THE ENERGY OF

enerPLUS

THIRD QUARTER REPORT

Nine months ended September 30, 2008

FINANCIAL AND OPERATING HIGHLIGHTS

Selected Financial Results (in Canadian dollars)	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Financial (000's)				
Cash Flow from Operating Activities	**$383,573**	$232,801	**$1,004,246**	$663,464
Cash Distributions to Unitholders[1]	**224,417**	163,110	**619,121**	483,388
Cash Withheld for Acquisitions and Capital Expenditures	**159,156**	69,691	**385,125**	180,076
Net Income	**465,773**	93,033	**699,397**	240,990
Debt Outstanding (net of cash)	**522,254**	649,829	**522,254**	649,829
Development Capital Spending	**163,215**	90,647	**377,485**	281,045
Acquisitions	**4,574**	1,755	**1,771,383**	269,149
Divestments	**502,489**	96	**504,697**	5,569
Actual Cash Distributions to Unitholders per Trust Unit	**$ 1.31**	$ 1.26	**$ 3.83**	$ 3.78
Financial per Weighted Average Trust Units[2]				
Cash Flow from Operating Activities	**$ 2.33**	$ 1.80	**$ 6.32**	$ 5.22
Cash Withheld for Acquisitions and Capital Expenditures	**0.97**	0.54	**2.42**	1.42
Net Income	**2.82**	0.72	**4.40**	1.90
Payout Ratio[3]	**59%**	70%	**62%**	73%
Selected Financial Results per BOE[4]				
Oil & Gas Sales[5]	**$ 73.62**	$ 49.64	**$ 72.44**	$ 49.89
Royalties	**(13.71)**	(9.28)	**(13.54)**	(9.38)
Commodity Derivative Instruments	**(6.82)**	1.00	**(5.19)**	0.63
Operating Costs	**(10.10)**	(9.61)	**(9.51)**	(9.32)
General and Administrative	**(1.50)**	(2.11)	**(1.66)**	(2.00)
Interest and Other Income and Foreign Exchange	**(1.46)**	(1.34)	**(1.23)**	(1.34)
Taxes	**(0.59)**	(0.70)	**(1.19)**	(0.46)
Restoration and Abandonment	**(0.54)**	(0.48)	**(0.52)**	(0.47)
Cash Flow from Operating Activities before changes in non-cash working capital	**$ 38.90**	$ 27.12	**$ 39.60**	$ 27.55
Weighted Average Number of Trust Units Outstanding Including Equivalent Exchangeable Limited Partnership Units (thousands)	**164,908**	129,373	**158,980**	127,025
Debt/Trailing 12 Month Cash Flow Ratio[6]	**0.4x**	0.7x	**0.4x**	0.7x

Selected Operating Results	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Average Daily Production				
Natural gas (Mcf/day)	**341,803**	251,264	**336,328**	263,884
Crude oil (bbls/day)	**34,119**	34,077	**34,295**	34,602
NGLs (bbls/day)	**4,557**	3,937	**4,660**	4,194
Total (BOE/day)	**95,644**	79,891	**95,010**	82,777
% Natural gas	**60%**	52%	**59%**	53%
Average Selling Price[5]				
Natural gas (per Mcf)	**$ 8.25**	$ 5.59	**$ 8.60**	$ 6.63
Crude oil (per bbl)	**110.63**	69.16	**103.85**	62.75
NGLs (per bbl)	**81.20**	50.79	**77.21**	49.26
US$ exchange rate	**0.96**	0.96	**0.98**	0.91
Net Wells drilled	**272**	101	**469**	177
Success Rate	**99%**	99%	**99%**	99%

(1) Calculated based on distributions paid or payable.
(2) Based on weighted average trust units outstanding for the period, including the exchangeable limited partnership units assumed through the Focus Energy Trust acquisition.
(3) Calculated as Cash Distributions to Unitholders divided by Cash Flow from Operating Activities. See "Non-GAAP Measures" in the following Management's Discussion and Analysis.
(4) Non-cash amounts have been excluded.
(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(6) Including the trailing 12 month cash flow of Focus Energy Trust.

Trust Unit Trading Summary

for the three months ended September 30, 2008	TSX – ERF.un (CDN$)	NYSE – ERF (US$)
High	$48.15	$47.47
Low	$35.57	$33.64
Close	$38.86	$37.19

2008 Cash Distributions Per Trust Unit

Payment Month	CDN$	US$
First Quarter Total	**$1.26**	**$1.23**
Second Quarter Total	**$1.26**	**$1.25**
July	$0.42	$0.42
August	0.42	0.39
September	0.47	0.45
Third Quarter Total	**$1.31**	**$1.26**
Total Year-to-Date	**$3.83**	**$3.74**

The following President's Message contains forward-looking information and statements. See "Forward-Looking Information and Statements" in the following Management's Discussion and Analysis, which disclaimer applies to this President's Message. All dollar amounts in this President's Message are in Canadian dollars unless otherwise indicated. The following also contains estimates of "contingent resources". See "Information Regarding Contingent Resource Estimates" in the following Management's Discussion and Analysis" which applies to such contingent resource disclosure.

PRESIDENT'S MESSAGE

While the dramatic downturn in commodity prices and the turmoil in the global financial markets have created an environment of unprecedented volatility, Enerplus continued to execute on a number of our business strategies throughout the third quarter and is well positioned to capitalize on opportunities given the current market conditions. The closing of the sale of our Joslyn oil sands lease for net proceeds of $502 million has greatly enhanced our financial flexibility and put us in an enviable position with regard to our balance sheet strength. Our debt to trailing 12 month cash flow ratio is currently 0.4x, one of the lowest in our sector. I am also pleased to report that we have achieved another milestone regarding our operated Kirby oil sands project by filing the regulatory application slightly earlier than planned for Phase 1 development of 10,000 bbls/day of bitumen production. These activities have not only helped us to manage our business in the short-term, but are also expected to provide us with the ability to grow our business for the long-term.

During the quarter, we recorded cash flow of $383.6 million ($2.33 per unit) on the sale of our crude oil and natural gas production, slightly higher than the cash flows earned during the second quarter of 2008. Actual cash distributions paid to unitholders were $1.31 per unit, up 4% from the second quarter. Our payout ratio was approximately 59% during the period. When we include our development capital expenditures, our adjusted payout ratio was 102% for the quarter.

Daily production during the third quarter averaged 95,644 BOE/day, lower than expected due to delays in the execution of our capital program caused by wet weather and optimization activity as well as unplanned downtime at a number of non-operated facilities. The majority of the production shortfall was related to our development program at Shackleton where higher than normal rainfall in both the second and third quarters hampered our ability to execute our shallow gas program. As well, we undertook a review of our completion techniques at Shackleton in order to optimize production from additional zones delaying the tie-in of a number of wells in the area.

The level of commodity price volatility experienced recently is unlike any we have seen in recent history. West Texas Intermediate crude oil prices fell 37% from a high of US$145.29/bbl to US$91.15/bbl during the third quarter and have continued to dramatically decline since September 30, 2008. Concerns over rising inventories due to demand destruction from the higher prices and the threat of a global economic slowdown grew throughout the quarter, driving oil prices lower in response. Natural gas prices also fell close to 50% from their peak during the same period. This commodity price downturn, combined with the current uncertainty in the capital markets, has reinforced our belief in the importance of maintaining strong financial flexibility. As a result, we have reduced our monthly cash distribution level from $0.47/unit to $0.38/unit effective with the November 2008 distribution payment. We are also reducing our overall capital spending plans for 2008 by $35 million (6%) to $545 million for the year. However, we continue to invest in long-term growth opportunities. Our revised $545 million capital expenditure guidance includes an additional $20 million of land acquisitions over our original plans which do not provide near-term production or cash flow, but which we expect will help build development opportunities for the future. Looking ahead to 2009, given the lower commodity price environment we currently face as well as the uncertainty in the financial and credit markets, we are expecting our 2009 capital spending to be moderately lower than our 2008 spending. We expect to provide detailed operational and production guidance for 2009 in mid-December.

As a result of our adjustment in capital spending and lower than expected third quarter production, we are lowering our 2008 average annual production guidance slightly to 96,000 BOE/day and adjusting our anticipated exit rate from 100,000 BOE/day to 98,500 BOE/day. Our operating costs are also impacted by the reduced production forecast as well as by continued cost increases related to our optimization activities in the U.S. As a result we are now estimating full year 2008 operating costs to be $9.50/BOE versus our previous guidance of $9.00/BOE. This increase is partially offset by lower than expected general and administrative costs primarily due to lower expenses associated with long-term compensation plans. We now expect our 2008 general and administrative cash expenses to be approximately $2.00/BOE, a reduction of $0.20/BOE.

2008 Production and Development Activity

	Three months ended September 30,				Nine months ended September 30,			
	Production Volumes	Capital Spending	Wells Drilled*		Production Volumes	Capital Spending	Wells Drilled*	
Play Type	(BOE/day)	($ millions)	Gross	Net	(BOE/day)	($ millions)	Gross	Net
Shallow Gas & CBM	23,479	$ 55.0	254	235	23,183	$101.3	471	394
Crude Oil Waterfloods	16,904	19.7	20	18	16,061	47.6	42	28
Deep Tight Gas	15,730	11.0	22	3	14,431	42.8	52	8
Bakken/Tight Oil	10,118	45.0	3	2	10,778	78.0	11	8
Other Conventional Oil & Gas	29,413	26.7	78	14	30,557	67.6	157	31
Total Conventional	**95,644**	**157.4**	**377**	**272**	**95,010**	**337.3**	**733**	**469**
Oil Sands								
Kirby	–	5.0	–	–	–	29.5	–	–
Other Oil Sands	–	0.8	–	–	–	10.7	–	–
Total Oil Sands	**–**	**5.8**	**–**	**–**	**–**	**40.2**	**–**	**–**
Total	**95,644**	**$163.2**	**377**	**272**	**95,010**	**$377.5**	**733**	**469**

* Drilling totals do not include delineation wells at Kirby or service wells

Drilling success rate year-to-date: 99%

Development capital spending was $163.2 million in the third quarter and $377.5 million for year-to-date. Our activities have included both oil and natural gas projects however a greater concentration of spending was directed at natural gas opportunities during the quarter. A total of 272 net wells were drilled in the third quarter, the majority of which were at Shackleton, our largest and most profitable shallow natural gas property which is located in southwest Saskatchewan.

Our crude oil activities were concentrated on our waterflood properties and our Bakken oil property in the U.S. In Alberta, a key waterflood development project was undertaken at our Giltedge property where we drilled 13 wells and have identified further development potential associated with the significant amount of oil remaining in this pool. In the U.S. we also continued our refrac program and our third well per section drilling program on our Sleeping Giant field. We continue to be encouraged by the performance from this field and plan to continue our drilling program into 2009. As a result of this activity, we expect our capital spending to increase from approximately $60 million to between $70 million and $80 million in this area in 2008. The aggressive pace of Bakken development in Montana and North Dakota continues to be a concern as pipeline capacity has not kept pace with production growth. Through careful management of our inventory volumes, we have not faced any significant production curtailments to date, however we have seen an increase in transportation differentials which have impacted our netbacks. We continue to monitor the situation closely.

Overall, our investment activities are aimed at helping to replace our annual production volumes and establishing future development opportunities for the years to come. During the quarter, we invested approximately $43 million primarily on pre-investment spending which included the purchase of land in the Montney region of Alberta and British Columbia and the Bakken region of southeast Saskatchewan and oil sands project work. Year-to-date, our pre-investment spending has totaled approximately $87 million, approximately one half of which has been invested in oil sands and the majority of the remainder being invested in undeveloped land.

Safety incidents were down compared to the first half of this year and as a result recordable and lost time injury frequency rates improved for both employees and contractors. We attribute our over-all safety performance success to enhanced hazard awareness combined with a greater level of safety communication with our contractors and employees.

Oil Sands Activities

Enerplus achieved another milestone during the quarter on our operated Kirby steam assisted gravity drainage ("SAGD") Oil Sands project by filing our regulatory application for the first phase of development ("Phase 1") with the Energy Resources Conservation Board and Alberta Environment on September 26, 2008, slightly earlier than expected. We plan to continue to advance the Kirby project to be in a position to present this project for a sanctioning decision by our Board of Directors once we receive regulatory approval and have completed additional engineering design planning. We expect to be in this position by the fourth quarter of 2009. We are also continuing to delineate the lease to set up expansion of this project over time.

Phase 1 of the Kirby lease consists of a 10,000 bbl/day SAGD development that we expect to produce bitumen for approximately 25 years. We tentatively plan to begin construction in 2009 following regulatory approval. First steam is anticipated in late 2011, first production is expected in 2012 and full commercial production volumes of 10,000 bbls/day are expected in 2013. Our current estimate of the capital costs associated with construction of Phase 1 is approximately $400 million (2008 dollars).

Our 2007/08 winter drilling program was focused on delineating the northern block of the lease which is where Phase I will be located. Based on the results of this delineation work, our third party reserve engineers have confirmed a best estimate contingent resource of approximately 414 million barrels, a 70% increase from the original resource estimate completed when we purchased the lease in the spring of 2007. The following table summarizes the contingent resource estimate for the Kirby Lease:

Northern Area Wabiskaw D (Project area)	118 million barrels
Northern Area McMurray	191 million barrels
Central and Southern Areas	105 million barrels
Total Kirby Lease Contingent Resource Estimate	414 million barrels

For additional information relating to contingent resource estimates, see "Information Regarding Contingent Resource Estimates" in the following Management's Discussion and Analysis. As well, for additional information regarding our Kirby Oil Sands project, see pages 16 and 17 of our Annual Information Form for the year ended December 31, 2007, a copy of which is available on our SEDAR profile at www.sedar.com and which also forms part of our Form 40-F for the year ended December 31, 2007 filed with the SEC, a copy of which is available at www.sec.gov.

Looking Ahead

We are experiencing unprecedented volatility in the commodity, credit and equity markets on a global scale not seen in decades. We are fortunate to be in a position of strength not only due to the opportunities we have within our asset base, but also the financial flexibility we have with over $1.1 billion of available credit capacity. We will continue to invest in our assets and will evaluate opportunities for acquisitions in this attractive market, but we will do so judiciously. We believe that in tumultuous times like these, it is in our best interest to maintain our financial flexibility by controlling costs and managing our cash flows. I believe we will not only weather these uncertain times as we have previously in our 22 year history but that we will attract new highly skilled people and capture opportunities which will allow us to further build and strengthen our company.

I am also pleased to recognize two new additions to our executive team – Mr. Ken Young, Vice-President Land and Mr. Robert Kehrig, Vice-President Resource Development. Mr. Young is a new addition to the Enerplus organization and is a seasoned Land Professional with over 25 years of direct land experience. His primary focus will be on our Canadian operations. Mr. Kehrig joined Enerplus in 2002 as Manager of Business Development and has been a key contributor in all of our acquisitions activity over that period. In his new role, he will be responsible for the coordination of our efforts to identify and capture new resource opportunities within our existing asset base and outside. I believe these positions are essential to the future success of our business as we look to create value through internally-generated growth.

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

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

The following discussion and analysis of financial results is dated November 6, 2008 and is to be read in conjunction with:

- the audited consolidated financial statements as at and for the years ended December 31, 2007 and 2006; and
- the unaudited interim consolidated financial statements as at and for the three and nine months ended September 30, 2008 and 2007.

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 for our disclaimer on forward-looking information and statements.

Non-GAAP Measures

Throughout the MD&A we use the term "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 are measures prescribed by GAAP which appear on our consolidated statements of cash flows. The term "payout ratio" does 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 on cash flow, cash distributions and payout ratio.

Overview

Cash flow from operating activities for the third quarter increased to $383.6 million from $364.5 million in the second quarter, largely due to decreases in our non-cash operating working capital. Our payout ratio was 59% for the quarter and 62% year to date. Commodity prices remained strong for most of the quarter however the sharp decline in prices towards the end of the quarter resulted in $280.7 million of non-cash gains on our commodity derivative instruments. We received net proceeds of $502.0 million for the Joslyn disposition on July 31, 2008 which was used to pay down debt. At September 30, 2008 our balance sheet remains strong with a trailing 12 month debt to cash flow ratio of 0.4x, leaving us with available capacity of over $1.1 billion on our $1.4 billion credit facility.

Our year-to-date development capital spending totaled $377.5 million and is behind schedule mainly due to weather and project delays at both operated and non-operated properties. Based on our year-to-date spending and project deferrals and cancellations in the fourth quarter we are revising our annual development capital guidance to $545 million from $580 million, based on a $55 million reduction in our conventional program which is partially offset by $20 million of additional land acquisitions.

Production for the quarter was 95,644 BOE/day, slightly lower than expected due to a combination of development delays and unplanned facility downtime. Given our year-to-date results and revised capital program we are decreasing our annual average production guidance from 98,000 BOE/day to 96,000 BOE/day and our 2008 exit rate guidance from 100,000 BOE/day to 98,500 BOE/day. In conjunction with the revised production estimates we are increasing our operating cost guidance from $9.00/BOE to $9.50/BOE however our general and administrative expense guidance is being revised downwards to $2.00/BOE from $2.20/BOE primarily due to decreased expenses associated with our long-term compensation plans.

The significant decrease in commodity prices combined with the current uncertainty in the capital markets has reinforced our belief in the importance of maintaining strong financial flexibility therefore we have lowered our monthly cash distribution to $0.38 per unit from $0.47 per unit effective November 20, 2008.

Results of Operations

Production

Production in the third quarter of 2008 averaged 95,644 BOE/day, a decrease of 5% from 100,188 BOE/day in the second quarter of 2008. The decrease for the quarter was primarily due to capital project delays and unplanned downtime at our non-operated plants including Brooks South, K3, McMahon and Elmworth. We also experienced tie-in delays at our operated Shackleton property during the quarter as we were assessing alternative well completion techniques. As a result of these capital delays and unplanned downtime, we are reducing our annual average production guidance from 98,000 BOE/day to 96,000 BOE/day and our 2008 exit rate from 100,000 BOE/day to 98,500 BOE/day.

For the three and nine months ended September 30, 2008 production increased 20% and 15% respectively, compared to the same periods in 2007. These increases were primarily due to the additional production from the Focus Energy Trust ("Focus") assets acquired on February 13, 2008.

Average production volumes for the three and nine months ended September 30, 2008 and 2007 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Daily Production Volumes	2008	2007	% Change	2008	2007	% Change
Natural gas (Mcf/day)	341,803	251,264	36%	336,328	263,884	27%
Crude oil (bbls/day)	34,119	34,077	–%	34,295	34,602	(1)%
Natural gas liquids bbls/day)	4,557	3,937	16%	4,660	4,194	11%
Total daily sales (BOE/day)	95,644	79,891	20%	95,010	82,777	15%

Pricing

The prices received for our natural gas and crude oil production have a direct impact on our earnings, cash flow and financial condition. The following table compares our average selling prices, net of transportation costs, for the three and nine months ended September 30, 2008 and 2007. It also compares the benchmark price indices for the same periods:

	Three months ended September 30,			Nine months ended September 30,		
Average Selling Price[(1)]	2008	2007	% Change	2008	2007	% Change
Natural gas (per Mcf)	$ 8.25	$ 5.59	48%	$ 8.60	$ 6.63	30%
Crude oil (per bbl)	$110.63	$69.16	60%	$103.85	$62.75	65%
Natural gas liquids (per bbl)	$ 81.20	$50.79	60%	$ 77.21	$49.26	57%
Per BOE	$ 73.62	$49.64	48%	$ 72.44	$49.89	45%
Average Benchmark Pricing						
AECO natural gas – monthly index (CDN$/Mcf)	$ 9.25	$ 5.61	65%	$ 8.58	$ 6.81	26%
AECO natural gas – daily index (CDN$/Mcf)	$ 7.75	$ 5.18	50%	$ 8.62	$ 6.55	32%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	$ 10.09	$ 6.13	65%	$ 9.65	$ 6.88	40%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	$ 10.51	$ 6.39	64%	$ 9.85	$ 7.56	30%
WTI crude oil (US$/bbl)	$117.98	$75.38	57%	$113.29	$66.23	71%
WTI crude oil CDN$ equivalent (CDN$/bbl)	$122.90	$78.52	57%	$115.60	$72.78	59%
CDN$/US$ exchange rate	0.96	0.96	–%	0.98	0.91	8%

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

During the quarter the AECO natural gas price fell approximately 51% from a high of $11.83/Mcf on July 1 to $6.10/Mcf at the end of September. This sharp decrease was triggered by significant increases in U.S. natural gas production and reduced demand caused by moderate cooling loads and a weakening economy.

We realized an average price on our natural gas of $8.25/Mcf during the three months ended September 30, 2008, an increase of 48% from $5.59/Mcf for the same period in 2007. For the nine months ended September 30, 2008 we realized a 30% increase in our average price of $8.60/Mcf compared to the same period in 2007. The majority of our natural gas sales are priced with reference to the monthly or daily AECO indices. The 30% increase for the nine month period is comparable to the increases experienced by the AECO indices over the same period. However, the increases in our current quarter realized gas prices over the same period in 2007 were lower than the increases in the AECO indices over the same periods due to lower prices received for our U.S. natural gas production resulting from excess supply in the region and the fact that a small portion of our Canadian natural gas sold at a discount to the August month index with the sharp decline in prices during the month of July.

Crude oil prices fell 39%, from US$147.27/bbl to US$90.51/bbl, during the third quarter in response to demand destruction as the threat of a global economic slowdown grew. The average price we received for our crude oil during the three months ended September 30, 2008 increased 60% to $110.63/bbl compared to $69.16/bbl during the same period in 2007. Similarly, the West Texas Intermediate ("WTI") crude oil benchmark price, in Canadian dollars, increased 57% from the corresponding period in 2007. For the nine months ended September 30, 2008 our crude oil price increased 65% to $103.85/bbl, while the WTI benchmark, in Canadian dollars, increased 59%. The narrowing of the market differential for our heavy oil production was the main contributor to the higher year-over-year price increase received on our crude oil relative to the increase in WTI.

For the third quarter of 2008 the Canadian dollar remained unchanged against the U.S. dollar relative to the same period in 2007. The Canadian dollar strengthened against the U.S. dollar during the nine months ended September 30, 2008 compared to the same period in 2007. As most of our crude oil and natural gas sales are priced in reference to U.S. dollar denominated benchmarks, this movement in the exchange rate reduced the Canadian dollar prices that we would have otherwise realized.

Since the end of the third quarter there has been a dramatic reduction in crude oil prices in response to the global credit crisis and concerns over the health of economies around the world. The impact of lower crude oil prices has been partially offset by a weaker Canadian dollar which helps energy producers such as Enerplus. As at October 28, 2008 crude oil prices (WTI) had fallen to U.S. $62.73/bbl from $100.64/bbl at September 30, 2008 partially offset by a 22% change in the CDN$/US$ exchange rate to 0.77.

Price Risk Management

We continue to evolve our price risk management framework in response to the increased volatility of the commodity price environment. Consideration is given to our overall financial position together with the economics of our development capital program and potential acquisitions. Consideration is also given to the upfront and potential costs of our risk management program as we seek to limit our exposure to price downturns. Hedge positions for any given term are transacted across a range of prices and time.

Considering all financial contracts transacted as of October 28, 2008, we have protected a portion of our natural gas price risk through to October 31, 2009 and a portion of our crude oil price risk through to December 31, 2009. We have also taken steps to protect our exposure to rising electricity costs for a portion of our consumption in the Alberta power market through to December 31, 2010. See Note 9 for a list of our current price risk management positions.

The following is a summary of the financial contracts in place at October 28, 2008, expressed as a percentage of our forecasted net production volumes:

	Natural Gas (CDN$/Mcf)			Crude Oil (US$/bbl)	
	October 1, 2008 – October 31, 2008	November 1, 2008 – March 31, 2009	April 1, 2009 – October 31, 2009	October 1, 2008 – December 31, 2008	January 1, 2009 – December 31, 2009
Floor Price (puts)	$7.09	$ 9.20	$9.01	$72.09	$ 98.08
% (net of royalties)	26%	23%	8%	35%	26%
Fixed Price (swaps)	$7.44	$ 9.35	$7.86	$79.97	$100.05
% (net of royalties)	21%	3%	2%	19%	2%
Capped Price (calls)	$8.25	$11.60	–	$85.48	$ 92.98
% (net of royalties)	26%	11%	–	22%	11%

Based on weighted average price (before premiums), estimated average annual production of 96,000 BOE/day and assuming a royalty rate of 19% in 2008 and 22% in 2009.

Accounting for Price Risk Management

During the third quarter of 2008 our price risk management program incurred cash losses of $18.8 million on our natural gas contracts and $41.2 million on our crude oil contracts, compared to cash gains of $14.1 million and cash losses of $6.7 million respectively during the third quarter of 2007. For the nine months ended September 30, 2008 we experienced cash losses of $30.6 million on our natural gas contracts and cash losses of $104.4 million on our crude oil contracts, compared to a gain of $12.8 million and a gain of $1.4 million respectively for the same period in 2007. The increase in cash losses for the three and nine months ended September 30, 2008 compared to the corresponding periods in 2007 was the result of commodity prices rising above our swap and sold call positions. As noted above, commodity prices have continued to decrease since the end of the third quarter which we believe will result in improved performance of our price risk management program in the fourth quarter of 2008.

The fair value of our commodity derivative instruments was impacted by the significant decrease in forward commodity prices at September 30, 2008 compared to June 30, 2008. At September 30, 2008 the fair value of our natural gas derivative instruments represented a gain of $14.0 million and the fair value of our crude oil derivative instruments represented a loss of $22.4 million. In comparison, at June 30, 2008 the fair value of our natural gas and crude oil derivative instruments represented losses of $89.9 million and $199.2 million respectively. The change in fair value of our commodity derivative instruments during the third quarter of 2008 resulted in unrealized gains of $280.7 million which was comprised of $103.9 million for natural gas and $176.8 million for crude oil. For the nine months ended September 30, 2008 the change in fair value of our commodity derivative instruments resulted in unrealized gains of $5.9 million for natural gas and $34.4 million for crude oil. See Note 9 for details.

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

Risk Management Costs	Three months ended September 30,		Three months ended September 30,	
($ millions, except per unit amounts)	2008		2007	
Cash (losses)/gains:				
Natural gas	$ (18.8)	$ (0.60)/Mcf	$ 14.1	$ 0.61/Mcf
Crude oil	(41.2)	(13.13)/bbl	(6.7)	(2.14)/bbl
Total cash (losses)/gains	$ (60.0)	$ (6.82)/BOE	$ 7.4	$ 1.00/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – natural gas	$ 103.9	$ 3.30/Mcf	$ 2.8	$ 0.12/Mcf
Change in fair value – crude oil	176.8	56.30/bbl	(6.6)	(2.12)/bbl
Total non-cash gains/(losses)	$ 280.7	$ 31.90/BOE	$ (3.8)	$ (0.51)/BOE
Total gains	$ 220.7	$ 25.08/BOE	$ 3.6	$ 0.49/BOE

Risk Management Costs	Nine months ended September 30,		Nine months ended September 30,	
($ millions, except per unit amounts)	2008		2007	
Cash (losses)/gains:				
Natural gas	$ (30.6)	$ (0.33)/Mcf	$ 12.8	$ 0.18/Mcf
Crude oil	(104.4)	(11.11)/bbl	1.4	0.15/bbl
Total cash (losses)/gains	$(135.0)	$ (5.19)/BOE	$ 14.2	$ 0.63/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – natural gas	$ 5.9	$ 0.06/Mcf	$ 7.6	$ 0.11/Mcf
Change in fair value–crude oil	34.4	3.66/bbl	(25.8)	(2.74)/bbl
Total non-cash gains/(losses)	$ 40.3	$ 1.55/BOE	$(18.2)	$ (0.81)/BOE
Total (losses)	$ (94.7)	$ (3.64)/BOE	$ (4.0)	$ (0.18)/BOE

Cash Flow Sensitivity

The sensitivities below reflect the estimated impact on cash flow per trust unit for the remaining quarter of 2008 and include the commodity contracts described in Note 9 as well as the impact of 2008 forward market prices as at October 28, 2008. We have not finalized our budget or plans for 2009 and consequently 2009 sensitivities are not available. To the extent the market price of crude oil and natural gas change significantly from the October 28, 2008 levels, the sensitivities will no longer be relevant as the effect of our commodity contracts will change.

Sensitivity Table	Estimated Effect on Fourth Quarter 2008 Cash Flow per Trust Unit[1]
Change of $0.15 per Mcf in the price of AECO natural gas	$0.02
Change of US$1.00 per barrel in the price of WTI crude oil	$0.01
Change of 1,000 BOE/day in production	$0.02
Change of $0.01 in the US$/CDN$ exchange rate	$0.03
Change of 1% in interest rate	$0.01

(1) Assumes constant working capital and 165,197,000 units outstanding.

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

Revenues

Crude oil and natural gas revenues were lower during the third quarter of 2008 compared to the second quarter of 2008 due to decreased commodity prices and lower production.

Crude oil and natural gas revenues for the three months ended September 30, 2008 were $647.8 million ($654.6 million, net of $6.8 million transportation) compared to $364.8 million ($370.2 million, net of $5.4 million transportation) for the same period in 2007. For the nine months ended September 30, 2008 revenues were $1,885.9 million ($1,906.1 million, net of $20.2 million transportation) compared to $1,127.3 million ($1,144.0 million, net of $16.7 million transportation) during the same period in 2007. Revenues have increased compared to 2007 due to higher commodity prices and increased production resulting from the Focus acquisition which closed on February 13, 2008.

The following table summarizes the changes in sales revenue:

Analysis of Sales Revenue[1]

($ millions)	Crude Oil	NGLs	Natural Gas	Total
Quarter ended September 30, 2007	$216.8	$18.4	$129.6	$ 364.8
Price variance[1]	130.2	12.7	86.8	229.7
Volume variance	0.3	2.9	50.1	53.3
Quarter ended September 30, 2008	**$347.3**	**$34.0**	**$266.5**	**$ 647.8**

($ millions)	Crude Oil	NGLs	Natural Gas	Total
Year-to-date ended September 30, 2007	$592.7	$56.4	$478.2	$1,127.3
Price variance[1]	386.3	35.7	190.7	612.7
Volume variance	(3.1)	6.5	142.5	145.9
Year-to-date ended September 30, 2008	**$975.9**	**$98.6**	**$811.4**	**$1,885.9**

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

Other Income

Other income for the three and nine months ended September 30, 2008 was $0.3 million and $15.8 million respectively, compared to $0.1 million and $14.6 million for the same periods in 2007. The first nine months of 2008 includes a gain of $8.3 million on the sale of certain marketable securities and interim receipts from our business interruption insurance of $6.4 million related to the Giltedge fire. During the first quarter of 2007 we realized a gain of $14.1 million on the sale of marketable securities.

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three and nine months ended September 30, 2008 royalties were $120.6 million and $352.5 million respectively, compared to $68.2 million and $211.9 million for the same periods in 2007. Royalties as a percentage of oil and gas sales net of transportation have been approximately 19% during these periods. The increases in royalties in 2008 are the result of higher commodity prices and increased production. For the remainder of 2008 we expect royalties to continue to be approximately 19% of oil and gas sales, net of transportation.

In October 2007 the Alberta government announced a 'New Royalty Framework' ("NRF") which will be effective January 1, 2009 and is expected to increase our royalties as a percentage of oil and gas sales. In the context of an annualized forward market outlook of US$70.00/bbl crude oil and $8.00/Mcf natural gas, and relative to Enerplus' current properties and production profile in Alberta, we estimate the NRF will increase our average 2009 royalty rate to approximately 22% of oil and gas sales, net of transportation costs. If commodity prices are higher than such estimates, we expect our average royalty rate for 2009 to increase as well. Further information on the NRF can be found on the Alberta government's website at www.gov.ab.ca.

Operating Expenses

Operating expenses for the third quarter of 2008 increased to $89.8 million ($10.21/BOE) from $86.0 million ($9.43/BOE) during the second quarter of 2008 due to lower production volumes along with higher repairs and maintenance and chemical and supply costs.

Operating expenses for the three months ended September 30, 2008 were $89.8 million ($10.21/BOE) compared to $71.6 million ($9.73/BOE) for the third quarter of 2007. For the nine months ended September 30, 2008 operating expenses were $247.8 million ($9.52/BOE) compared to $210.3 million ($9.31/BOE) for the same period in 2007. This year-over-year increase is due to additional service rig activity related to our U.S. optimization program and higher than expected costs for repairs and maintenance, labour, and chemicals and supplies.

Based on our year to date results and our revised 2008 production expectations we are increasing our annual operating expense guidance from $9.00/BOE to $9.50/BOE.

General and Administrative Expenses ("G&A")

During the third quarter of 2008 G&A expenses were $1.70/BOE compared to $1.90/BOE for the second quarter of 2008.

G&A expenses for the three months ended September 30, 2008 were $14.9 million ($1.70/BOE) compared to $17.7 million ($2.41/BOE) for the third quarter of 2007. G&A expenses totaled $48.7 million ($1.87/BOE) for the nine months ended September 30, 2008 compared to $51.5 million ($2.28/BOE) for the same period in 2007. G&A expenses have decreased year over year mainly due to lower long-term incentive plan expenses. However, higher production volumes during 2008 which are attributable to the Focus acquisition have helped to reduce G&A costs per BOE.

We do not expect our long-term compensation expense to change over the next quarter, therefore we are lowering our annual guidance for G&A expenses from $2.20/BOE to $2.00/BOE for the year.

For the three and nine months ended September 30, 2008 our G&A expenses included non-cash charges of $1.8 million ($0.20/BOE) and $5.4 million ($0.21/BOE) respectively, compared to $2.2 million ($0.30/BOE) and $6.4 million ($0.28/BOE) for the same periods in 2007. These amounts relate solely to our trust unit rights incentive plan and are determined using a binomial lattice option-pricing model. See Note 8 for further details.

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

General and Administrative Costs	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2008**	2007	**2008**	2007
Cash	**$13.1**	$15.5	**$43.3**	$45.1
Trust unit rights incentive plan (non-cash)	**1.8**	2.2	**5.4**	6.4
Total G&A	**$14.9**	$17.7	**$48.7**	$51.5
(Per BOE)	**2008**	2007	**2008**	2007
Cash	**$1.50**	$2.11	**$1.66**	$2.00
Trust unit rights incentive plan (non-cash)	**0.20**	0.30	**0.21**	0.28
Total G&A	**$1.70**	$2.41	**$1.87**	$2.28

Interest Expense

Interest expense includes interest on long-term debt, the premium amortization on our US$175 million senior unsecured notes, unrealized gains and losses resulting from the change in fair value of our interest rate swaps as well as the interest component on our cross currency interest rate swap ("CCIRS"). See Note 6 for further details.

Interest on long-term debt was $8.8 million for the third quarter of 2008 compared to $10.4 million for the same period in 2007. Lower year over year average debt resulting from the July 31, 2008 Joslyn disposition is the primary reason for the decrease. For the nine months ended September 30, 2008 interest on long-term debt totaled $35.1 million compared to $29.8 million for the same period in 2007. This increase is due to higher average outstanding indebtedness and higher interest rates for the nine months ended September 30, 2008 over the same period in 2007.

For the three and nine months ended September 30, 2008 we recorded non-cash interest gains of $1.6 million for both periods compared to gains of $4.0 million and $3.4 million for the same periods in 2007. The changes in the fair value of our interest rate swaps and CCIRS that result from movements in forward market interest rates cause non-cash interest to fluctuate between periods.

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

Interest Expense	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2008**	2007	**2008**	2007
Interest on long-term debt	**$ 8.8**	$10.4	**$35.1**	$29.8
Non-cash interest gain	**(1.6)**	(4.0)	**(1.6)**	(3.4)
Total Interest Expense	**$ 7.2**	$ 6.4	**$33.5**	$26.4

At September 30, 2008 approximately 34% of our debt was based on fixed interest rates while 66% had floating interest rates. In comparison, at September 30, 2007 approximately 20% of our debt was based on fixed interest rates and 80% was floating.

Capital Expenditures

Development capital spending for the three and nine months ended September 30, 2008 was $163.2 million and $377.5 million respectively, compared to $90.6 million and $281.0 million during the same periods in 2007. The increased spending levels in 2008 are largely due to our expanded asset base resulting from the Focus acquisition and stronger commodity prices. In addition our 2008 development capital expenditures include approximately $20 million of completed incremental land acquisitions over original budget amounts as we look to increase our efforts on resource capture in strategic areas. For the nine months ended September 30, 2008 we have achieved a 99% drilling success rate on 469 net wells.

Overall our 2008 development capital program is behind schedule mainly due to weather and project delays primarily in our shallow natural gas program. Based on our year-to-date spending and project deferrals and cancellations in the fourth quarter we are revising our annual development capital guidance to $545 million from $580 million, based on a $55 million reduction in our conventional program which is partially offset by the $20 million we have spent on additional land acquisitions. The reduction and reallocation of expenditures within our 2008 development capital program has modestly lowered our 2008 average annual production and exit rate expectations.

Corporate acquisitions for the nine months ended September 30, 2008 totaled approximately $1.7 billion and relate to the Focus acquisition which closed February 13, 2008 (refer to Note 4 for further details). Property dispositions for the three months ended September 30, 2008 relate to the Joslyn disposition which closed on July 31, 2008.

Property acquisitions for the three and nine months ended September 30, 2008 were $4.6 million and $13.9 million respectively, compared to $1.8 million and $269.1 million for the same periods in 2007. Property acquisitions in 2007 included the purchase of our Jonah and Kirby assets in the first and second quarter of 2007 respectively.

Total net capital expenditures for 2008 and 2007 are outlined below:

Capital Expenditures	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2008**	2007	**2008**	2007
Development expenditures	**$ 131.7**	$72.1	**$ 299.9**	$232.3
Plant and facilities	**31.5**	18.5	**77.6**	48.7
Development Capital	**163.2**	90.6	**377.5**	281.0
Office	**2.4**	1.7	**6.0**	4.6
Sub-total	**165.6**	92.3	**383.5**	285.6
Property acquisitions(1)	**4.6**	1.8	**13.9**	269.1
Corporate acquisitions	**–**	–	**1,757.5**	–
Capital Expenditures	**170.2**	94.1	**2,154.9**	554.7
Property dispositions(1)	**(502.5)**	(0.1)	**(504.7)**	(5.5)
Total Net Capital Expenditures	**$(332.3)**	$94.0	**$1,650.2**	$549.2
Funding of Capital Expenditures				
Capital Expenditures financed with cash flow	**$ 159.2**	$69.7	**$ 385.1**	$180.1
Capital Expenditures financed with debt and equity	**11.0**	24.4	**1,769.8**	374.6
Total Capital Expenditures	**$ 170.2**	$94.1	**$2,154.9**	$554.7

(1) Net of post-closing adjustments.

Oil Sands

Our oil sands development projects have not commenced commercial production. As a result all associated costs inclusive of acquisition expenditures, development capital spending, salaries and benefits, engineering and planning, net of revenues generated, are capitalized and excluded from our depletion calculation. At September 30, 2008 capitalized costs life-to-date for our oil sands development were $246.0 million compared to $351.1 million at June 30, 2008, prior to our disposition of Joslyn on July 31, 2008 for cash consideration of $502.0 million after transaction costs.

During the third quarter of 2008 we capitalized costs of $4.4 million associated with advancing our regulatory application for our Kirby project, which we successfully filed on September 26, 2008.

We continue to hold an interest in Laricina Energy Ltd., a private company with significant resources in the Alberta oil sands. This interest represents approximately 12% of Laricina's outstanding equity.

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

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves.

For the three months ended September 30, 2008, DDA&A increased to $18.32/BOE compared to $15.78/BOE during the corresponding period in 2007. For the nine months ended September 30, 2008 DDA&A increased to $18.19/BOE compared to $15.58/BOE during the corresponding period in 2007. The increase is attributable to additional PP&E and production from the Focus acquisition.

No impairment of the Fund's assets existed at September 30, 2008 using year-end reserves updated for acquisitions, divestitures and management's estimates of future prices.

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 the Fund's balance sheet are estimated by management based on the Fund's 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.

The Fund has estimated the net present value of its total asset retirement obligations to be approximately $203.8 million at September 30, 2008 compared to $165.7 million at December 31, 2007. The increase of $38.1 million relates primarily to the Focus acquisition. See Note 3.

The following chart compares the amortization of the asset retirement cost, accretion of the asset retirement obligation and asset retirement obligations settled during the period:

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2008**	2007	**2008**	2007
Amortization of the asset retirement cost	**$4.9**	$3.4	**$14.7**	$ 6.9
Accretion of the asset retirement obligation	**3.1**	1.7	**8.7**	5.0
Total Amortization and Accretion	**$8.0**	$5.1	**$23.4**	$11.9
Asset Retirement Obligations Settled	**$4.7**	$3.5	**$13.5**	$10.7

The timing of actual asset retirement costs will differ from the timing of amortization and accretion charges. Actual asset retirement costs will be incurred over the next 66 years with the majority between 2038 and 2047. For accounting purposes, the asset retirement cost is amortized using a unit-of-production method based on proved reserves before royalties while the asset retirement obligation accretes until the time the obligation is settled.

Taxes

Future Income Taxes

Future income taxes arise from differences between the accounting and tax bases of assets and liabilities. A portion of the future income tax liability that is recorded on the balance sheet will be recovered through earnings before 2011.

Our future income tax expense was $1.4 million for the quarter ended September 30, 2008 compared to a recovery of $8.8 million for the same period in 2007. The increased expense is the result of commodity derivative instrument gains during the third quarter of 2008 which were partially offset by a future tax recovery related to the Joslyn disposition that closed July 31, 2008.

In July 2008, the Department of Finance issued draft amendments to the Income Tax Regulations regarding the provincial tax rate for new specified investment flow through ("SIFT") entities. These amendments are generally designed to tax SIFT entities at the same level as a corporation and are expected to be enacted later in 2008 and be effective January 1, 2011. The amendments were not considered substantively enacted at September 30, 2008. As a result there was no consequential impact on future income taxes in the third quarter however this will result in a future income tax recovery when enacted.

The Department of Finance has released draft legislative proposals which include amendments to allow a SIFT to convert into a corporation without adverse Canadian tax consequences for the trust or its Canadian unitholders. We believe that a trust conversion under the proposed rules would qualify as a U.S. tax deferred transaction for our U.S. unitholders as well. Enerplus submitted comments on these proposals as permitted by the Canadian Department of Finance. We continue to review the legislative proposals to determine the impact to Enerplus should we convert into a corporation.

Current Income Taxes

In our current structure payments are made between the operating entities and the Fund, which ultimately transfers both the income and future tax liability to our unitholders. As a result no cash income taxes have been paid by our Canadian operating entities. However, an income tax liability of $24.3 million was triggered on the acquisition of Focus. This liability was included in Focus' assumed working capital and was paid in April 2008. We expect to recover the majority of this amount during 2008 as a result of claiming taxable deductions. For the nine months ended September 30, 2008 we have recorded $16.9 million in recoveries related to the $24.3 million.

The amount of current taxes recorded with respect to our U.S. operations is dependent upon income levels along with the timing of capital expenditures and the repatriation of funds to Canada. For the three and nine months ended September 30, 2008 our U.S. operations incurred taxes (income and withholding) in the amount of $14.2 million and $47.9 million respectively, compared to $5.1 and $10.4 million during the same periods in 2007. The increase in current taxes was due to an increase in net income combined with a decrease in capital expenditures in 2008.

We expect our U.S. current income and withholding taxes to average approximately 25% of cash flow from U.S. operations based on current commodity prices, our current development capital program and assuming excess funds are repatriated to Canada.

Net Income

Net income for the third quarter of 2008 was $465.8 million or $2.82 per trust unit compared to $93.0 million or $0.72 per trust unit in the same period for 2007. The third quarter 2008 increase compared to the same period in 2007 is primarily due to an increase in oil and gas sales of $284.4 million and an increase in cash and non-cash commodity derivative instrument gains of $217.1 million, which were offset by increased royalties of $52.5 million and a $45.2 million increase in DDA&A.

Net income for the nine months ended September 30, 2008 was $699.4 million or $4.40 per trust unit compared to $241.0 million or $1.90 per trust unit for the same period in 2007. The $458.4 million increase in net income for the nine months ended September 30, 2008 was primarily due to an increase in oil and gas sales of $762.2 million and a $122.7 million increase in the future tax recovery, which were partially offset by increases in royalties of $140.6 million, cash and non-cash commodity derivative instrument losses of $90.7 million and DDA&A of $121.5 million.

Cash Flow from Operating Activities

Cash flow for the three and nine months ended September 30, 2008 was $383.6 million ($2.33 per trust unit) and $1,004.2 million ($6.32 per trust unit) respectively, compared to $232.8 million ($1.80 per trust unit) and $663.5 million ($5.22 per trust unit) for the three and nine months ended September 30, 2007. The increases per trust unit were primarily a result of higher commodity prices combined with increased oil and gas sales resulting from the Focus acquisition.

Selected Financial Results

	Three months ended September 30, 2008			Three months ended September 30, 2007		
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			95,644			79,891
Weighted average sales price[2]	$ 73.62	$ –	$ 73.62	$49.64	$ –	$ 49.64
Royalties	(13.71)	–	(13.71)	(9.28)	–	(9.28)
Commodity derivative instruments	(6.82)	31.90	25.08	1.00	(0.51)	0.49
Operating costs	(10.10)	(0.11)	(10.21)	(9.61)	(0.12)	(9.73)
General and administrative	(1.50)	(0.20)	(1.70)	(2.11)	(0.30)	(2.41)
Interest expense, net of other income	(0.97)	0.18	(0.79)	(1.40)	0.54	(0.86)
Foreign exchange gain/(loss)	(0.49)	0.19	(0.30)	0.06	0.03	0.09
Current income tax	(0.59)	–	(0.59)	(0.70)	–	(0.70)
Restoration and abandonment cash costs	(0.54)	0.54	–	(0.48)	0.48	–
Depletion, depreciation, amortization and accretion	–	(18.32)	(18.32)	–	(15.78)	(15.78)
Future income tax recovery/(expense)	–	(0.15)	(0.15)	–	1.20	1.20
Total per BOE	$ 38.90	$ 14.03	$ 52.93	$27.12	$(14.46)	$ 12.66

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

Per BOE of production (6:1)	Nine months ended September 30, 2008 Operating Cash Flow[1]	Non-Cash & Other Items	Total	Nine months ended September 30, 2007 Operating Cash Flow[1]	Non-Cash & Other Items	Total
Production per day			95,010			82,777
Weighted average sales price[2]	$ 72.44	$ –	$ 72.44	$49.89	$ –	$ 49.89
Royalties	(13.54)	–	(13.54)	(9.38)	–	(9.38)
Commodity derivative instruments	(5.19)	1.55	(3.64)	0.63	(0.81)	(0.18)
Operating costs	(9.51)	(0.01)	(9.52)	(9.32)	0.01	(9.31)
General and administrative	(1.66)	(0.21)	(1.87)	(2.00)	(0.28)	(2.28)
Interest expense, net of other income	(1.06)	0.06	(1.00)	(1.29)	0.15	(1.14)
Foreign exchange (loss)/gain	(0.17)	(0.02)	(0.19)	(0.05)	0.23	0.18
Current income tax	(1.19)	–	(1.19)	(0.46)	–	(0.46)
Restoration and abandonment cash costs	(0.52)	0.52	–	(0.47)	0.47	–
Depletion, depreciation, amortization and accretion	–	(18.19)	(18.19)	–	(15.58)	(15.58)
Future income tax recovery/(expense)	–	3.24	3.24	–	(1.70)	(1.70)
Gain on sale of marketable securities[3]	–	0.32	0.32	–	0.62	0.62
Total per BOE	$ 39.60	$(12.74)	$ 26.86	$27.55	$(16.89)	$ 10.66

(1) Cash Flow from Operating Activities before changes in non-cash working capital.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(3) Gain on sale of marketable securities was a cash item however it is included in cash flow from investing activities not cash flow from operating activities.

Selected Canadian and U.S. Results

The following tables provide a geographical analysis of key operating and financial results for the three and nine months ended September 30, 2008 and 2007.

(CDN$ millions, except per unit amounts)	Three months ended September 30, 2008 Canada	U.S.	Total	Three months ended September 30, 2007 Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	329,047	12,756	341,803	241,196	10,068	251,264
Crude oil (bbls/day)	25,484	8,635	34,119	24,236	9,841	34,077
Natural gas liquids (bbls/day)	4,557	–	4,557	3,937	–	3,937
Total Daily Sales (BOE/day)	84,883	10,761	95,644	68,372	11,519	79,891
Pricing[1]						
Natural gas (per Mcf)	$ 8.17	$ 10.39	$ 8.25	$ 5.58	$ 5.67	$ 5.59
Crude oil (per bbl)	110.10	112.02	110.63	65.78	77.49	69.16
Natural gas liquids (per bbl)	81.20	–	81.20	50.79	–	50.79
Capital Expenditures						
Development capital and office	$ 146.7	$ 18.9	$ 165.6	$ 70.5	$ 21.8	$ 92.3
Acquisitions of oil and gas properties	4.5	0.1	4.6	1.8	–	1.8
Dispositions of oil and gas properties	(502.6)	0.1	(502.5)	(0.1)	–	(0.1)

(CDN$ millions, except per unit amounts)	Three months ended September 30, 2008 Canada	U.S.	Total	Three months ended September 30, 2007 Canada	U.S.	Total
Revenues						
Oil and gas sales[(1)]	$ 546.5	$ 101.3	$ 647.8	$ 289.4	$ 75.4	$ 364.8
Royalties[(2)]	(98.8)	(21.8)	(120.6)	(52.6)	(15.6)	(68.2)
Financial contracts	220.7	–	220.7	3.6	–	3.6
Expenses						
Operating	$ 85.1	$ 4.7	$ 89.8	$ 68.9	$ 2.7	$ 71.6
General and administrative	13.6	1.3	14.9	16.3	1.4	17.7
Depletion, depreciation, amortization and accretion	139.2	22.0	161.2	88.9	27.1	116.0
Current income taxes (recovery)/expense	(9.0)	14.2	5.2	–	5.1	5.1

(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)	Nine months ended September 30, 2008 Canada	U.S.	Total	Nine months ended September 30, 2007 Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	323,819	12,509	336,328	253,698	10,186	263,884
Crude oil (bbls/day)	24,955	9,340	34,295	24,705	9,897	34,602
Natural gas liquids (bbls/day)	4,660	–	4,660	4,194	–	4,194
Total Daily Sales (BOE/day)	83,585	11,425	95,010	71,182	11,595	82,777
Pricing[(1)]						
Natural gas (per Mcf)	$ 8.53	$ 10.41	$ 8.60	$ 6.63	$ 6.78	$ 6.63
Crude oil (per bbl)	103.73	106.83	103.85	60.06	69.45	62.75
Natural gas liquids (per bbl)	77.21	–	77.21	49.26	–	49.26
Capital Expenditures						
Development capital and office	$ 331.5	$ 52.0	$ 383.5	$ 193.1	$ 92.5	$ 285.6
Acquisitions of oil and gas properties	13.9	–	13.9	208.3	60.8	269.1
Dispositions of oil and gas properties	(504.8)	0.1	(504.7)	(5.6)	–	(5.6)
Revenues						
Oil and gas sales[(1)]	$ 1,576.8	$ 309.1	$ 1,885.9	$ 920.8	$ 206.5	$ 1,127.3
Royalties[(2)]	(286.2)	(66.3)	(352.5)	(170.2)	(41.7)	(211.9)
Financial contracts	(94.7)	–	(94.7)	(4.1)	–	(4.1)
Expenses						
Operating	$ 234.5	$ 13.3	$ 247.8	$ 203.3	$ 7.0	$ 210.3
General and administrative	44.7	4.0	48.7	46.1	5.4	51.5
Depletion, depreciation, amortization and accretion	407.2	66.3	473.5	269.9	82.1	352.0
Current income taxes (recovery)/expense	(16.9)	47.9	31.0	–	10.4	10.4

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

Quarterly Financial Information

Oil and gas sales were relatively flat for the first three quarters of 2006 but began to decrease in the fourth quarter 2006 through 2007 primarily due to softening natural gas prices. During the first half of 2008 production and commodity prices were increasing resulting in additional oil and gas sales. During the third quarter of 2008 our realized natural gas and crude oil prices reduced 16% and 3% to $8.25/Mcf and $110.63/bbl compared to the second quarter of 2008 respectively, resulting in lower oil and gas sales.

Net income has been affected by additional production from the Focus acquisition, fluctuating commodity prices (both current and future), risk management costs, the strengthening Canadian dollar, higher operating costs, changes in future tax provisions as well as changes to accounting policies adopted during 2007.

Quarterly Financial Information ($ millions, except per trust unit amounts)	Oil and Gas Sales[1]	Net Income	Net Income per trust unit Basic	Net Income per trust unit Diluted
2008				
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	$1,885.9	$699.4	$4.40	$4.40
2007				
Fourth Quarter	$ 389.8	$ 98.7	$0.76	$0.76
Third Quarter	364.8	93.0	0.72	0.72
Second Quarter	382.5	40.1	0.31	0.31
First quarter	380.0	107.9	0.88	0.87
Total	$1,517.1	$339.7	$2.66	$2.66
2006				
Fourth Quarter	$ 369.5	$110.2	$0.90	$0.89
Third Quarter	398.0	161.3	1.31	1.31
Second Quarter	403.5	146.0	1.19	1.19
First Quarter	401.7	127.3	1.08	1.07
Total	$1,572.7	$544.8	$4.48	$4.47

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

Liquidity and Capital Resources

Capital Markets and Enerplus' Credit Exposure

The recent turmoil in the financial markets has negatively impacted the availability of credit and equity in the marketplace. The current market conditions indicate that it may be difficult to issue additional equity or increase credit capacity without significant costs at this time. In addition, there has been a dramatic reduction in crude oil and natural gas prices since September 30, 2008. As a result there has been a greater emphasis on evaluating credit capacity, credit counterparties and liquidity. We have discussed these risks as they relate to our credit facility, oil and gas sales counterparties, financial derivative counterparties and joint venture partners below.

Credit Facility

Enerplus' bank credit facility is an unsecured, covenant-based credit agreement with a syndicate of thirteen financial institutions, a summary of which was filed on March 18, 2008 as a "Material document" on the Fund's SEDAR profile at www.sedar.com. Of the thirteen syndicate members in Enerplus' facility, seven are major Canadian banks which represent approximately $1.025 billion or 73% of the commitments under the $1.4 billion facility. The facility is extendable each year and is currently set to expire in November 2010. Rates under the facility range between 55.0 and 110.0 basis points over bankers' acceptance rates and are significantly lower than rates currently being negotiated in the marketplace. At September 30, 2008 we have drawn $277.3 million or approximately 20% of our $1.4 billion facility and have a trailing debt-to-cash flow ratio of 0.4x. Our borrowing cost is currently 55.0 basis points over bankers' acceptance rates.

As at September 30, 2008 Enerplus is in compliance with all covenants under the credit facility. Our exposure to our lenders relates to their potential inability to fund. Should a lender be unable or choose not to fund, other lenders have the right, but not the obligation, to increase their commitment levels to cover the shortfall. Failure to fund would be considered a breach of contract and could result in potential damages in favor of Enerplus, however the likelihood of substantiating and receiving damages is unknown. We have not experienced any funding issues under the facility to date and we anticipate that the proposed government measures to guarantee inter-bank lending will improve market liquidity and reduce this potential risk for Enerplus.

Oil and Gas Sales Counterparties

The Fund's oil and gas receivables are with customers in the petroleum and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. We also have a credit review process that we use to assess and monitor our counterparties' credit worthiness on a regular basis. This process involves reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted we obtain financial assurances such as letters of credit, parental guarantees, or third party insurance to mitigate our credit risk. This process is completed for both our oil and gas sales counterparties as well as our financial derivative counterparties. For the nine months ended September 30, 2008, we have made a $1.5 million bad debt provision, the majority of which relates to our exposure to a Canadian subsidiary of SemGroup L.P., which is currently subject to insolvency proceeding in the U.S.

Financial Derivative Counterparties

The Fund is exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. The Fund mitigates this risk by entering into transactions with highly rated major financial institutions, the majority of which are members of our bank syndicate. We have no exposure to Lehman Brothers, which is currently in insolvency proceedings. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the majority of our financial counterparties. These agreements provide some credit protection in that they allow parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. Absent an ISDA we rely on long form confirmations which provide Enerplus with similar credit protection in terms of aggregating transactions and netting for settlement in the case of a credit event.

We will continue to monitor developments in the financial markets that could impact the credit worthiness of our financial counterparties however it has recently been very difficult to foresee counterparty solvency issues. To date we have not experienced any losses due to non-performance by our derivative counterparties.

Joint Venture Partners

We continue to attempt to mitigate the credit risk associated with our joint interest receivables by reviewing and actively following up on older accounts. In addition, we are specifically monitoring our receivables against a watch list of publicly traded companies that have high debt-to-cash flow ratios or highly drawn bank facilities. We do not anticipate any significant issues in the collection of our joint interest receivables at this time outside of those for which we have already provided. However, if the current low commodity prices and tight capital markets prevail, there is a risk of increased bad debts related to our industry partners.

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 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.

Enerplus currently has approximately $10 billion of safe harbour growth capacity within the context of the Government's "normal growth" guidelines for SIFT's. This amount is calculated in reference to the combined market capitalizations of Enerplus and Focus on October 31, 2006 and also includes equity that may be issued to replace existing debt of both entities at that time.

Distribution Policy

The amount of cash distributions is proposed by management and approved by the Board of Directors. We continually assess distribution levels with respect to anticipated cash flows, debt levels and capital spending plans. The level of cash withheld has historically varied between approximately 10% and 40% of annual cash flow from operating activities and is dependent upon numerous factors, the most significant of which are 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.

Although we intend to continue to make cash distributions to our unitholders, these distributions are not guaranteed. To the extent there is taxable income at the trust level, determined in accordance with the Canadian Income Tax Act, the distribution of that taxable income is non-discretionary.

The significant decrease in crude oil and natural gas prices has resulted in a decrease in our overall cash flows. This commodity downturn, combined with the current uncertainty in the capital markets, has reinforced our belief in the importance of maintaining strong financial flexibility. To that end, we have reduced our monthly cash distribution to $0.38 per unit from $0.47 per unit effective November 20, 2008.

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 third quarter of 2008 cash distributions of $224.4 million were funded entirely through cash flow of $383.6 million. For the nine months ended September 30, 2008 our cash distributions of $619.1 million were funded entirely through cash flow of $1,004.2 million.

Our payout ratio, which is calculated as cash distributions divided by cash flow, was 59% and 62% for the three and nine months ended September 30, 2008 respectively, compared to 70% and 73% for the same periods in 2007. See "Non-GAAP Measures" in this MD&A.

In aggregate, our 2008 third quarter cash distributions of $224.4 million combined with our development capital and office expenditures of $165.6 million totaled $390.0 million, or approximately 102% of our cash flow of $383.6 million. For the nine months ended September 30, 2008 our cash distributions of $619.1 million combined with our development capital and office expenditures of $383.5 million totaled $1,002.6 million, or approximately 100% of our cash flow of $1,004.2 million. We expect to support our distributions and capital expenditures with our cash flow, however we will continue to fund acquisitions and growth through additional debt and equity when required. There will also be years when we are investing capital in opportunities that do not immediately generate cash flow (such as our Kirby oil sands project) where we may also use debt and equity to support the investment.

For the three months ended September 30, 2008, our net income exceeded our cash distributions by $241.4 million whereas in 2007 our cash distributions exceeded our net income by $70.1 million. For the nine months ended September 30, 2008 our net income exceeded our cash distributions by $80.3 million whereas in 2007 our cash distributions exceeded our net income by $242.4 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 impact cash flow from operations. 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, 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 costs of our PP&E and not the fair market value of replacing those assets within the context of the current environment.

It is not possible 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. Therefore 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 September 30, 2008**	**Nine months ended September 30, 2008**	Year ended December 31, 2007	Year ended December 31, 2006
Cash flow from operating activities	**$383.6**	**$1,004.2**	$ 868.5	$863.7
Cash distributions	**224.4**	**619.1**	646.8	614.3
Excess of cash flow over cash distributions	**$159.2**	**$ 385.1**	$ 221.7	$249.4
Net income	**$465.8**	**$ 699.4**	$ 339.7	$544.8
Excess/(shortfall) of net income over cash distributions	**241.4**	**80.3**	(307.1)	(69.5)
Cash distributions per weighted average trust unit	**$ 1.36**	**$ 3.89**	$ 5.07	$ 5.05
Payout ratio[1]	**59%**	**62%**	74%	71%

[1] Based on cash distributions divided by cash flow from operating activities. See "Non-GAAP Measures" in this MD&A.

Long-Term Debt

Long-term debt at September 30, 2008 was $522.8 million which is comprised of $277.3 million of bank indebtedness and $245.5 million of senior unsecured notes. Long-term debt decreased by $203.9 million from December 31, 2007 due to the $502.0 million of net proceeds received from the Joslyn disposition partially offset by additional debt acquired in the Focus acquisition.

Our working capital deficiency, excluding cash, at September 30, 2008 decreased to $161.7 million from $203.4 million at December 31, 2007. Excluding current deferred financial assets and credits and the related current future income taxes, our working capital deficiency decreased by $16.4 million compared to December 31, 2007. This decrease is primarily due to higher production levels and commodity prices which more than offset the additional payables associated with more units and higher distributions.

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

Financial Leverage and Coverage	September 30, 2008	December 31, 2007
Long-term debt to trailing cash flow	0.4x	0.8x
Cash flow to interest expense	25.3x	25.8x
Long-term debt to long-term debt plus equity	11%	22%

Long-term debt is measured net of cash.
Cash flow and interest expense are 12-months trailing.

At September 30, 2008 Enerplus had a $1.4 billion unsecured covenant based term bank facility maturing November 2010, through its wholly-owned subsidiary EnerMark Inc. We have the ability to extend the facility each year or repay the entire balance at the end of the term. Due to the volatility in the credit capital markets we chose not to extend the term of the credit facility this year. The facility carries floating interest rates that we expect to range between 55.0 and 110.0 basis points over bankers' acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items.

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 September 30, 2008 we were in compliance with our debt covenants, the most restrictive of which limits our long-term debt to three times trailing cash flow including acquisition cash flows. Refer to "Debt of Enerplus" in our Annual Information Form for the year ended December 31, 2007 for a detailed description of these covenants.

Principal payments on Enerplus' senior unsecured notes are required commencing in 2010 and 2011 and are more fully discussed in Note 5.

Net proceeds of $502.0 million from the Joslyn disposition which closed July 31, 2008 have been used to pay down debt, improving our debt-to-cash flow ratio which supports our ability to fund future development capital and acquisition activities and minimizes the need to issue additional equity. We continue to have adequate liquidity to fund planned development capital spending for the remainder of 2008 through a combination of cash flow retained by the business and debt, if needed.

Commitments

During the quarter we acquired additional office space which results in the following total commitments for our office leases:

		Minimum Annual Commitment Each Year					Total Committed
($ thousands)	Total	2009	2010	2011	2012	2013	after 2013
Office leases	$69,493	$8,722	$12,266	$12,316	$12,400	$12,400	$11,389

Trust Unit Information

We had 165,197,000 trust units outstanding at September 30, 2008. This includes the 30,150,000 units issued on February 13, 2008 to acquire Focus and 7,586,000 exchangeable limited partnership units of Enerplus Exchangeable Limited Partnership outstanding from the original 9,087,000 exchangeable limited partnership units which were assumed with the Focus acquisition. The 7,586,000 exchangeable limited partnership units are convertible at the option of the holder into 0.425 of an Enerplus trust unit (3,224,000 trust units). This compares to 129,552,000 trust units at September 30, 2007 and 129,813,000 trust units outstanding at December 31, 2007. Including the exchangeable limited partnership units the weighted average basic number of trust units outstanding for the nine months ended September 30, 2008 was 158,980,000 (2007 – 127,025,000). At October 31, 2008 we had 165,286,000 trust units outstanding including the equivalent limited partnership units.

During the three months ended September 30, 2008, 488,000 trust units (2007 – 347,000) 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 $19.3 million (2007 – $15.1 million) of additional equity to the Fund. For the nine months ended September 30, 2008 $60.0 million of additional equity (2007 – $46.8 million) and 1,488,000 trust units (2007–1,046,000) were issued pursuant to the DRIP and the trust unit incentive rights plans. For further details see Note 8.

Canadian and U.S. Taxpayers

Enerplus currently estimates that approximately 95% of cash distributions paid to Canadian and U.S unitholders will be taxable and the remaining 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.

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. This preferential rate of tax for "Qualified Dividends" is set to expire at the end of 2010. The terms for continuing this Qualified Dividend tax rate are largely dependent on the outcome of the U.S. presidential election. Draft U.S. Tax Bill 1672, which proposes to make dividends from Canadian income trusts such as Enerplus ineligible for treatment as a "Qualified Dividend", has not progressed in the U.S. approval process. Therefore, we are unable to determine when or if Bill 1672 will be enacted as presented.

In October 2008, Enerplus estimated its non-resident ownership to be approximately 66%.

Greenhouse Gas and Carbon Emissions

Enerplus continues to monitor and evaluate the developments associated with carbon emissions regulations associated with environmental policy and legislation in all jurisdictions where we operate. At this stage, without further clarity and specific details from the Government of Canada, it is impossible to forecast with any certainty the increased costs associated with the proposed greenhouse gas and carbon capture regulations.

Recent Canadian Accounting and Related Pronouncements

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada's Accounting Standards Board (AcSB) ratified a strategic plan that will result in Canadian GAAP, as used by public entities, being converged with International Financial Reporting Standards (IFRS) by 2011. On February 13, 2008 the AcSB confirmed that use of IFRS will be required for public companies beginning January 1, 2011. Currently, we are assessing the effects of adoption and developing a plan accordingly. We will continue to monitor any changes in the adoption of IFRS and will update plans as necessary.

Internal Controls and Procedures

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Additional Information

Additional information relating to Enerplus Resources Fund, 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 management's discussion and analysis ("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" 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: the amount, timing and tax treatment of cash distributions to unitholders; payout ratios; tax treatment of income trusts such as the Fund; the structure of the Fund and its subsidiaries; the Fund's income taxes, tax liabilities and tax pools; the volume and product mix of the Fund's oil and gas production; oil and natural gas prices and the Fund's risk management programs; the amount of asset retirement obligations; future liquidity and financial capacity and resources; cost and expense estimates; results from operations and financial ratios; cash flow sensitivities; royalty rates and their impact on the Fund's operations and results; future growth including development, exploration, and acquisition and development activities and related expenditures, including with respect to both our conventional and oil sands activities.

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 continue to conduct its operations in a manner consistent with past operations; the general continuance of current or, where applicable, assumed industry conditions; availability of debt and/or equity sources to fund the Fund's capital and operating requirements as needed; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; the accuracy of the estimates of the Fund's reserve volumes; and certain commodity price and other cost assumptions. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable at this time 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; unanticipated operating results or production declines; changes in tax or environmental laws or royalty rates; increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserves volumes; limited, unfavourable or no access to debt or equity capital markets; increased costs and expenses; 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 identified in this MD&A, our MD&A for the year ended December 31, 2007 and in the Fund's Annual Information Form for the year ended December 31, 2007, copies of which are available on the Fund's SEDAR profile at www.sedar.com and which also form part of the Fund's Form 40-F for the year ended December 31, 2007 filed with the SEC, a copy of which is 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.

This report contains estimates of "contingent resources". "Contingent resources" are not, and should not be confused with, oil and gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook as "those quantities of petroleum estimated, as of given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage." There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that Enerplus will produce any portion of the volumes currently classified as contingent resources. The primary contingencies which currently prevent the classification of Enerplus' disclosed contingent resources associated with the Kirby oil sands project as reserves consist of current uncertainties around the specific scope and timing of the project development, proposed reliance on technologies that have not yet been demonstrated to be commercially applicable in oil sands applications, the uncertainty regarding marketing plans for production from the subject areas and improved estimation of project costs. Based on current information and market conditions, Enerplus believes that development of the Kirby project will proceed as described in this report. However, there are a number of inherent risks and contingencies associated with the development of the project, including commodity price fluctuations, project costs, receipt of regulatory approvals and those other risks and contingencies described above and under "Risk Factors" in the Fund's Annual Information Form dated March 13, 2008, a copy of which is available on Enerplus' SEDAR profile at www.sedar.com, and which also forms part of Enerplus' Form 40-F for the year ended December 31, 2007 filed with the SEC, a copy of which is available at www.sec.gov.

CONSOLIDATED BALANCE SHEETS

(CDN$ thousands) (Unaudited)	September 30, 2008	December 31, 2007
Assets		
Current assets		
Cash	$ 560	$ 1,702
Accounts receivable	182,821	145,602
Deferred financial assets (Note 9)	14,164	10,157
Future income taxes	2,129	10,807
Other current	6,560	6,373
	206,234	174,641
Property, plant and equipment (Note 2)	5,105,710	3,872,818
Goodwill (Note 4)	609,423	195,112
Deferred financial assets (Note 9)	2,040	–
Other assets (Note 9)	57,116	60,559
	$ 5,980,523	$ 4,303,130
Liabilities		
Current liabilities		
Accounts payable	$ 267,304	$ 269,375
Distributions payable to unitholders	77,643	54,522
Deferred financial credits (Note 9)	22,398	52,488
	367,345	376,385
Long-term debt (Note 5)	522,814	726,677
Deferred financial credits (Note 9)	74,986	90,090
Future income taxes	621,133	304,259
Asset retirement obligations (Note 3)	203,837	165,719
	1,422,770	1,286,745
Equity		
Unitholders' capital (Note 8)	5,459,138	4,032,680
Accumulated deficit	(1,203,677)	(1,283,953)
Accumulated other comprehensive income	(65,053)	(108,727)
	(1,268,730)	(1,392,680)
	4,190,408	2,640,000
	$ 5,980,523	$ 4,303,130

CONSOLIDATED STATEMENTS OF ACCUMULATED DEFICIT

(CDN$ thousands) (Unaudited)	Three months ended September 30, 2008	2007	Nine months ended September 30, 2008	2007
Accumulated income, beginning of period	**$ 2,520,551**	$ 2,095,193	**$ 2,286,927**	$ 1,952,960
Adjustment for adoption of financial instruments standards	**–**	–	**–**	(5,724)
Revised accumulated income, beginning of period	**2,520,551**	2,095,193	**2,286,927**	1,947,236
Net income	**465,773**	93,033	**699,397**	240,990
Accumulated income, end of period	**2,986,324**	2,188,226	**2,986,324**	2,188,226
Accumulated cash distributions, beginning of period	**(3,965,584)**	(3,244,323)	**(3,570,880)**	(2,924,045)
Cash distributions	**(224,417)**	(163,110)	**(619,121)**	(483,388)
Accumulated cash distributions, end of period	**(4,190,001)**	(3,407,433)	**(4,190,001)**	(3,407,433)
Accumulated deficit, end of period	**$(1,203,677)**	$(1,219,207)	**$(1,203,677)**	$(1,219,207)

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

(CDN$ thousands) (Unaudited)	Three months ended September 30, 2008	2007	Nine months ended September 30, 2008	2007
Balance, beginning of period	**$ (93,128)**	$ (65,378)	**$(108,727)**	$ (8,979)
Transition adjustments on adoption:				
Cash flow hedges	**–**	–	**–**	660
Available for sale marketable securities	**–**	–	**–**	14,252
Other comprehensive income/(loss)	**28,075**	(39,343)	**43,674**	(110,654)
Balance, end of period	**$ (65,053)**	$(104,721)	**$ (65,053)**	$(104,721)

CONSOLIDATED STATEMENTS OF INCOME

(CDN$ thousands, except per trust unit amounts) (Unaudited)	Three months ended September 30, 2008	2007	Nine months ended September 30, 2008	2007
Revenues				
Oil and gas sales	$ 654,592	$370,163	$1,906,131	$1,143,960
Royalties	(120,635)	(68,165)	(352,511)	(211,927)
Commodity derivative instruments (Note 9)	220,652	3,585	(94,742)	(4,067)
Other income	295	143	15,822	14,575
	754,904	305,726	1,474,700	942,541
Expenses				
Operating	89,801	71,551	247,791	210,337
General and administrative	14,935	17,718	48,699	51,488
Transportation	6,757	5,334	20,201	16,651
Interest (Note 6)	7,238	6,438	33,539	26,400
Foreign exchange (Note 7)	2,655	(643)	4,931	(4,117)
Depletion, depreciation, amortization and accretion	161,178	116,001	473,468	352,001
	282,564	216,399	828,629	652,760
Income before taxes	472,340	89,327	646,071	289,781
Current taxes	5,211	5,081	30,963	10,372
Future income tax expense/(recovery)	1,356	(8,787)	(84,289)	38,419
Net Income	$ 465,773	$ 93,033	$ 699,397	$ 240,990
Net income per trust unit				
Basic	$ 2.82	$ 0.72	$ 4.40	$ 1.90
Diluted	$ 2.82	$ 0.72	$ 4.40	$ 1.90
Weighted average number of trust units outstanding (thousands)[1]				
Basic	164,908	129,373	158,980	127,025
Diluted	165,001	129,402	159,089	127,083

(1) Includes exchangeable limited partnership units.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(CDN$ thousands) (Unaudited)	Three months ended September 30, 2008	2007	Nine months ended September 30, 2008	2007
Net income	$465,773	$ 93,033	$699,397	$240,990
Other comprehensive income/(loss), net of tax:				
Unrealized gain/(loss) on marketable securities	–	545	2,578	(109)
Realized gains on marketable securities included in net income	–	–	(6,158)	(11,654)
Gains and losses on derivatives designated as hedges in prior periods included in net income	–	(177)	74	(557)
Change in cumulative translation adjustment	28,075	(39,711)	47,180	(98,334)
Other comprehensive income/(loss)	28,075	(39,343)	43,674	(110,654)
Comprehensive income	$493,848	$ 53,690	$743,071	$130,336

CONSOLIDATED STATEMENTS OF CASH FLOWS

(CDN$ thousands) (Unaudited)	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Operating Activities				
Net income	$ 465,773	$ 93,033	$ 699,397	$ 240,990
Non-cash items add/(deduct):				
Depletion, depreciation, amortization and accretion	161,178	116,001	473,468	352,001
Change in fair value of derivative instruments (Note 9)	(292,419)	16,388	(57,160)	49,841
Unit based compensation (Note 8)	1,783	2,192	5,363	6,410
Foreign exchange on translation of senior notes (Note 7)	9,570	(15,586)	16,645	(39,276)
Future income tax	1,356	(8,787)	(84,289)	38,419
Amortization of senior notes premium	(164)	(155)	(474)	(483)
Reclassification adjustments from AOCI to net income	–	(177)	92	(557)
Gain on sale of marketable securities	–	–	(8,263)	(14,055)
Asset retirement obligations settled (Note 3)	(4,734)	(3,547)	(13,501)	(10,664)
	342,343	199,362	1,031,278	622,626
Decrease/(Increase) in non-cash operating working capital	41,230	33,439	(27,032)	40,838
Cash flow from operating activities	383,573	232,801	1,004,246	663,464
Financing Activities				
Issue of trust units, net of issue costs (Note 8)	19,255	15,087	59,951	246,311
Cash distributions to unitholders	(224,417)	(163,110)	(619,121)	(483,388)
(Decrease)/Increase in bank credit facilities	(514,893)	8,145	(550,947)	72,495
Decrease in non-cash financing working capital	8,463	141	23,121	2,690
Cash flow from financing activities	(711,592)	(139,737)	(1,086,996)	(161,892)
Investing Activities				
Capital expenditures	(165,647)	(92,324)	(383,531)	(285,678)
Property acquisitions	(4,574)	(1,755)	(13,863)	(214,399)
Property dispositions (Note 2)	502,489	96	504,697	(1,056)
Proceeds on sale of marketable securities	–	–	18,320	16,467
Purchase of equity investments	(7,150)	–	(7,150)	–
Decrease/(increase) in non-cash financing working capital	3,378	3,419	(37,258)	(11,078)
Cash flow from investing activities	328,496	(90,564)	81,215	(495,744)
Effect of exchange rate changes on cash	(640)	(1,980)	393	(3,382)
Change in cash	(163)	520	(1,142)	2,446
Cash, beginning of period	723	2,050	1,702	124
Cash, end of period	$ 560	$ 2,570	$ 560	$ 2,570
Supplementary Cash Flow Information				
Cash income taxes paid	$ 28,320	$ 3,340	$ 62,078	$ 10,586
Cash interest paid	$ 5,017	$ 6,052	$ 31,315	$ 26,782

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, 2007. 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, 2007. With the exception of additional disclosures included in Note 9 regarding financial instruments and capital management, the disclosures provided below are incremental to those included in the 2007 annual consolidated financial statements of the Fund.

2. PROPERTY, PLANT AND EQUIPMENT (PP&E)

($ thousands)	September 30, 2008	December 31, 2007
Property, plant and equipment	$ 8,145,193	$ 6,429,241
Accumulated depletion, depreciation and accretion	(3,039,483)	(2,556,423)
Net property, plant and equipment	$ 5,105,710	$ 3,872,818

Capitalized development general and administrative ("G&A") expense of $16,870,000 (2007 – $12,497,000) is included in PP&E for the nine months ended September 30, 2008. Excluded from PP&E for the depletion and depreciation calculation is $245,988,000 related to the oil sands projects which have not yet commenced commercial production. In 2007 $303,678,000 was excluded from PP&E for the depletion and depreciation calculation related to the Kirby oil sands project as well as the oil sands Joslyn project. The Joslyn project was sold on July 31, 2008 for net proceeds of approximately $502.0 million.

3. ASSET RETIREMENT OBLIGATIONS

Following is a reconciliation of the asset retirement obligations:

($ thousands)	Nine months ended September 30, 2008	Year ended December 31, 2007
Asset retirement obligations, beginning of period	$165,719	$123,619
Corporate acquisition	36,784	–
Changes in estimates	1,589	46,000
Property acquisition and development activity	4,611	6,441
Dispositions	(110)	(756)
Asset retirement obligations settled	(13,501)	(16,280)
Accretion expense	8,745	6,695
Asset retirement obligations, end of period	$203,837	$165,719

4. ACQUISITIONS

Focus Energy Trust

On February 13, 2008 Enerplus closed the acquisition of Focus Energy Trust ("Focus"). Under the plan of arrangement, Focus unitholders received 0.425 of an Enerplus trust unit for each Focus trust unit and Focus Exchangeable Limited Partnership Units became exchangeable into Enerplus trust units at the option of the holder on the basis of 0.425 of an Enerplus trust unit for each Focus Exchangeable Limited Partnership Unit. Total consideration was $1,366,494,000 consisting of 30,149,752 trust units issued, 9,086,666 exchangeable limited partnership units assumed (convertible into 3,861,833 trust units) and transaction costs of $5,350,000. The Fund also assumed bank debt plus an estimated working capital deficit including certain transaction costs paid by Focus of $357,305,000.

The acquisition has been accounted for using the purchase method of accounting and results from the operations of Focus from February 13, 2008 onward have been included in the Fund's consolidated financial statements. The allocation of the consideration paid to the fair value of the assets acquired and liabilities assumed plus future income tax cost are summarized below:

Net Assets Acquired
($ thousands)

Property, plant and equipment	$1,757,520
Other assets	4,566
Goodwill	403,588
Working capital deficit	(26,393)
Deferred financial credits	(5,919)
Long-term debt	(330,912)
Asset retirement obligations	(36,784)
Future income taxes	(399,172)
Total net assets acquired	$1,366,494

Consideration paid
($ thousands)

Trust units issued[(1)]	$1,206,593
Exchangeable limited partnership units assumed[(1)]	154,551
Transaction costs	5,350
Total consideration paid	$1,366,494

(1) Recorded based on a fair value of $40.02 per trust unit

5. LONG-TERM DEBT

($ thousands)	September 30, 2008	December 31, 2007
Bank credit facilities (a)	$ 277,312	$ 497,347
Senior notes (b)		
US$175 million (issued June 19, 2002)	188,267	175,973
US$54 million (issued October 1, 2003)	57,235	53,357
Total long-term debt	$ 522,814	$ 726,677

(a) Unsecured Bank Credit Facility

Enerplus has a $1.4 billion unsecured covenant based term facility that matures November 18, 2010. The facility is extendible each year with a bullet payment required at the end of the term. Various borrowing options are available under the facility including prime rate based advances and bankers' acceptance loans. This facility carries floating interest rates that are expected to range between 55.0 and 110.0 basis points over bankers' acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items. The effective interest rate on the facility for the nine months ended September 30, 2008 was 3.8% (September 30, 2007 – 5.0%).

(b) Senior Unsecured Notes

On June 19, 2002 Enerplus issued US$175,000,000 senior unsecured notes that mature June 19, 2014. The notes have a coupon rate of 6.62% priced at par, with interest paid semi-annually on June 19 and December 19 of each year. Principal payments are required in five equal installments beginning June 19, 2010 and ending June 19, 2014. Concurrent with the issuance of the notes on June 19, 2002, the Fund entered into a cross currency and interest rate swap ("CCIRS") with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal repayments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%.

On October 1, 2003 Enerplus issued US$54,000,000 senior unsecured notes that mature October 1, 2015. The notes have a coupon rate of 5.46% priced at par with interest paid semi-annually on April 1 and October 1 of each year. Principal payments are required in five equal installments beginning October 1, 2011 and ending October 1, 2015. The notes are translated into Canadian dollars using the period end foreign exchange rate. In September 2007 Enerplus entered into foreign exchange swaps that effectively fix the five principal payments on the US$54,000,000 senior unsecured notes at a CDN/US exchange rate of 1.02 or CDN$55,080,000.

On January 1, 2007 in conjunction with the adoption of CICA Sections 3855 and 3865, Enerplus elected to stop designating the CCIRS as a fair value hedge on the US$175,000,000 senior notes. As a result, the Fund recorded the senior notes at their fair value of US$178,681,000. The premium amount of US$3,681,000, representing the difference between the January 1, 2007 fair value and the face amount of the senior notes, will be amortized to net income over the remaining term of the notes using the effective interest method. The effective interest rate over the remaining term of the senior notes is 6.16%. The senior notes are carried at amortized cost and are translated into Canadian dollars using the period end foreign exchange rate. At September 30, 2008 the amortized cost of the US$175,000,000 senior notes was US$177,627,000.

6. INTEREST EXPENSE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2008**	2007	**2008**	2007
Realized				
Interest on long-term debt	**$ 8,813**	$ 10,405	**$ 35,076**	$ 29,842
Unrealized				
Gain on cross currency interest rate swap	**(2,426)**	(4,718)	**(3,551)**	(1,808)
Loss/(gain) on interest rate swaps	**1,015**	871	**2,488**	(1,228)
Amortization of senior notes premium	**(164)**	(120)	**(474)**	(406)
Interest expense	**$ 7,238**	$ 6,438	**$ 33,539**	$ 26,400

7. FOREIGN EXCHANGE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2008**	2007	**2008**	2007
Realized				
Foreign exchange loss/(gain)	**$ 4,349**	$ (415)	**$ 4,367**	$ 1,027
Unrealized				
Foreign exchange loss/(gain) on translation of U.S. dollar denominated senior notes	**9,570**	(15,586)	**16,645**	(39,276)
Foreign exchange (gain)/loss on cross currency interest rate swap	**(9,125)**	14,105	**(13,616)**	32,879
Foreign exchange (gain)/loss on foreign exchange swaps	**(2,139)**	1,253	**(2,465)**	1,253
Foreign exchange loss/(gain)	**$ 2,655**	$ (643)	**$ 4,931**	$ (4,117)

The US$54,000,000 and US$175,000,000 senior unsecured notes are exposed to foreign currency fluctuations and are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Foreign exchange gains and losses are included in the determination of net income for the period.

8. UNITHOLDERS' CAPITAL

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

Unitholders' capital ($ thousands)	**Nine months ended September 30, 2008**	Year ended December 31, 2007
Trust units	**$5,310,972**	$4,020,228
Exchangeable limited partnership units	**129,035**	–
Contributed surplus	**19,131**	12,452
Balance, end of period	**$5,459,138**	$4,032,680

(a) Trust Units

Authorized: Unlimited number of trust units

(thousands)	Nine months ended September 30, 2008 Units	Nine months ended September 30, 2008 Amount	Year ended December 31, 2007 Units	Year ended December 31, 2007 Amount
Issued:				
Balance, beginning of period	129,813	$4,020,228	123,151	$3,706,821
Issued for cash:				
Pursuant to public offerings	–	–	4,250	199,558
Pursuant to rights incentive plan	200	6,595	205	6,758
Cancelled trust units	(116)	(3,794)	–	–
Exchangeable limited partnership units exchanged	638	25,516	–	–
Trust unit rights incentive plan (non-cash) – exercised	–	2,478	–	2,288
DRIP*, net of redemptions	1,288	53,356	1,102	50,053
Issued for acquisition of corporate and property interests (non-cash)	30,150	1,206,593	1,105	54,750
	161,973	$5,310,972	129,813	$4,020,228
Equivalent exchangeable partnership units	3,224	129,035	–	–
Balance, end of period	165,197	$5,440,007	129,813	$4,020,228

* Distribution Reinvestment and Unit Purchase Plan

On February 13, 2008 the Fund issued 30,149,752 trust units pursuant to the Focus acquisition valued at $40.02 per trust unit, being the weighted average trading price of the Fund's units on the Toronto Stock Exchange during the five day trading period surrounding the announcement date of December 3, 2007, for a recorded value of $1,206,593,000.

(b) Exchangeable Limited Partnership Units

In conjunction with the Focus acquisition 9,086,666 Exchangeable Limited Partnership Units issued by Focus Limited Partnership (since renamed Enerplus Exchangeable Limited Partnership) became exchangeable into Enerplus trust units at a ratio of 0.425 of an Enerplus trust unit for each Limited Partnership unit (3,861,833 trust units). The exchangeable limited partnership units are convertible at any time into trust units at the option of the holder and receive cash distributions and have voting rights in accordance with the 0.425 exchange ratio. The Board of Directors may redeem the exchangeable limited partnership units after January 8, 2017, unless certain conditions are met to permit an earlier redemption date. The exchangeable limited partnership units are not listed on any stock exchange and are not transferable. The exchangeable limited partnership units were recorded at fair value, based on Enerplus' five day weighted average trust unit trading price surrounding the December 3, 2007 announcement date of $40.02 multiplied by the 0.425 exchange ratio.

During the third quarter of 2008, 299,000 exchangeable limited partnership units were converted into 127,000 trust units. As at September 30, 2008, the 7,586,000 outstanding exchangeable limited partnership units represent the equivalent of 3,224,000 trust units.

(thousands)	Nine months ended September 30, 2008 Units	Nine months ended September 30, 2008 Amount	Year ended December 31, 2007 Units	Year ended December 31, 2007 Amount
Issued:				
Assumed on February 13, 2008	9,087	$154,551	–	$ –
Exchanged for trust units	(1,501)	(25,516)	–	–
Balance, end of period	7,586	$129,035	–	$ –

(c) Contributed Surplus

Contributed surplus ($ thousands)	Nine months ended September 30, 2008	Year ended December 31, 2007
Balance, beginning of period	$12,452	$ 6,305
Trust unit rights incentive plan (non-cash) – exercised	(2,478)	(2,288)
Trust unit rights incentive plan (non-cash) – expensed	5,363	8,435
Cancelled trust units	3,794	–
Balance, end of period	$19,131	$12,452

(d) Trust Unit Rights Incentive Plan

As at September 30, 2008 a total of 4,236,000 rights were issued and outstanding pursuant to the Trust Unit Rights Incentive Plan ("Rights Incentive Plan") with an average exercise price of $45.32. This represents 2.6% of the total trust units outstanding of which 1,874,000 rights, with an average exercise price of $45.62, were exercisable. Under the Rights Incentive Plan, distributions per trust unit to Enerplus unitholders in a calendar quarter which represent a return of more than 2.5% of the net PP&E of Enerplus at the end of such calendar quarter may result in a reduction in the exercise price of the rights. Results for the first, second and third quarter of 2008 reduced the exercise price of the outstanding rights by $0.43 per trust unit effective July 2008, $0.41 per trust unit effective October 2008 and $0.59 per trust unit effective January 2009.

Activity for the rights issued pursuant to the Rights incentive Plan is as follows:

	Nine months ended September 30, 2008		Year ended December 31, 2007	
	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	3,404	$47.59	3,079	$48.53
Granted	1,384	42.25	816	48.71
Exercised	(200)	32.89	(205)	32.90
Cancelled	(352)	46.84	(286)	50.74
End of period	4,236	$45.32	3,404	$47.59
Rights exercisable at end of period	1,874	$45.62	1,635	$44.84

[1] Exercise price reflects grant prices less reduction in exercise price discussed above.

The Fund uses a binomial lattice option-pricing model to calculate the estimated fair value of rights granted under the plan. Non-cash compensation costs charged to general and administrative expenses related to rights issued for the three and nine months ended September 30, 2008 were $1,783,000 ($0.01 per unit) and $5,363,000 ($0.03 per unit) respectively. Non-cash compensation costs for the three and nine months ended September 30, 2007 were $2,192,000 ($0.02 per unit) and $6,410,000 ($0.05 per unit) respectively.

(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:

	Nine months ended September 30,	
(thousands)	2008	2007
Weighted average trust units	155,977	127,025
Weighted average exchangeable limited partnership units[1]	3,003	–
Basic weighted average units outstanding	158,980	127,025
Dilutive impact of trust unit incentive rights	109	58
Diluted weighted average units outstanding	159,089	127,083

[1] Based on the exchange ratio of 0.425

(f) Performance Trust Unit Plan

The Fund has a Performance Trust Unit ("PTU") plan for executives and employees. Under the plan employees and participants receive cash compensation in relation to the value of a specified number of underlying notional trust units. The number of notional trust units awarded varies by individual and vest at the end of a three year performance period. Upon vesting the plan participant receives a cash payment based on the fair value of the PTU combined with the accrued distributions paid on the notional trust units over the performance period. The fair value of the PTU is dependent upon the underlying trading price of a trust unit multiplied by a performance factor that is determined by comparing the performance of the Fund to its peers over the three year period.

For the three months and nine months ended September 30, 2008 the Fund recorded cash compensation costs of $1,240,000 (2007 – $509,000) and $3,540,000 (2007 – $1,424,000), respectively, under the plan which are included in general and administrative expenses.

At September 30, 2008 there were 419,000 performance trust units outstanding.

9. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

(a) Fair Value of Financial Instruments

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between knowledgeable, willing parties who are under no compulsion to act. Fair values are determined by reference to quoted bid or ask prices, as appropriate, in the most advantageous active market for that instrument to which we have immediate access. Where bid and ask prices are unavailable, we would use the closing price of the most recent transaction for that instrument. In the absence of an active market, we determine fair values based on prevailing market rates for instruments with similar characteristics. Fair values may also be determined based on internal and external valuation models, such as option pricing models and discounted cash flow analysis, that use observable market based inputs and assumptions.

(b) 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.

ii. Accounts Receivable

Accounts receivable are classified as loans and receivables and are reported at amortized cost. At September 30, 2008 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. During the first quarter of 2008 the Fund disposed of certain publicly traded marketable securities which resulted in a gain of $8,263,000 ($6,158,000 net of tax) being reclassified from accumulated other comprehensive income to other income on the Consolidated Statement of Income.

As at September 30, 2008 the Fund did not hold any investments in publicly traded marketable securities. As at December 31, 2007 the Fund reported investments in publicly traded marketable securities at a fair value of $14,676,000.

Marketable securities without a quoted market price in an active market are reported at cost. As at September 30, 2008 the Fund reported investments in marketable securities of private companies at cost of $57,116,000 (December 31, 2007 – $45,400,000) in Other Assets on the Consolidated Balance Sheet.

iv. Accounts Payable & Distributions Payable to Unitholders

Accounts payable and distributions payable to unitholders are classified as other liabilities and are reported at amortized cost. At September 30, 2008 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 September 30, 2008 the carrying value of the bank credit facilities approximated their fair value.

US$175 million senior notes

The US$175,000,000 senior notes, which are classified as other liabilities, are reported at amortized cost of US$177,627,000 and are translated to Canadian dollars at the period end exchange rate. At September 30, 2008 the Canadian dollar amortized cost of the senior notes was approximately $188,267,000 and the fair value of these notes was $184,846,000.

US$54 million senior notes

The US$54,000,000 are classified as other liabilities and reported at their amortized cost of US$54,000,000 and are translated into Canadian dollars at the period end exchange rate. At September 30, 2008 the Canadian dollar amortized cost of the senior notes was approximately $57,235,000 and the fair value of these notes was approximately $52,884,000.

(c) Fair Value of Derivative Financial Instruments

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 September 30, 2008 a current deferred financial asset of $14,164,000, a current deferred financial credit of $22,398,000, a non-current deferred financial asset of $ 2,040,000 and a non-current deferred financial credit of $74,986,000 are recorded on the consolidated balance sheet.

The deferred financial credit relating to crude oil instruments of $22,398,000 at September 30, 2008 consists of the fair value of the financial instruments, representing a loss position of $5,100,000 plus the related deferred premiums of $17,298,000. The deferred financial asset relating to natural gas instruments of $13,986,000 at September 30, 2008 represents a gain position of $20,611,000 less the related deferred premiums of $6,625,000.

The following table summarizes the fair value as at September 30, 2008 and change in fair value for the period ended September 30, 2008 of the Fund's derivative financial instruments. The fair values indicated below are determined using observable market data including price quotations in active markets.

					Commodity Derivative Instruments		
($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swaps	Foreign Exchange Swaps	Electricity Swaps	Oil	Gas	Total
Deferred financial (credits)/assets, at December 31, 2007	$ (226)	$(89,439)	$ (425)	$ 450	$(56,783)[1]	$ 8,083[2]	$(138,340)
Change in fair value (credits)/asset	(2,488)[3]	17,167[4]	2,465[5]	(272)[6]	34,385[7]	5,903[7]	57,160
Deferred financial (credits)/assets, end of period	$(2,714)	$(72,272)	$2,040	$ 178	$(22,398)	$13,986	$ (81,180)
Balance sheet classification:							
Current (liability)/asset	$ –	$ –	$ –	$ 178	$(22,398)	$13,986	$ (8,234)
Non-current (liability)/asset	$(2,714)	$(72,272)	$2,040	$ –	$ –	$ –	$ (72,946)

(1) Includes the Focus opening credit balance at February 13, 2008 of $4,295.
(2) Includes the Focus opening credit balance at February 13, 2008 of $1,624.
(3) Recorded in interest expense.
(4) Recorded in foreign exchange expense (gain of $13,616) and interest expense (gain of $3,551).
(5) Recorded in foreign exchange expense.
(6) Recorded in operating expense.
(7) Recorded in commodity derivative instruments (see below).

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

($ thousands)	Three months ended September 30, 2008	2007	Nine months ended September 30, 2008	2007
(Gain)/loss due to change in fair value	**$(280,687)**	$ 3,799	**$ (40,288)**	$ 18,229
Net realized cash losses/(gain)	**60,035**	(7,384)	**135,030**	(14,162)
Commodity derivative instruments (gain)/loss	**$(220,652)**	$(3,585)	**$ 94,742**	$ 4,067

(d) Risk Management

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

i. Market Risk

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

Commodity Price Risk

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 October 28, 2008 are summarized below:

Crude Oil:

	Daily Volumes bbls/day	WTI US$/bbl Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term					
October 1, 2008 – December 31, 2008					
Collar	750	$ 77.00	$ 67.00	–	–
3-Way option	1,000	$ 84.00	$ 66.00	$ 50.00	–
3-Way option	1,000	$ 84.00	$ 66.00	$ 52.00	–
3-Way option	1,000	$ 86.00	$ 68.00	$ 52.00	–
3-Way option	1,000	$ 87.50	$ 70.00	$ 52.00	–
3-Way option	1,500	$ 90.00	$ 70.00	$ 60.00	–
Put Spread	1,500	–	$ 76.50	$ 58.00	–
Put Spread	1,500	–	$ 78.00	$ 58.00	–
Put	700	–	$ 86.10	–	–
Swap	750	–	–	–	$ 72.94
Swap	750	–	–	–	$ 74.00
Swap	750	–	–	–	$ 73.80
Swap	750	–	–	–	$ 73.35
Swap(2)	400	–	–	–	$ 78.53
Swap	1,500	–	–	–	$ 92.00
Swap(2)	400	–	–	–	$ 84.60
January 1, 2009 – December 31, 2009					
Collar	850	$100.00	$ 85.00	–	–
3-Way option	1,000	$ 85.00	$ 70.00	$ 57.50	–
3-Way option	1,000	$ 95.00	$ 79.00	$ 62.00	–
Put Spread	500	–	$ 92.00	$ 79.00	–
Put Spread	500	–	$ 92.00	$ 79.00	–
Swap	500	–	–	–	$100.05
Put	1,400	–	$122.00	–	–
Put(1)	500	–	$116.00	–	–
Put(1)	1,000	–	$120.00	–	–

(1) Financial contracts entered into during the third quarter of 2008.
(2) Acquired through the acquisition of Focus.

Natural Gas:

	Daily Volumes MMcf/day	AECO CDN$/Mcf				
		Purchased Call	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term						
October 1, 2008 – October 31, 2008						
Collar	6.6	–	$ 8.44	$ 7.17	–	–
Collar	6.6	–	$ 7.49	$ 6.44	–	–
Collar	5.7	–	$ 7.39	$ 6.65	–	–
Collar	11.4	–	$ 8.65	$ 7.60	–	–
Collar	2.8	–	$ 8.65	$ 7.49	–	–
Collar	2.8	–	$ 8.86	$ 7.91	–	–
Collar	2.8	–	$ 8.97	$ 7.91	–	–
3-Way option	5.7	–	$ 9.50	$ 7.54	$ 5.28	–
3-Way option	11.8	–	$ 7.91	$ 6.75	$ 5.49	–
3-Way option	11.8	–	$ 7.91	$ 6.75	$ 5.38	–
3-Way option	4.7	–	$ 8.23	$ 7.18	$ 5.28	–
Swap	4.7	–	–	–	–	$ 8.18
Swap	7.6	–	–	–	–	$ 6.79
Swap[2]	14.2	–	–	–	–	$ 6.70
Swap[2]	14.2	–	–	–	–	$ 7.17
Swap	2.8	–	–	–	–	$ 7.91
Swap	2.8	–	–	–	–	$ 7.87
Swap	2.8	–	–	–	–	$ 8.44
Swap	2.8	–	–	–	–	$ 8.49
Swap	5.7	–	–	–	–	$ 8.76
November 1, 2008 – March 31, 2009						
Collar	5.7	–	$ 9.50	$ 8.44	–	–
Call[1]	5.7	$ 9.50	–	–	–	–
3-Way option	5.7	–	$10.71	$ 7.91	$ 5.80	–
3-Way option	1.9	–	$10.55	$ 8.44	$ 6.33	–
3-Way option	5.7	–	$10.71	$ 8.44	$ 6.33	–
3-Way option	9.5	–	$12.45	$ 8.97	$ 7.39	–
3-Way option	4.7	–	$12.45	$ 8.97	$ 7.39	–
Put Spread	4.7	–	–	$ 8.97	$ 7.39	–
Put Spread	4.7	–	–	$ 8.97	$ 7.39	–
Swap	2.8	–	–	–	–	$ 9.42
Swap	2.8	–	–	–	–	$ 9.28
Swap	2.8	–	–	–	–	$ 9.34
Put	4.7	–	–	$11.34	–	–
Put	4.7	–	–	$11.61	–	–
Put[1]	4.7	–	–	$ 9.50	–	–
April 1, 2009 – October 31, 2009						
Swap	3.8	–	–	–	–	$ 7.86
Put Spread	2.8	–	–	$ 9.23	$ 7.65	–
Put Spread	2.8	–	–	$ 9.50	$ 7.91	–
Put Spread	5.6	–	–	$ 9.60	$ 7.91	–
Put[1]	9.5	–	–	$ 8.44	–	–
2008 – 2010						
Physical (escalated pricing)	2.0	–	–	–	–	$ 2.59

[1] Financial contracts entered into during the third quarter of 2008.
[2] Acquired through the acquisition of Focus.

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 September 30, 2008 on the Fund's outstanding commodity derivative contracts at that time with all other variables held constant:

	Increase/(decrease) to after-tax net income	
($ thousands)	25% decrease in forward prices	25% increase in forward prices
Crude oil derivative contracts	$53,452	$(57,242)
Natural gas derivative contracts	$10,135	$(14,657)

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 October 28, 2008 are summarized below:

Term	Volumes MWh	Price CDN$/MWh
October 1, 2008 – December 31, 2009	4.0	$74.50
October 1, 2008 – December 31, 2010[1]	4.0	$77.50

[1] Financial contracts entered into during the third quarter of 2008.

Currency Risk

The Fund is exposed to currency risk in relation to its U.S. dollar cash balances and U.S. dollar denominated senior unsecured notes. The Fund generally maintains a minimal amount of U.S. dollar cash and manages the currency risk relating to the senior unsecured notes through the currency derivative instruments that are detailed below.

Cross Currency Interest Rate Swap ("CCIRS")

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

Foreign Exchange Swaps

In September 2007 the Fund entered into foreign exchange swaps on US$54,000,000 of notional debt at an average CAD/US foreign exchange rate of 1.02. These foreign exchange swaps mature between October 2011 and October 2015 in conjunction with the principal repayments on the US$54,000,000 senior notes.

The following sensitivities show the impact to after-tax net income of the respective changes in the period end and applicable forward foreign exchange rates as at September 30, 2008, with all other variables held constant:

	Increase/(decrease) to after-tax net income	
($ thousands)	20% decrease in $CDN relative to $US	20% increase in $CDN relative to $US
Translation of US$54 million senior notes	$ (8,041)	$ 8,041
Translation of US$175 million senior notes	(26,452)	26,452
Total	$(34,493)	$34,493

($ thousands)	Increase/(decrease) to after-tax net income 20% decrease in $CDN relative to $US	20% increase in $CDN relative to $US
Foreign exchange swaps	$ 8,025	$ (8,025)
Cross currency interest rate swap(1)	25,518	(25,518)
Total	$33,543	$(33,543)

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

Interest Rate Risk

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

If interest rates change by 1%, either lower or higher, on our variable rate debt outstanding at September 30, 2008 with all other variables held constant, the Fund's after-tax net income for a quarter would change by $748,000.

The following sensitivities show the impact to after-tax net income of the respective changes in the applicable forward interest rates as at September 30, 2008, with all other variables held constant:

($ thousands)	Increase/(decrease) to after-tax net income 20% decrease in forward interest rates	20% increase in forward interest rates
Interest rate swaps	$ (381)	$ 381
Cross currency interest rate swap(1)	$2,028	$(2,028)

(1) Represents change due to interest rates only.

ii. Credit Risk

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

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

The Fund's maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets as well as the fair value of its derivative financial assets. At September 30, 2008 approximately 85% of our marketing receivables were with companies considered investment grade or just below investment grade. This level of credit concentration is typical of oil and gas companies of our size producing in similar regions.

At September 30, 2008 approximately $8,120,000 or 4% of our total accounts receivable are aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. The Fund actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production or net paying when the accounts are with joint venture partners. Should the Fund determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If the Fund subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. The Fund's allowance for doubtful accounts balance at September 30, 2008 is $4,300,000, which includes a $500,000 provision made during the third quarter. There were no accounts written off during the quarter.

iii. Liquidity Risk & Capital Management

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

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

Debt Levels

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

At September 30, 2008 the debt to cash flow ratio was 0.4x including the 12 months of trailing cash flow from Focus (September 30, 2007 – 0.7x). Enerplus' bank credit facilities and senior debenture covenants carry a maximum debt-to-cash flow ratio of 3.0x including cash flow from acquisitions on a proforma basis. Traditionally Enerplus has managed its debt levels such that the debt-to-cash flow ratio has been below 1.5x, which has provided flexibility in pursuing acquisitions and capital projects. Enerplus' five-year history of debt to cash flow is illustrated below:

	Q3/2008	Q2/2008	Q1/2008	2007	2006	2005	2004	2003
Debt-to-Cash Flow Ratio	0.4x	0.9x	1.0x	0.8x	0.8x	0.8x	1.1x	0.6x

At September 30, 2008 Enerplus had additional borrowing capacity of $1,122,688,000 under its $1,400,000,000 bank credit facility. The Fund may have the ability to increase the bank credit facility and borrowing capacity beyond this level, however increasing the credit facility at this time would result in increased fees. Enerplus does not have any subordinated or convertible debt outstanding at this time.

Capital Spending Plans

In 2008 Enerplus expects to spend approximately $545,000,000 on development capital activities. A portion of this capital spending is considered discretionary. There are limitations to changing the capital spending plans during a year as long project lead times, economies of scale, logistical considerations and partner commitments reduce the ability to adjust or down-size the capital program. Alternatively, the ability to rapidly increase spending may be limited by staff capacity, availability of services and equipment, access to sites, and regulatory approvals.

Distributions to Unitholders

Enerplus distributes a significant portion of its cash flow to its unitholders every month. These distributions are not guaranteed and the board of directors can change the amount at any time. In the past, in periods of sustained commodity price declines, distributions have been reduced. Similarly, in periods of sustained higher commodity prices, distributions have increased. To the extent that cash flow exceeds distributions additional funds are available to reduce debt, invest in capital development programs or finance acquisitions. The less cash required to finance these activities typically means more cash available for distributions and vice versa.

Enerplus does not forecast distribution levels as it is difficult to predict the direction of commodity prices. To the extent possible, distributions are set at a level that can be maintained for a sustained period. Historical performance has demonstrated that Enerplus investors do not reward short-term sporadic increases, nor do they appreciate a series of decreases. This unit price is important as equity is often issued in association with large acquisitions and the higher the unit price the less dilutive the equity issuance.

By paying distributions, we effectively earn a tax deduction against the corporate taxes in our underlying subsidiaries and pass along Canadian tax liability to our unitholders. If distributions are lowered and too much cash flow is retained within the structure there is a risk that tax obligations in the operating entities may be created thereby eroding the flow-through advantage of the trust structure.

Access to Capital Markets

Enerplus relies on both the debt and equity markets to manage its cost of capital and fund future opportunities. There are times when the cost and access to these markets will vary. For example, the ability to issue new equity at a reasonable cost is strongly influenced by the equity market's perceptions of energy prices, macroeconomic factors, and Enerplus' future prospects. Similarly, the ability to increase bank credit or issue debentures is dependent on the overall state of the credit markets, as well as creditors' perceptions of the energy sector and Enerplus' credit quality. In times of uncertainty cash flow may be preserved as a defense against capital market downturns rather than invested in capital programs or increasing distributions.

Enerplus currently has an NAIC2 rating on the senior unsecured debentures in the U.S. private debt markets.

Acquisition & Divestment Activity

In periods of market uncertainty and volatility, it is important to have a conservative balance sheet and access to capital markets to take advantage of acquisition opportunities as they arise. The Fund attempts to manage its capital in a manner that reflects the likelihood and magnitude of potential acquisitions and/or opportunities to dispose of non-core assets.

Enerplus was successful in disposing of its Joslyn interest during the quarter. The net proceeds of $502.0 million were used to repay debt, reinforcing Enerplus' borrowing capacity and enhancing the ability to fund future capital spending and acquisition activity.

Liability Maturity Analysis

The following tables detail the principal maturity analysis for the Fund's non-derivative financial liabilities at September 30, 2008:

		Payments Due by Period					Total Committed
($ thousands)	Total	2008	2009	2010	2011	2012	after 2013
Accounts Payable	$267,304[(1)]	$267,304	$ –	$ –	$ –	$ –	$ –
Distributions payable to unitholders	77,643[(2)]	77,643	–	–	–	–	–
Bank credit facility	277,312	–	–	277,312	–	–	–
Senior unsecured notes	325,565[(3)]	–	–	53,666	65,113	65,113	141,673
Total commitments	$947,824	$344,947	$ –	$330,978	$65,113	$65,113	$141,673

(1) Accounts payable are generally settled between 30 and 90 days from the balance sheet date.
(2) Distributions payable to unitholders are paid on the 20th day of the month following the balance sheet date.
(3) Includes the economic impact of derivative instruments directly related to the senior unsecured notes (CCIRS and foreign exchange swap).

It is Enerplus' intention to renew the bank credit facilities before or as they come due. Similarly, Enerplus expects that the senior unsecured notes will be replaced with replacement notes or bank debt as they become due. Enerplus cannot currently predict with any certainty the terms or rates at which such bank credit facilities and senior unsecured notes will be renewed, but such terms and rates may be less favorable than as currently exist. Over the long-term, Enerplus expects to balance short-term credit requirements with bank credit and to look to the term debt markets for longer-term credit support.

10. COMMITMENTS

During the quarter we acquired additional office space which results in the following total commitments for our office leases:

		Minimum Annual Commitment Each Year					Total Committed
($ thousands)	Total	2009	2010	2011	2012	2013	after 2013
Office leases	$69,493	$8,722	$12,266	$12,316	$12,400	$12,400	$11,389

BOARD OF DIRECTORS

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Calgary, Alberta

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Corporate Director
Calgary, Alberta

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

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Calgary, Alberta

Glen D. Roane[5][10]
Corporate Director
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Okotoks, Alberta

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Calgary, Alberta

Harry B. Wheeler[5][7]
Corporate Director
Calgary, Alberta

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

Robert L. Zorich[4][9]
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 & Environment Committee
[12] Chairman of the Health, Safety & Environment Committee

OFFICERS

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President & Chief Executive Officer

Garry A. Tanner
Executive Vice President & Chief Operating Officer

Ian C. Dundas
Senior Vice President, Business Development

Robert J. Waters
Senior Vice President & Chief Financial Officer

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

Ray J. Daniels
Vice President, 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, Marketing

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

Daniel M. Stevens
Vice President, Development Services

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 Oil & Gas Ltd.
Enerplus Commercial Trust
Enerplus Resources (USA) Corporation
FET Resources Ltd.
FET Energy Ltd.
FET Gas Production Ltd.

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

Sproule Associates Limited
Calgary, Alberta

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates 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	Alberta Energy Company interconnect with the Nova Gas System, the Canadian benchmark for natural gas pricing purposes
bbl(s)/day	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
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
GAAP	Generally accepted accounting principles
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf/day	thousand cubic feet per day
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf/day	million cubic feet per day
MWh	Megawatt hour(s) of electricity
NGLs	natural gas liquids
NYSE	New York Stock Exchange
SAGD	steam assisted gravity drainage
SEDAR	System for Electronic Document Analysis and Retrieval
TSX	Toronto Stock Exchange
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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