010, we estimate that 90% of cash distributions will be taxable to most U.S. investors and 10% will be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon production, commodity prices and cash flow experienced throughout the year.

In July 2010, we estimated our non-resident ownership to be 68%.

2010 GUIDANCE

The following provides our updated 2010 guidance and includes the impact of our non-core asset disposition and our Fort Berthold acquisition. The summary below does not include any further acquisitions or divestments that may occur during the remainder of 2010:

Summary of 2010 Expectations	Target	Comments
Average annual production	85,000 BOE/day	
Exit rate 2010 production	86,000 BOE/day	Assumes $485 million development capital spending, net of $27 million of Alberta DRC
2010 production mix	57% gas, 43% liquids	
Average royalty rate	18%	Percentage of gross sales
Operating costs	$10.20/BOE	
G&A costs	$2.45/BOE	Includes non-cash charges of $0.20/BOE (trust unit rights incentive plan)
U.S. income and withholding tax – cash costs	5%	Applied to net cash flow generated by U.S. operations
Average interest and financing costs	8%	Based on current fixed rate contracts, forward interest rates and credit facility extension fees
Corporate conversion and simplification	$3 million or $0.10/BOE	Fees related to our conversion from a trust to a corporation and simplification of our underlying corporate structure
Development capital spending	$485 million, net of Alberta DRC of $27 million	Within the context of current commodity prices
Marcellus carry commitment spending	$64 million	Will be reported as a property acquisition

INTERNAL CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the period beginning on April 1, 2010 and ended on June 30, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

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

In October 2009 the Accounting Standards Board ("AcSB") issued a third and final IFRS Omnibus Exposure Draft confirming that publicly accountable enterprises will be 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 by Enerplus for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

We have not made any material changes to our transition plan that would impact the accounting policy choices or voluntary exemptions we expect to adopt at the transition date, January 1, 2010 noted previously. For a discussion of our approach to the IFRS transition and a summary of the expected impact please refer to our 2009 MD&A as filed February 24, 2010 on www.sedar.com.

We have made significant progress on our IFRS transition during 2010 and are on schedule with our changeover plan. We have continued to analyze accounting policy alternatives and have drafted our preliminarily IFRS accounting policies. IFRS education sessions have been held with internal stakeholders and these sessions will continue throughout 2010. Our IFRS accounting policies are expected to be finalized in the third quarter of 2010 with quantification and communication of IFRS impacts to follow. We will continue to update our IFRS changeover plan to reflect the ongoing changes in accounting standards proposed or issued by the International Accounting Standards Board.

ADDITIONAL INFORMATION

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "target", "budget", "strategy" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: asset dispositions and the use of proceeds therefrom; our corporate strategy, including transition from an income trust to a corporate form and the timing thereof; expected oil, natural gas and natural gas liquids production volumes and product mix; future oil and natural gas prices and the Fund's commodity risk management programs; cash flow sensitivities to commodity price, production, foreign exchange and interest rate changes; expected operating, G&A and trust conversion expenses and royalty and interest rates; capital expenditures and the allocation thereof; future well and operating results; future acquisitions and production and reserves growth; receipt of required regulatory approvals; the amount of future abandonment and reclamation costs and asset retirement obligations; taxes payable by the Fund and its subsidiaries; the tax pools of the Fund and its subsidiaries; renewal of our credit facility and the borrowing costs associated with the credit facility; credit risk mitigation programs; future debt levels, financial capacity, liquidity and capital resources; cash distributions and dividends and the tax treatment thereof; future contractual commitments; our transition to IFRS and the impact of that change on our financial results; reliance on industry partners to develop and expand our assets and operations; and future environmental and asset retirement obligations and the costs associated therewith.

The forward-looking information and statements contained in this MD&A reflect several material factors and expectations and assumptions of the Fund including, without limitation: that the Fund will conduct its operations in a manner consistent with its expectations and, where applicable, consistent with past practice; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; the accuracy of the estimates of the Fund's reserve and resource volumes; certain commodity price and other cost assumptions; the continued availability of adequate debt and/or equity financing and cash flow to fund its capital and operating requirements as needed; and the extent of its liabilities. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve 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 or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of the Fund's products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans the Fund or by third party operators of the Fund's properties, increased debt levels or debt service requirements; inaccurate estimation of the Fund's 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 the Fund's public disclosure documents (including, without limitation, those risks and contingencies described above and under "Risk Factors and Risk Management" in this MD&A and under "Risk Factors" in the Fund's Annual Information Form dated March 12, 2010, which is available on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com and which forms part of our Form 40-F filed with the SEC on March 12, 2010 and available at www.sec.gov.

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and none of the Fund or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

USE OF "BOE" AND "MMCFE"; PRESENTATION OF PRODUCTION INFORMATION

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. "MMcfe" means million cubic feet of gas equivalent. Enerplus has adopted the standard of one barrel of oil to six thousand cubic feet of gas (1 barrel: 6 Mcf) when converting oil to MMcfes. MMcfes may be misleading, particularly if used in isolation. An MMcfe conversion ratio of 1 barrel: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In accordance with Canadian practice, production volumes and revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise stated.

Consolidated Balance Sheets

(CDN$ thousands) unaudited	June 30, 2010	December 31, 2009
Assets		
Current assets		
Cash	**$ 549**	$ 73,558
Accounts receivable	**133,482**	142,009
Deferred financial assets *(Note 8)*	**44,992**	20,364
Future income taxes	**–**	4,995
Other current	**8,342**	5,041
	187,365	245,967
Property, plant and equipment *(Note 2)*	**5,043,661**	5,000,523
Goodwill	**609,529**	607,438
Deferred financial assets *(Note 8)*	**3,188**	1,997
Other assets *(Note 8)*	**50,719**	49,591
	5,707,097	5,659,549
	$ 5,894,462	$ 5,905,516
Liabilities		
Current liabilities		
Accounts payable	**$ 235,737**	$ 257,519
Distributions payable to unitholders	**31,988**	31,871
Current portion of long-term debt *(Note 4)*	**–**	36,631
Future income taxes	**6,654**	–
Deferred financial credits *(Note 8)*	**14,664**	37,437
	289,043	363,458
Long-term debt *(Note 4)*	**698,366**	522,276
Deferred financial credits *(Note 8)*	**39,262**	54,788
Future income taxes	**530,640**	561,585
Asset retirement obligations *(Note 3)*	**215,702**	230,465
	1,483,970	1,369,114
Equity		
Unitholders' capital *(Note 7)*	**5,732,068**	5,715,614
Accumulated deficit	**(1,540,605)**	(1,460,283)
Accumulated other comprehensive income/(loss)	**(70,014)**	(82,387)
	4,121,449	4,172,944
	$ 5,894,462	$ 5,905,516

Consolidated Statements of Accumulated Deficit and Accumulated Other Comprehensive Income

	Three months ended June 30,		Six months ended June 30,	
(CDN$ thousands) unaudited	**2010**	**2009**	**2010**	**2009**
Accumulated income, beginning of period	**$ 3,344,939**	$ 3,227,605	**$ 3,264,936**	$ 3,175,819
Net income/(loss)	**31,296**	(3,569)	**111,299**	48,217
Accumulated income, end of period	**3,376,235**	3,224,036	**3,376,235**	3,224,036
Accumulated cash distributions, beginning of period	**(4,820,931)**	(4,446,555)	**(4,725,219)**	(4,357,018)
Cash distributions	**(95,909)**	(89,610)	**(191,621)**	(179,147)
Accumulated cash distributions, end of period	**(4,916,840)**	(4,536,165)	**(4,916,840)**	(4,536,165)
Accumulated deficit, end of period	**$ (1,540,605)**	$ (1,312,129)	**$ (1,540,605)**	$ (1,312,129)
Accumulated other comprehensive income/(loss), beginning of period	**$ (109,011)**	$ 73,122	**$ (82,387)**	$ 48,606
Other comprehensive income/(loss)	**38,997**	(66,924)	**12,373**	(42,408)
Accumulated other comprehensive income/(loss), end of period	**$ (70,014)**	$ 6,198	**$ (70,014)**	$ 6,198
Total accumulated deficit and other comprehensive income/(loss)	**$ (1,610,619)**	$ (1,305,931)	**$ (1,610,619)**	$ (1,305,931)

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Income

(CDN$ thousands) unaudited	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Revenues				
Oil and gas sales	**$ 325,190**	$ 312,537	**$ 694,830**	$ 620,052
Royalties	**(56,808)**	(54,009)	**(122,175)**	(109,047)
Commodity derivative instruments *(Note 8)*	**32,866**	(7,336)	**66,213**	51,309
Other income	**89**	31	**353**	175
	301,337	251,223	**639,221**	562,489
Expenses				
Operating	**75,882**	85,389	**151,809**	169,519
General and administrative	**14,631**	21,447	**34,165**	40,317
Transportation	**6,989**	6,356	**13,344**	12,657
Interest *(Note 5)*	**15,674**	21,575	**23,164**	33,572
Foreign exchange *(Note 6)*	**13,633**	(12,611)	**3,224**	(11,758)
Depletion, depreciation, amortization and accretion	**164,042**	163,798	**323,517**	326,358
	290,851	285,954	**549,223**	570,665
Income/(loss) before taxes	**10,486**	(34,731)	**89,998**	(8,176)
Current taxes	**409**	1,777	**409**	2,616
Future income tax recovery	**(21,219)**	(32,939)	**(21,710)**	(59,009)
Net Income/(loss)	**$ 31,296**	$ (3,569)	**$ 111,299**	$ 48,217
Net income/(loss) per trust unit				
Basic	**$ 0.18**	$ (0.02)	**$ 0.63**	$ 0.29
Diluted	**$ 0.18**	$ (0.02)	**$ 0.63**	$ 0.29
Weighted average number of trust units outstanding (thousands)				
Basic	**177,526**	165,899	**177,349**	165,807
Diluted	**177,862**	166,264	**177,686**	165,807

Consolidated Statements of Comprehensive Income

(CDN$ thousands) unaudited	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Net income/(loss)	**$ 31,296**	$ (3,569)	**$ 111,299**	$ 48,217
Other comprehensive income/(loss), net of tax:				
Unrealized gain on marketable securities	**81**	–	**81**	–
Change in cumulative translation adjustment	**38,916**	(66,924)	**12,292**	(42,408)
Other comprehensive income/(loss)	**38,997**	(66,924)	**12,373**	(42,408)
Comprehensive income/(loss)	**$ 70,293**	$ (70,493)	**$ 123,672**	$ 5,809

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Operating Activities				
Net income/(loss)	**$ 31,296**	$ (3,569)	**$ 111,299**	$ 48,217
Non-cash items add / (deduct):				
Depletion, depreciation, amortization and accretion	**164,042**	163,798	**323,517**	326,358
Change in fair value of derivative instruments *(Note 8)*	**(40,937)**	84,110	**(64,118)**	67,389
Unit based compensation *(Note 7(d))*	**1,784**	1,877	**2,543**	3,256
Foreign exchange on translation of senior notes *(Note 6)*	**20,873**	(13,270)	**5,507**	(5,033)
Future income tax	**(21,219)**	(32,939)	**(21,710)**	(59,009)
Amortization of senior notes premium	**(180)**	(192)	**(360)**	(394)
Cross currency interest rate swap principal settlement	**17,969**	–	**17,969**	–
Asset retirement obligations settled *(Note 3)*	**(3,590)**	(2,530)	**(7,881)**	(6,182)
	170,038	197,285	**366,766**	374,602
Decrease/(Increase) in non-cash operating working capital	**(6,655)**	13,323	**(14,026)**	5,394
Cash flow from operating activities	**163,383**	210,608	**352,740**	379,996
Financing Activities				
Issue of trust units, net of issue costs *(Note 7)*	**7,179**	4,513	**13,911**	9,913
Cash distributions to unitholders	**(95,909)**	(89,610)	**(191,621)**	(179,147)
Increase/(Decrease) in bank credit facilities	**170,007**	(350,857)	**170,007**	(283,940)
Issuance/(Repayment) of senior unsecured notes	**(35,697)**	338,735	**(35,697)**	338,735
Cross currency interest rate swap principal settlement	**(17,969)**	–	**(17,969)**	–
Decrease/(Increase) in non-cash financing working capital	**60**	35	**117**	(11,514)
Cash flow from financing activities	**27,671**	(97,184)	**(61,252)**	(125,953)
Investing Activities				
Capital expenditures	**(91,285)**	(38,013)	**(187,015)**	(137,887)
Property and land acquisitions	**(311,874)**	(28,416)	**(353,201)**	(30,393)
Property dispositions	**181,238**	1,723	**182,776**	1,736
Purchase of marketable securities	**(450)**	–	**(1,016)**	–
Decrease/(Increase) in non-cash investing working capital	**6,219**	(46,633)	**(5,503)**	(93,034)
Cash flow from investing activities	**(216,152)**	(111,339)	**(363,959)**	(259,578)
Effect of exchange rate changes on cash	**(452)**	(2,035)	**(538)**	(1,212)
Change in cash	**(25,550)**	50	**(73,009)**	(6,747)
Cash, beginning of period	**26,099**	125	**73,558**	6,922
Cash, end of period	**$ 549**	$ 175	**$ 549**	$ 175
Supplementary Cash Flow Information				
Cash income taxes (received)/paid	**$ 465**	$ (22,790)	**$ (7,816)**	$ (22,790)
Cash interest paid	**$ 22,912**	$ 7,198	**$ 24,387**	$ 9,899

See accompanying notes to the Consolidated Financial Statements

Notes to Consolidated Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of Enerplus Resources Fund ("Enerplus" or the "Fund") have been prepared by management following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2009. The note disclosure requirements for annual statements provide additional disclosure to that required for these interim statements. Accordingly, these interim statements should be read in conjunction with the Fund's consolidated financial statements for the year ended December 31, 2009. All amounts are stated in Canadian dollars unless otherwise specified.

2. PROPERTY, PLANT AND EQUIPMENT

($ thousands)	June 30, 2010	December 31, 2009
Property, plant and equipment	**$ 9,192,759**	$ 8,827,191
Accumulated depletion, depreciation and accretion	**(4,149,098)**	(3,826,668)
Net property, plant and equipment	**$ 5,043,661**	$ 5,000,523

Capitalized development general and administrative ("G&A") expenses of $9,762,000 (2009 – $12,813,000) are included in PP&E for the six months ended June 30, 2010. Excluded from PP&E for the depletion and depreciation calculation is $882,450,000 (December 31, 2009 – $462,989,000) related to undeveloped land and oil sands projects which have not yet commenced commercial production.

3. ASSET RETIREMENT OBLIGATIONS

The following is a reconciliation of the asset retirement obligations:

($ thousands)	Six months ended June 30, 2010	Year ended December 31, 2009
Asset retirement obligations, beginning of period	**$ 230,465**	$ 207,420
Changes in estimates	**26**	20,140
Property acquisition and development activity	**1,580**	4,420
Dispositions	**(15,842)**	(553)
Asset retirement obligations settled	**(7,881)**	(13,802)
Accretion expense	**7,354**	12,840
Asset retirement obligations, end of period	**$ 215,702**	$ 230,465

4. DEBT

($ thousands)	June 30, 2010	December 31, 2009
Current portion of long-term debt	**–**	36,631
Long-term:		
Bank credit facility	**170,007**	–
Senior notes:		
CDN$40 million (Issued June 18, 2009)	**40,000**	40,000
US$40 million (Issued June 18, 2009)	**42,424**	41,864
US$225 million (Issued June 18, 2009)	**238,635**	235,485
US$54 million (Issued October 1, 2003)	**57,272**	56,516
US$175 million (Issued June 19, 2002)*	**150,028**	148,411
	698,366	522,276
Total debt	**$ 698,366**	$ 558,907

* The June 19, 2011 principal repayment of US$35 million has not been included in current liabilities as we expect to refinance this amount with our long-term bank credit facility.

Bank Credit Facility

During the quarter 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 Fund has the ability to request an extension of the facility each year or repay the entire balance at the end of the term. At June 30, 2010 the Fund had $170.0 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 during the second quarter. The weighted average interest rate on the facility for the six months ended June 30, 2010 was 1.3% (June 30, 2009 – 1.2%).

Senior Notes

During the quarter the Fund made 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.

5. INTEREST EXPENSE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2010**	**2009**	**2010**	**2009**
Realized				
Interest on long-term debt	**$ 14,969**	$ 5,212	**$ 24,185**	$ 10,767
Unrealized				
(Gain)/loss on cross currency interest rate swap	**754**	17,904	**121**	25,868
(Gain)/loss on interest rate swaps	**131**	(1,349)	**(782)**	(2,669)
Amortization of the premium on senior unsecured notes	**(180)**	(192)	**(360)**	(394)
Interest expense	**$ 15,674**	$ 21,575	**$ 23,164**	$ 33,572

6. FOREIGN EXCHANGE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2010**	**2009**	**2010**	**2009**
Realized				
Foreign exchange loss/(gain)	**$ 16,906**	$ (13,991)	**$ 14,470**	$ (11,626)
Unrealized				
Foreign exchange loss/(gain) on translation of U.S. dollar denominated senior notes	**20,873**	(13,270)	**5,507**	(5,033)
Foreign exchange loss/(gain) on cross currency interest rate swap	**(21,576)**	10,643	**(15,562)**	2,325
Foreign exchange loss/(gain) on foreign exchange swaps	**(2,570)**	4,007	**(1,191)**	2,576
Foreign exchange loss/(gain)	**$ 13,633**	$ (12,611)	**$ 3,224**	$ (11,758)

7. UNITHOLDERS' CAPITAL

($ thousands)	**Six months ended June 30, 2010**	**Year ended December 31, 2009**
Trust units	**$ 5,631,386**	$ 5,580,933
Exchangeable limited partnership units	**72,398**	108,539
Contributed surplus	**28,284**	26,142
Balance, end of period	**$ 5,732,068**	$ 5,715,614

(a) Trust Units

Authorized: Unlimited number of trust units

(thousands)	Six months ended June 30, 2010		Year ended December 31, 2009	
Issued:	**Units**	**Amount**	**Units**	**Amount**
Balance, beginning of period	**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	**504**	**11,337**	1,061	24,120
Pursuant to rights incentive plan	**149**	**2,574**	4	85
Non-cash:				
Exchangeable limited partnership units exchanged	**903**	**36,141**	364	14,568
Trust unit rights incentive plan	**–**	**401**	–	–
	175,905	**$ 5,631,386**	174,349	$ 5,580,933
Equivalent exchangeable partnership units	**1,809**	**72,398**	2,712	108,539
Balance, end of period	**177,714**	**$ 5,703,784**	177,061	$ 5,689,472

* Distribution Reinvestment and Unit Purchase Plan.

(b) Exchangeable Limited Partnership Units

During the period January 1, 2010 to June 30, 2010, 2,125,000 exchangeable limited partnership units were converted into 903,000 trust units. As at June 30, 2010, the 4,257,000 outstanding exchangeable partnership units represent the equivalent of 1,809,000 trust units.

(thousands)	Six months ended June 30, 2010		Year ended December 31, 2009	
Issued:	**Units**	**Amount**	**Units**	**Amount**
Balance, beginning of period	**6,382**	**$ 108,539**	7,238	$ 123,107
Exchanged for trust units	**(2,125)**	**(36,141)**	(856)	(14,568)
Balance, end of period	**4,257**	**$ 72,398**	6,382	$ 108,539

(c) Contributed Surplus

($ thousands)	Six months ended June 30, 2010	Year ended December 31, 2009
Balance, beginning of period	**$ 26,142**	$ 19,600
Trust unit rights incentive plan (non-cash) – exercised	**(401)**	–
Trust unit rights incentive plan (non-cash) – expensed	**2,543**	6,542
Balance, end of period	**$ 28,284**	$ 26,142

(d) Trust Unit Rights Incentive Plan

As at June 30, 2010 a total of 6,099,000 rights were issued and outstanding pursuant to the Trust Unit Rights Incentive Plan ("Rights Incentive Plan") with an average exercise price of $31.79 per right. This represents 3.4% of the total trust units outstanding of which 2,948,000 rights, with an average exercise price of $40.60, 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 the Fund at the end of such calendar quarter may result in a reduction in the exercise price of the rights. Results for the first two quarters of 2010 did not reduce the exercise price of the outstanding rights.

Non-cash compensation costs related to rights issued charged to general and administrative for the three and six months ended June 30, 2010 were $1,784,000 ($0.01 per unit) and $2,543,000 ($0.01 per unit) respectively. Activity for the rights issued pursuant to the Rights Incentive Plan was as follows:

	Six months ended June 30, 2010			Year ended December 31, 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 period	**5,250**	**$**	**34,84**	4,001	$	45.05
Granted	**1,727**		**23.57**	2,001		17.28
Exercised	**(149)**		**17.24**	(4)		22.40
Forfeited and expired	**(729)**		**37.19**	(748)		38.61
End of period	**6,099**	**$**	**31.79**	5,250	$	34.84
Rights exercisable at end of period	**2,948**	**$**	**40.60**	2,393	$	46.03

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

(e) Basic and Diluted Per Trust Unit Calculations

Basic per-unit calculations are calculated using the weighted average number of trust units and exchangeable limited 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:

	Six months ended June 30,	
(thousands)	2010	2009
Weighted average units	**177,349**	165,807
Dilutive impact of rights	**337**	–
Diluted trust units	**177,686**	165,807

(f) Long Term Incentive Unit Plans

For the three and six months ended June 30, 2010 the Fund recorded cash compensation costs of $2,610,000 (2009 – $3,570,000) and $6,286,000 (2009 – $6,689,000) respectively, under the Performance Trust Unit ("PTU") and Restricted Trust Unit ("RTU") plans which are included in general and administrative expenses.

At June 30, 2010 there were 199,000 PTU's outstanding and 1,066,000 RTU's outstanding.

8. 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 and are reported at amortized cost. At June 30, 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 June 30, 2010 the Fund reported investments of publicly traded marketable securities at a fair value of $563,000. For the three months ended June 30, 2010, the change in fair value of these investments represented a gain of $113,000 ($81,000 net of tax). During 2009 the fund 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. As at June 30, 2010 the Fund 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.

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 June 30, 2010 the carrying value of these accounts approximated their fair value.

v. Long-term Debt

Bank Credit Facilities

The bank credit facilities are classified as other liabilities and are reported at amortized cost. At June 30, 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 Private Placement ($ thousands)	**Amortized Cost**	**Reported CDN$ Amortized Cost**	**CDN$ Fair Value**
CDN$40,000	CDN$40,000	$ 40,000	**$ 43,714**
US$40,000	US$40,000	42,424	**48,289**
US$225,000	US$225,000	238,635	**290,325**
US$54,000	US$54,000	57,272	**62,347**
US$175,000	US$141,455	150,028	**161,417**
		$ 528,359	**$ 606,092**

(b) Fair Value of Derivative Financial Instruments

The Fund 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.

The Fund's 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 Sheets result from recording derivative financial instruments at fair value. At June 30, 2010 a current deferred financial asset of $44,992,000, a current deferred financial credit of $14,664,000, a non-current deferred financial asset of $3,188,000 and a non-current deferred financial credit of $39,262,000 are recorded on the Consolidated Balance Sheet.

The deferred financial asset relating to crude oil instruments is $12,528,000 at June 30, 2010 including deferred premiums of $9,408,000. The deferred financial asset relating to natural gas instruments is $32,464,000 at June 30, 2010 including deferred premiums of $3,440,000.

The following table summarizes the fair value as at June 30, 2010 and change in fair value for the six months ended June 30, 2010:

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Commodity Derivative Instruments Oil	Commodity Derivative Instruments Gas	Total
Deferred financial assets/(credits), beginning of period	$ (6,064)	$ (63,336)	$ 1,997	$ (2,481)	$ (20,344)	$ 20,364	$ (69,864)
Change in fair value gain/(loss)	782(1)	15,441(2)	1,191(3)	1,732(4)	32,872(5)	12,100(5)	64,118
Deferred financial assets/(credits), end of period	**$ (5,282)**	**$ (47,895)**	**$ 3,188**	**$ (749)**	**$ 12,528**	**$ 32,464**	**$ (5,746)**
Balance sheet classification:							
Current asset/(liability)	**$ (3,021)**	**$ (10,894)**	**$ –**	**$ (749)**	**$ 12,528**	**$ 32,464**	**$ 30,328**
Non-current asset/(liability)	**$ (2,261)**	**$ (37,001)**	**$ 3,188**	**$ –**	**$ –**	**$ –**	**$ (36,074)**

(1) Recorded in interest expense.
(2) Recorded in foreign exchange expense (gain of $15,562) and interest expense (loss of $121).
(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:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2010**	**2009**	**2010**	**2009**
Gain/(loss) due to change in fair value	**$ 15,578**	$ (49,900)	**$ 44,972**	$ (37,235)
Net realized cash gains/(loss)	**17,288**	42,564	**21,241**	88,544
Commodity derivative instruments gain/(loss)	**$ 32,866**	$ (7,336)	**$ 66,213**	$ 51,309

(c) Commodity Risk Management

The Fund is exposed to commodity price fluctuations as part of its normal business operations, particularly in relation to its crude oil and natural gas sales. The Fund manages a portion of these risks through a combination of financial derivative and physical delivery sales contracts. The Fund's policy is to enter into commodity contracts considered appropriate to a maximum of 80% of forecasted production volumes net of royalties. The Fund's outstanding commodity derivative contracts as at July 28, 2010 are summarized below:

Crude Oil:

		WTI US$/bbl		
	Daily Volumes bbls/day	Purchased Call	Sold Put	Fixed Price and Swaps
Term				
Jul 1, 2010 – Dec 31, 2010				
Purchased Call	3,500	$ 95.00	–	–
Purchased Call	3,000	$ 90.00	–	–
Purchased Call	500	$ 92.50	–	–
Swap	1,500	–	–	$ 78.45
Swap	1,000	–	–	$ 78.80
Swap	1,000	–	–	$ 68.05
Swap	500	–	–	$ 69.33
Swap	500	–	–	$ 72.15
Swap	500	–	–	$ 74.30
Swap	500	–	–	$ 76.20
Swap	500	–	–	$ 76.38
Swap	500	–	–	$ 78.15
Swap	1,000	–	–	$ 79.20
Swap	500	–	–	$ 80.00
Swap	1,000	–	–	$ 83.40
Swap	1,000	–	–	$ 78.00
Swap	500	–	–	$ 80.15
Swap	500	–	–	$ 81.55
Swap	500	–	–	$ 84.35
Swap	500	–	–	$ 80.65
Swap	500	–	–	$ 82.00
Swap	500	–	–	$ 83.55
Swap	500	–	–	$ 85.65
Sold Put	5,000	–	$ 47.50	–
Jan 1, 2011 – Dec 31, 2011				
Purchased Call	1,000	$ 105.00	–	–
Purchased Call(1)	500	$ 105.00	–	–
Purchased Call(1)	1,000	$ 100.00	–	–
Swap	1,000	–	–	$ 87.65
Swap	500	–	–	$ 85.20
Swap(1)	500	–	–	$ 88.95
Swap(1)	500	–	–	$ 91.20
Swap(1)	500	–	–	$ 91.88
Swap(1)	500	–	–	$ 92.65
Swap(1)	500	–	–	$ 94.80
Swap(2)	1,000	–	–	$ 82.36
Sold Put	1,000	–	$ 55.00	–
Sold Put(1)	500	–	$ 55.00	–
Sold Put(1)	1,000	–	$ 58.00	–

(1) Financial contracts entered into during the second quarter of 2010.
(2) Financial contracts entered into subsequent to June 30, 2010.

Natural Gas:

	Daily Volumes MMcf/day	AECO CDN$/Mcf Purchased Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term					
Jul 1, 2010 – Oct 31, 2010					
Swap	23.7	–	–	–	$ 7.33
Swap	4.7	–	–	–	$ 5.60
Swap	4.7	–	–	–	$ 5.77
Purchased Call	9.5	$ 6.54	–	–	–
Jul 1, 2010 – Dec 31, 2010					
Put Spread	4.7	–	$ 5.28	$ 3.96	–
Put Spread	4.7	–	$ 5.44	$ 3.96	–
Put Spread	9.5	–	$ 5.59	$ 3.96	–
Put Spread	4.7	–	$ 5.70	$ 4.22	–
Jul 1, 2010 – 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
Nov 1, 2010 – Mar 31, 2011					
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(1)	9.5	$ 6.38	–	–	–
Sold Put	19.0	–	–	$ 4.48	–
Sold Put(1)	9.5	–	–	$ 3.96	–
Jan 1, 2011 – Mar 31, 2011					
Purchased Call	14.2	$ 6.38	–	–	–
Sold Put	9.5	–	–	$ 4.37	–
Sold Put	4.7	–	–	$ 4.03	–
Jul 1, 2010 – Oct 31, 2010					
Physical	2.0	–	–	–	$ 2.77

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

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 June 30, 2010 on the Fund's outstanding commodity derivative contracts at that time with all other variables held constant:

($ thousands)	Increase/(decrease) to after-tax net income: 25% decrease in forward prices	25% increase in forward prices
Crude oil derivative contracts	**$ 51,165**	**$ (44,586)**
Natural gas derivative contracts	**$ 13,173**	**$ (13,304)**

Electricity:

The Fund is subject to electricity price fluctuations and it manages this risk by entering into forward fixed rate electricity derivative contracts on a portion of its electricity requirements. The Fund's outstanding electricity derivative contracts as at July 28, 2010 are summarized below:

Term	Volumes MWh	Price CDN$ /MWh
July 1, 2010 – December 31, 2010	4.0	$ 77.50
July 1, 2010 – December 31, 2010	2.0	$ 68.75
July 1, 2010 – December 31, 2010	3.0	$ 49.50
July 1, 2010 – December 31, 2010	3.0	$ 52.25
July 1, 2010 – December 31, 2010	2.0	$ 49.00
July 1, 2010 – 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)	2.0	$ 50.00
January 1, 2012 – December 31, 2012(1)	3.0	$ 54.50

(1) Financial contracts entered into during the second quarter of 2010.
(2) Financial contracts entered into subsequent to June 30, 2010.

9. COMMITMENTS AND CONTINGENCIES

In conjunction with the Marcellus acquisition on September 1, 2009 the Fund has committed to pay 50% of the sellers' future drilling and completion costs up to an aggregate amount of US$246,600,000. Our outstanding commitment balance at June 30, 2010 is approximately US$208,726,000. We expect the remainder of the commitment will be incurred over the next four years.

Board of Directors

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

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

Robert B. Hodgins(3)(6)
Corporate Director
Calgary, Alberta

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

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

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

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

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

Harry B. Wheeler(5)(9)
Corporate Director
Calgary, Alberta

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

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

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

Officers

Gordon J. Kerr
President & Chief Executive Officer

Ian C. Dundas
Executive Vice President

Robert J. Waters
Senior Vice President & Chief Financial Officer

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

Ray J. Daniels
Vice President, Development Services & Oil Sands

Rodney D. Gray
Vice President, Finance

Dana W. Johnson
President, U.S. Operations

Lyonel G. Kawa
Vice President, Information Services

Robert A. Kehrig
Vice President, Resource Development

Jennifer F. Koury
Vice President, Corporate Services

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

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

Robert W. Symonds
Vice President, Canadian Operations

Kenneth W. Young
Vice President, Land

Jodine J. Jenson Labrie
Controller, Finance

Corporate Information

Operating Companies Owned by Enerplus Resources Fund
EnerMark Inc.
Enerplus Resources Corporation
Enerplus Commercial Trust
Enerplus Resources (USA) Corporation
FET Operational Partnership

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

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates Inc.
Dallas, Texas

Haas Petroleum Engineering Services, Inc.
Dallas, Texas

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

U.S. Office
Wells Fargo Center
1300, 1700 Lincoln Street
Denver, Colorado 80203

Telephone: 720.279.5500
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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
BOE(s)/day barrel of oil equivalent per day (6 Mcf of gas:1 BOE)
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
GORR gross overriding royalty
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
MMcfe million cubic feet equivalent
MMcf/day million cubic feet per day
MMcfe/day million cubic feet equivalent 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
SAGD steam assisted gravity drainage
WI percentage working interest ownership
WTI West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing purposes

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