THE ENERGY OF

enerPLUS

SECOND QUARTER REPORT

Six months ended June 30, 2008

FINANCIAL & OPERATING HIGHLIGHTS

Selected Financial Results

(in Canadian dollars)	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Financial (000's)				
Cash Flow from Operating Activities	**$ 364,457**	$237,482	**$ 620,673**	$430,663
Cash Distributions to Unitholders[1]	**202,346**	162,607	**394,704**	320,278
Cash Withheld for Acquisitions and Capital Expenditures	**162,111**	74,875	**225,969**	110,385
Net Income	**112,230**	40,084	**233,624**	147,957
Debt Outstanding (net of cash)	**1,027,578**	657,945	**1,027,578**	657,945
Development Capital Spending	**88,008**	80,446	**214,270**	190,398
Acquisitions	**1,740**	204,016	**1,766,809**	267,394
Divestments	**86**	5,518	**2,208**	5,473
Actual Cash Distributions paid to Unitholders	**$ 1.26**	$ 1.26	**$ 2.52**	$ 2.52
Financial per Weighted Average Trust Units[2]				
Cash Flow from Operating Activities	**$ 2.22**	$ 1.85	**$ 3.98**	$ 3.42
Cash Withheld for Acquisitions and Capital Expenditures	**0.99**	0.58	**1.45**	0.88
Net Income	**0.68**	0.31	**1.50**	1.18
Payout Ratio[3]	**56%**	68%	**64%**	74%
Selected Financial Results per BOE[4]				
Oil & Gas Sales[5]	**$ 80.56**	$ 50.96	**$ 71.85**	$ 50.00
Royalties	**(15.14)**	(9.63)	**(13.46)**	(9.43)
Commodity Derivative Instruments	**(7.03)**	(0.15)	**(4.35)**	0.45
Operating Costs	**(9.43)**	(9.80)	**(9.21)**	(9.16)
General and Administrative	**(1.67)**	(1.94)	**(1.75)**	(1.93)
Interest and Other Income and Foreign Exchange	**(1.32)**	(1.36)	**(1.10)**	(1.34)
Taxes	**(1.78)**	(0.43)	**(1.49)**	(0.35)
Restoration and Abandonment	**(0.52)**	(0.51)	**(0.51)**	(0.48)
Cash Flow from Operating Activities before changes in non-cash working capital	**$ 43.67**	$ 27.14	**$ 39.98**	$ 27.76
Weighted Average Number of Trust Units Outstanding Including Equivalent Exchangeable Limited Partnership Units (thousands)	**164,483**	128,361	**155,984**	125,849
Debt/Trailing 12 Month Cash Flow Ratio[6]	**0.9x**	0.7x	**0.9x**	0.7x

Selected Operating Results

	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Average Daily Production				
Natural gas (Mcf/day)	**359,349**	264,946	**333,559**	270,300
Crude oil (bbls/day)	**35,486**	34,178	**34,376**	34,869
NGLs (bbls/day)	**4,810**	4,143	**4,712**	4,325
Total (BOE/day)	**100,188**	82,478	**94,681**	84,244
% Natural gas	**60%**	54%	**59%**	53%
Average Selling Price[5]				
Natural gas (per Mcf)	**$ 9.87**	$ 7.04	**$ 8.79**	$ 7.13
Crude oil (per bbl)	**114.04**	61.93	**100.47**	59.56
NGLs (per bbl)	**80.55**	53.34	**75.29**	48.55
US$ exchange rate	**0.99**	0.91	**0.99**	0.88
Net Wells drilled	**72**	36	**197**	75
Success Rate	**100%**	100%	**100%**	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.
(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 June 30, 2008	TSX – ERF.un (CDN$)	NYSE – ERF (US$)
High	$49.85	$50.63
Low	$43.44	$42.43
Close	$47.18	$46.24

2008 Cash Distributions Per Trust Unit

Production Month	Payment Month	CDN$	US$
First Quarter Total		**$1.26**	**$1.24**
April	June	$0.42	$0.41
May	July	0.42	0.42
June	August	0.42	0.41*
Second Quarter Total		**$1.26**	**$1.24**
Total Year-to-Date		**$2.52**	**$2.48**

* Calculated using a Canadian/US$ exchange rate of 1.02

PRESIDENT'S MESSAGE

With crude oil prices reaching an all-time high, strong natural gas prices and record production volumes, I am pleased to report that Enerplus has achieved one of the most successful quarters in our history.

Daily production volumes averaged 100,188 BOE/day during the quarter, reflecting the full integration of the Focus assets within our portfolio, the earlier than expected return of our Giltedge production and the continued success of our development capital program. We continue to reap the benefits of the Focus Energy Trust acquisition with the marked rise in natural gas prices in 2008. Both the Shackleton and Tommy Lakes properties are performing better than expected. Cash flow from operating activities was $364.5 million, up 53% over the same period last year and our payout ratio was 56%. Including development capital expenditures, our adjusted payout ratio for the second quarter was approximately 80% indicating that our cash flow was more than covering both distributions and capital spending for the quarter.

In addition to our operational achievements, subsequent to quarter end we successfully divested our working interest in the Joslyn oil sands lease for net proceeds of approximately $500 million compared to our investment of approximately $115 million. We have used the proceeds to further strengthen our balance sheet with a resulting debt-to-cash flow ratio of approximately 0.4x. We continue to hold an approximate 12% interest in Laricina Energy Ltd., a private company holding significant resources in the Alberta oil sands with future in-situ development potential.

The development of our operated oil sands lease at Kirby also continues to play a pivotal role in our future. We have completed the analysis of the core holes drilled in our winter delineation program. Preliminary estimates from our third party reserves engineers indicate a revised best estimate contingent resource of approximately 414 million barrels. This represents an increase of 170 million barrels (70%) over our original estimate of 244 million barrels for the entire lease. Planning work is currently underway on our second winter drilling program which will help to further define the potential in the lease. We continue to prepare our regulatory application for the first 10,000 bbl/day project and expect to file the application later this fall. In addition, I am happy to announce that we have assembled our entire oil sands leadership team and have seen a significant increase in our oil sands staff to help us move the Kirby project forward.

Crude oil prices continued to lead the way with a 39% increase during the quarter. This rise was primarily due to lower than expected inventories, continued weakness in the U.S. dollar and continued concerns around security of supply out of politically volatile regions. We realized an average crude price of approximately $114.00/bbl, 84% higher than this time last year. Alberta natural gas prices were up over 30% from the first quarter primarily due to lower storage inventories, strong crude oil prices and lower liquefied natural gas imports into the U.S. We realized an average price of $9.87/Mcf for the quarter, over 40% higher than the same period last year. Since the end of the quarter, data indicating lower global demand for oil and robust U.S. natural gas supply growth have caused prices to retract sharply. Forward prices for crude oil are 12% lower and natural gas prices are 31% lower than at the end of June. The increase in commodity prices did result in higher costs for our price risk management program this quarter as we incurred cash losses of $64 million in the quarter due to commodity prices exceeding our caps and fixed price contracts.

2008 Production and Development Activity

	Three months ended June 30,				Six months ended June 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	25,438	$ 23.9	68	67.4	22,939	$ 46.3	217	159.4
Crude Oil Waterfloods	16,484	10.7	–	–	15,777	27.9	22	10.5
Deep Tight Gas	15,613	8.9	2	1.2	14,407	31.8	30	5.2
Bakken Oil	11,346	13.5	4	2.9	11,124	33.0	8	6.0
Other Conventional Oil & Gas	31,307	18.1	26	0.8	30,434	40.9	79	16.0
Total Conventional	**100,188**	**75.1**	**100**	**72.3**	**94,681**	**179.9**	**356**	**197.1**
Oil Sands								
Kirby	–	3.9	–	–	–	24.5	–	–
Joslyn	–	8.5	–	–	–	9.2	–	–
Laricina	–	0.5	–	–	–	0.7	–	–
Total Oil Sands	–	**12.9**	–	–	–	**34.4**	–	–
Total	**100,188**	**88.0**	**100**	**72.3**	**94,681**	**214.3**	**356**	**197.1**

* Drilling totals do not include delineation wells at Kirby or service wells drilled during the quarter

Drilling success rate year-to-date: 100%

Weather delays, a reduction in non-operated spending and lower than budgeted spending at Joslyn resulted in slightly lower than planned development capital spending of $88 million in the quarter. Redeployment of approximately $40 million of development capital from oil sands (Joslyn) to our conventional business, an increase in other operated conventional development spending across our resource plays and an expectation of increased non-operated spending for the balance of the year allows us to maintain our annual development capital spending guidance of $580 million. We are raising our guidance on operating costs for the year to approximately $9.00/BOE from $8.65/BOE, primarily due to increased service rig activity on optimization efforts in the U.S. and additional costs for fuel and supplies. Although the well optimization efforts in the U.S. have increased our overall operating costs, we are pleased with the production performance from our Bakken Oil resource play as a result of these activities.

Approximately 60% of our capital spending this quarter was directed toward crude oil development opportunities, although the majority of the wells drilled were in our shallow gas resource play. Wet weather caused a delay on some of our development capital expenditures in the quarter but significant drilling and tie-ins prior to break-up in the first quarter and better than expected production performance in key areas throughout the second quarter resulted in strong overall operational performance. Efficient planning and execution of turnarounds by our staff minimized facility downtime, offset weather delays and also helped us meet our production targets.

In our shallow gas resource play, we invested nearly a third of our quarterly conventional spending by drilling 68 gross wells in the second quarter. At Shackleton, we drilled 48 wells and are expanding our development program for the rest of the year to drill 60 additional wells above our original plans, significantly increasing recompletion work and adding more compression by the end of 2008.

Our Giltedge waterflood property, which was shut down late in 2007 due to a facility fire and had been partially operating with temporary facilities early in 2008, resumed full operations on April 14, 2008. The restart was two weeks earlier than we anticipated and production has returned to near normal levels.

Optimization efforts in the U.S. continued during the second quarter and we anticipate resuming our refrac and 3rd well per section program in the third quarter, increasing our development capital spending in the U.S. throughout the balance of the year.

Our safety performance in the field for both employees and contractors improved this quarter over last with no medical aid incidents. This was due primarily to our increased emphasis on motor vehicle safety, proactive hazard identification and improvements in near miss reporting.

Canadian Federal Tax Legislation

On July 14, 2008, the Canadian Department of Finance released draft amendments to the Canadian Income Tax Act which included provisions to facilitate the tax efficient conversion of a specified investment flow through ("SIFT") trust into a corporation. These draft provisions are designed to ensure that the conversion of a trust to a corporation can be structured in such a manner that neither the trust nor its unitholders will be subject to Canadian tax on the transaction. We believe that any corporate conversion transaction should be tax deferred for our U.S. unitholders as well. The Department of Finance is accepting comments on these proposals until September 15, 2008 after which it intends to present the amendments as part of a tax reform bill in the Fall of 2008.

As we have stated since the 2006 trust taxation announcement, we believe that there is value in retaining the trust structure until the end of 2010. We currently do not foresee any compelling reasons to make major changes to our corporate structure before 2011.

Looking Ahead

With the exception of a small increase in operating costs, we remain on track to meet our operational guidance for 2008. We continue to expect to produce an average of 98,000 BOE/day for the year with an exit rate of 100,000 BOE/day. We will continue to focus on operational excellence and execution. This focus combined with the flexibility of a strong balance sheet will allow us to continue to develop our existing conventional resource plays, fully develop our growing Kirby oil sands resource and pursue high quality acquisitions to add accretive cash flow to our business.

Given the strength in commodity prices, the performance of our operations and the health of our balance sheet, I am pleased to announce that effective September 20, 2008, we will be increasing the monthly cash distribution to unitholders to $0.47/unit.

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 August 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 six months ended June 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

Production for the second quarter was in-line with our expectations averaging 100,188 BOE/day. Cash flow from operating activities totaled $364.5 million representing an increase of $108.3 million or 42% from the first quarter of 2008 and $127.0 million or 53% from the second quarter of 2007. The increases are mainly due to higher commodity prices along with increased production as a result of the acquisition of Focus Energy Trust ("Focus"). The higher commodity prices also impacted our price risk management costs as we incurred cash losses of $64.0 million and non-cash losses of $161.0 million due to higher forward commodity prices at quarter end.

For the second quarter of 2008 our development capital spending was $88.0 million as we drilled 72 net wells with a 100% success rate. Operating costs were slightly higher than anticipated due to optimization work in the United States. All of our 2008 guidance targets remain unchanged with the exception of our annual operating costs which we are increasing to $9.00/BOE, primarily as a result of our U.S. optimization efforts.

On July 31, 2008, subsequent to quarter end, we successfully disposed of our Joslyn oil sands lease ("Joslyn") for net proceeds of approximately $500 million. The proceeds have been used to pay down bank debt which further strengthens our balance sheet and positions us well for future growth. Given the strength in commodity prices and the performance of our operations we are increasing monthly cash distributions to $0.47/unit effective September 20, 2008.

Results of Operations

Production

Production in the second quarter of 2008 was in-line with our expectations averaging 100,188 BOE/day, an increase of 12% from 89,150 BOE/day in the first quarter of 2008. For the three and six months ended June 30, 2008 production increased 21% and 12% respectively, compared to the same periods in 2007. The increases are primarily due to the additional production from the Focus assets acquired on February 13, 2008.

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

	Three months ended June 30,			Six months ended June 30,		
Daily Production Volumes	2008	2007	% Change	2008	2007	% Change
Natural gas (Mcf/day)	359,349	264,946	36%	333,559	270,300	23%
Crude oil (bbls/day)	35,486	34,178	4%	34,376	34,869	(1)%
Natural gas liquids (bbls/day)	4,810	4,143	16%	4,712	4,325	9%
Total daily sales (BOE/day)	100,188	82,478	21%	94,681	84,244	12%

Based on the results of our second quarter we continue to expect 2008 annual production volumes to average 98,000 BOE/day and our 2008 exit rate to be approximately 100,000 BOE/day.

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 for the three and six months ended June 30, 2008 and 2007. It also compares the benchmark price indices for the same periods:

	Three months ended June 30,			Six months ended June 30,		
Average Selling Price[1]	2008	2007	% Change	2008	2007	% Change
Natural gas (per Mcf)	$ 9.87	$ 7.04	40%	$ 8.79	$ 7.13	23%
Crude oil (per bbl)	$114.04	$61.93	84%	$100.47	$59.56	69%
Natural gas liquids (per bbl)	$ 80.55	$53.34	51%	$ 75.29	$48.55	55%
Per BOE	$ 80.56	$50.96	58%	$ 71.85	$50.00	44%
Average Benchmark Pricing						
AECO natural gas – monthly index (CDN$/Mcf)	$ 9.35	$ 7.37	27%	$ 8.24	$ 7.42	11%
AECO natural gas – daily index (CDN$/Mcf)	$ 10.22	$ 7.07	45%	$ 9.06	$ 7.23	25%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	$ 10.80	$ 7.56	43%	$ 9.43	$ 7.26	30%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	$ 10.91	$ 8.31	31%	$ 9.53	$ 8.25	16%
WTI crude oil (US$/bbl)	$123.98	$65.03	91%	$110.95	$61.65	80%
WTI crude oil CDN$ equivalent (CDN$/bbl)	$125.23	$71.46	75%	$112.07	$70.06	60%
CDN$/US$ exchange rate	0.99	0.91	9%	0.99	0.88	13%

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

During the quarter the AECO natural gas price rose 30% from a low of $9.08/Mcf to a high of $11.80/Mcf. This price increase during the second quarter was supported by the strength of crude oil, lower storage inventories, lower liquefied natural gas imports into the U.S. and weather concerns.

We realized an average price on our natural gas of $9.87/Mcf (net of transportation costs) during the three months ended June 30, 2008, an increase of 40% from $7.04/Mcf for the same period in 2007. For the six months ended June 30, 2008 we realized a 23% increase in our average price of $8.79/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 40% and 23% increases for the three and six month periods ended June 30, 2008 are comparable to the changes experienced at AECO.

Crude oil prices rose steadily during the second quarter as a result of low inventories, a weak U.S. dollar and supply risks related to Nigeria and Iran. The average price we received for our crude oil during the three months ended June 30, 2008 increased 84% to $114.04/bbl (net of transportation costs) compared to $61.93/bbl during the same period in 2007. Similarly, the West Texas Intermediate ("WTI") crude oil benchmark price, in Canadian dollars, increased 75% from the corresponding period in 2007. For the six months ended June 30, 2008 our crude oil price increased 69% to $100.47/bbl (net of transportation costs), while the WTI benchmark, in Canadian dollars, increased 60%. Medium and heavy differentials narrowed as a percentage of WTI compared to the prior period of 2007.

The Canadian dollar strengthened against the U.S. dollar during the three and six months ended June 30, 2008 compared to the same periods in 2007. As most of our crude oil and natural gas is priced in reference to U.S. dollar denominated benchmarks, this movement in the exchange rate reduced the Canadian dollar prices that we would have otherwise realized.

Price Risk Management

We have developed a price risk management framework to respond to the volatile commodity price environment in a prudent manner. Consideration is given to our overall financial position together with the economics of our development capital program and acquisitions. Consideration is also given to the upfront 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. With respect to our natural gas and crude oil hedges for 2008, our overall hedge position was influenced by our desire to provide a level of protection to the downside on cash flow.

Considering all financial contracts transacted as of July 25, 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 some of our consumption in the Alberta power market through to December 31, 2009. 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 July 25, 2008, expressed as a percentage of our forecasted net production volumes:

	Natural Gas (CDN$/Mcf)			Crude Oil (US$/bbl)	
	July 1, 2008 – October 31, 2008	November 1, 2008 – March 31, 2009	April 1, 2009 – October 31, 2009	July 1, 2008 – December 31, 2008	January 1, 2009 – December 31, 2009
Floor Prices (puts)	$7.09	$ 9.20	$9.48	$72.09	$ 94.62
% (net of royalties)	25%	21%	4%	34%	21%
Fixed Price (swaps)	$7.44	$ 9.35	$7.86	$79.97	$100.05
% (net of royalties)	20%	3%	2%	18%	2%
Capped Price (calls)	$8.25	$11.24	–	$85.48	$ 92.98
% (net of royalties)	25%	12%	–	22%	11%

Based on weighted average price (before premiums), estimated average annual production of 98,000 BOE/day and assuming a royalty rate of 19% for 2008. For 2009 we have assumed a 26% royalty rate reflecting the increased royalties for Alberta production at the current forward commodity price levels.

Accounting for Price Risk Management

During the second quarter of 2008 our price risk management program incurred cash losses of $16.0 million on our natural gas contracts and $48.0 million on our crude oil contracts, compared to cash losses of $0.8 million and $0.3 million respectively during the second quarter of 2007. For the six months ended June 30, 2008 we experienced cash losses of $11.8 million on our natural gas contracts and cash losses of $63.2 million on our crude oil contracts, compared to a loss of $1.3 million and a gain of $8.1 million respectively for the same period in 2007. The increase in cash losses for the three and six months ended June 30, 2008 is the result of commodity prices rising above our swap and sold call positions.

At June 30, 2008 both the current and forward commodity prices for crude oil and natural gas were at all time highs which impacted the fair value of our commodity derivative instruments. The fair value of our natural gas and crude oil derivative instruments, net of premiums, represented losses of $89.9 million and $199.2 million respectively at June 30, 2008. These loss positions are based on forward natural gas and crude oil prices and are recorded as current deferred financial credits on our balance sheet. In comparison, at March 31, 2008 the fair value of our natural gas and crude oil derivative instruments represented losses of $50.2 million and $77.9 million respectively. The change in the fair value of our commodity derivative instruments during the second quarter of 2008 resulted in unrealized losses of $39.7 million for natural gas and $121.3 million for crude oil. For the six months ended June 30, 2008 the change in fair value of our commodity derivative instruments resulted in unrealized losses of $98.0 million for natural gas and $142.4 million for crude oil. See Note 9 for details.

Between June 30, 2008 and July 25, 2008 the market prices for crude oil decreased by 12% while natural gas prices decreased by 31%. If the forward market remains at these lower levels relative to June 30, 2008 we would expect to record recoveries on our unrealized non-cash losses in subsequent quarters.

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

Risk Management Costs ($ millions, except per unit amounts)	Three months ended June 30, 2008		Three months ended June 30, 2007	
Cash losses:				
Natural gas	$ (16.0)	$ (0.49)/Mcf	$ (0.8)	$(0.03)/Mcf
Crude oil	(48.0)	(14.86)/bbl	(0.3)	(0.10)/bbl
Total Cash losses	$ (64.0)	$ (7.03)/BOE	$ (1.1)	$(0.15)/BOE
Non-cash (losses)/gains on financial contracts:				
Change in fair value – natural gas	$ (39.7)	$ (1.21)/Mcf	$ 25.4	$ 1.05/Mcf
Change in fair value – crude oil	(121.3)	(37.56)/bbl	(6.3)	(2.03)/bbl
Total non-cash (losses)/gains	$(161.0)	$(17.65)/BOE	$ 19.1	$ 2.54/BOE
Total (losses)/gains	$(225.0)	$(24.68)/BOE	$ 18.0	$ 2.39/BOE

Risk Management Costs ($ millions, except per unit amounts)	Six months ended June 30, 2008		Six months ended June 30, 2007	
Cash (losses)/gains:				
Natural gas	$ (11.8)	$ (0.19)/Mcf	$ (1.3)	$(0.03)/Mcf
Crude oil	(63.2)	(10.10)/bbl	8.1	1.28/bbl
Total Cash (losses)/gains	$ (75.0)	$ (4.35)/BOE	$ 6.8	$ 0.45/BOE
Non-cash (losses)/gains on financial contracts:				
Change in fair value – natural gas	$ (98.0)	$ (1.61)/Mcf	$ 4.8	$ 0.10/Mcf
Change in fair value – crude oil	(142.4)	(22.77)/bbl	(19.2)	(3.04)/bbl
Total non-cash losses	$(240.4)	$(13.95)/BOE	$(14.4)	$(0.95)/BOE
Total losses	$(315.4)	$(18.30)/BOE	$ (7.6)	$(0.50)/BOE

Cash Flow Sensitivity

The sensitivities below reflect the estimated impact on cash flow per trust unit for the remaining two quarters of 2008 and include the commodity contracts described in Note 9 as well as the impact of 2008 forward market prices as at July 25, 2008. To the extent the market price of crude oil and natural gas change significantly from the July 25, 2008 levels, the sensitivities will no longer be relevant as the effect of our commodity contracts will change.

Sensitivity Table	Estimated Effect on 2008 Cash Flow per Trust Unit[(1)]
Change of $0.15 per Mcf in the price of AECO natural gas	$0.03
Change of US$1.00 per barrel in the price of WTI crude oil	$0.02
Change of 1,000 BOE/day in production	$0.07
Change of $0.01 in the US$/CDN$ exchange rate	$0.06
Change of 1% in interest rate	$0.03

(1) Assumes constant working capital and 164,709,000 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 higher during the second quarter of 2008 compared to the first quarter of 2008 due to an increase in commodity prices and a full quarter of production from the Focus assets.

Crude oil and natural gas revenues for the three months ended June 30, 2008 were $734.4 million ($741.5 million, net of $7.1 million transportation) compared to $382.5 million ($387.9 million, net of $5.4 million transportation) for the same period in 2007. For the six months ended June 30, 2008 revenues were $1,238.1 million ($1,251.5 million, net of $13.4 million transportation) compared to $762.5 million ($773.8 million, net of $11.3 million transportation) during the same period in 2007.

The majority of the increase in revenues of $351.9 million or 92% and $475.6 million or 62% for the three and six months ended June 30, 2008 compared to the same period in 2007 was due to higher commodity prices.

The following table summarizes the changes in sales revenue:

Analysis of Sales Revenue[1] ($ millions)	Crude Oil	NGLs	Natural Gas	Total
Quarter ended June 30, 2007	$192.6	$20.1	$169.8	$ 382.5
Price variance[1]	168.3	12.0	96.4	276.7
Volume variance	7.4	3.3	64.5	75.2
Quarter ended June 30, 2008	**$368.3**	**$35.4**	**$330.7**	**$ 734.4**

($ millions)	Crude Oil	NGLs	Natural Gas	Total
Year-to-date ended June 30, 2007	$375.9	$38.0	$348.6	$ 762.5
Price variance[1]	256.0	23.0	106.8	385.8
Volume variance	(3.3)	3.6	89.5	89.8
Year-to-date ended June 30, 2008	**$628.6**	**$64.6**	**$544.9**	**$1,238.1**

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

Other Income

Other income for the three and six months ended June 30, 2008 was $0.4 million and $15.5 million respectively, compared to $0.3 million and $14.4 million for the same periods in 2007. Included in the first six months of 2008 was a gain of $8.3 million on the sale of certain marketable securities, as well as interim payments for 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 certain marketable securities.

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three and six months ended June 30, 2008 royalties were $138.0 million and $231.9 million respectively, both approximately 19% of oil and gas sales net of transportation. For the three and six months ended June 30, 2007 royalties were $72.2 million and $143.8 million, both approximately 19% of oil and gas sales net of transportation respectively. Increases in royalties for the three and six months ended June 30, 2008 of $65.8 million and $88.1 million respectively, compared to the same periods in 2007 were the result of higher commodity prices and increased production. We continue to expect royalties to be approximately 19% of oil and gas sales net of transportation during 2008.

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 of $130.00/bbl crude oil and $10.00/Mcf natural gas, and relative to Enerplus' current properties and production profile, we estimate the NRF will result in an average 2009 royalty rate for the Fund of approximately 26% of oil and gas sales, net of transportation costs.

As at the date of this MD&A the Alberta government had not yet made the necessary legislative and administrative changes to implement the NRF. The NRF announcement can be found on the Alberta government's website at www.gov.ab.ca.

Operating Expenses

Operating expenses during the second quarter of 2008 were $9.43/BOE or 6% higher than the first quarter of 2008. This increase can be attributed to additional service rig activity related to optimization work on our U.S. properties.

Operating expenses for the three months ended June 30, 2008 were $86.0 million or $9.43/BOE compared to $72.8 million or $9.69/BOE for the second quarter of 2007. For the six months ended June 30, 2008 operating costs were $158.0 million or $9.17/BOE compared to $138.8 million or $9.10/BOE for the same period in 2007. Operating expenses are generally in-line with our expectations however we have experienced a slight increase in costs for fuel and supplies which can be attributed to higher oil prices. In addition, we are continuing to spend more on optimization efforts on our U.S. properties which has resulted in increased production.

As a result of the increased costs to date we are raising our annual guidance for operating costs from $8.65/BOE to $9.00/BOE.

General and Administrative Expenses ("G&A")

During the second quarter of 2008 G&A expenses decreased 6% per BOE to $1.90/BOE compared to $2.03/BOE for the first quarter of 2008.

G&A expenses for the three months ended June 30, 2008 were $17.3 million or $1.90/BOE compared to $16.7 million or $2.22/BOE for the second quarter of 2007. G&A expenses totaled $33.8 million or $1.96/BOE for the six months ended June 30, 2008 compared to $33.8 million or $2.21/BOE for the same period in 2007. G&A expenses remained relatively unchanged year-over-year however the reduction on a $/BOE basis compared to 2007 is primarily due to the additional volumes associated with the Focus acquisition.

For the three and six months ended June 30, 2008 our G&A expenses included non-cash charges of $2.1 million or $0.23/BOE and $3.6 million or $0.21/BOE respectively, compared to $2.1 million or $0.28/BOE and $4.2 million or $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 June 30,		Six months ended June 30,	
($ millions)	**2008**	2007	**2008**	2007
Cash	**$15.2**	$14.6	**$30.2**	$29.6
Trust unit rights incentive plan (non-cash)	**2.1**	2.1	**3.6**	4.2
Total G&A	**$17.3**	$16.7	**$33.8**	$33.8
(Per BOE)	**2008**	2007	**2008**	2007
Cash	**$1.67**	$1.94	**$1.75**	$1.93
Trust unit rights incentive plan (non-cash)	**0.23**	0.28	**0.21**	0.28
Total G&A	**$1.90**	$2.22	**$1.96**	$2.21

We are maintaining our guidance for G&A expenses at $2.20/BOE, which includes non-cash G&A costs of approximately $0.20/BOE.

Interest Expense

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

Interest on long-term debt excluding non-cash charges totaled $12.9 million and $26.2 million for the three and six months ended June 30, 2008, compared to $9.7 million and $19.5 million respectively for the same periods in 2007. The increases in 2008 are due to higher average outstanding indebtedness as a result of the Focus acquisition, partially offset by lower interest rates.

Non-cash interest charges totaled $6.4 million and nil for the three and six months ended June 30, 2008, compared to $2.1 million and $0.5 million respectively 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 the cash and non-cash interest expense recorded:

Interest Expense ($ millions)	Three months ended June 30, 2008	2007	Six months ended June 30, 2008	2007
Interest on long-term debt	**$12.9**	$ 9.7	**$26.3**	$19.5
Non-cash interest loss	**6.4**	2.1	**–**	0.5
Total Interest Expense	**$19.3**	$11.8	**$26.3**	$20.0

At June 30, 2008 approximately 15% of our debt was based on fixed interest rates while 85% had floating interest rates. In comparison, at June 30, 2007 approximately 20% of our debt was based on fixed interest rates and 80% was floating.

Capital Expenditures

During the three and six months ended June 30, 2008 we spent $88.0 million and $214.3 million on capital development respectively, compared to $80.4 million and $190.4 million during the same periods in 2007. The increase experienced during 2008 is largely due to drilling activities associated with our shallow gas properties and additional activity on our Focus assets. To date we have achieved a 100% success rate with our drilling program on 197 net wells.

Corporate acquisitions for the six months ending June 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 acquisitions for the three and six months ended June 30, 2008 totaled $1.8 million and $9.3 million respectively, compared to $204.0 million and $267.4 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 ($ millions)	Three months ended June 30, 2008	2007	Six months ended June 30, 2008	2007
Development expenditures	**$56.0**	$ 69.4	**$ 165.3**	$160.2
Plant and facilities	**32.0**	11.0	**49.0**	30.2
Development Capital	**88.0**	80.4	**214.3**	190.4
Office	**2.0**	1.6	**3.6**	3.0
Sub-total	**90.0**	82.0	**217.9**	193.4
Property acquisitions[1]	**1.8**	204.0	**9.3**	267.4
Corporate acquisitions	**–**	–	**1,757.5**	–
Property dispositions[1]	**(0.1)**	(5.5)	**(2.2)**	(5.5)
Total Net Capital Expenditures	**$91.7**	$280.5	**$1,982.5**	$455.3
Capital Expenditures financed with cash flow	**$91.7**	$ 74.9	**$ 226.0**	$110.4
Capital Expenditures financed with debt and equity	**–**	205.6	**1,756.5**	344.9
Total Net Capital Expenditures	**$91.7**	$280.5	**$1,982.5**	$455.3

(1) Net of post-closing adjustments.

Our year-to-date development capital spending is slightly behind schedule and although we disposed of our interest in Joslyn subsequent to the quarter end, we are maintaining our 2008 guidance of $580 million. Approximately $40 million of planned spending for Joslyn will be redirected to conventional development capital spending during the remainder of the year. Due to the timing of these additional conventional capital expenditures we are not expecting a significant impact to 2008 production volumes.

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 June 30, 2008 capitalized costs life-to-date for Joslyn including other minor interests were $121.2 million and for Kirby were $229.9 million for a combined total of $351.1 million.

During the second quarter of 2008 we capitalized costs of $3.9 million associated with advancing our regulatory application for our Kirby project.

On July 31, 2008 we disposed of our interest in Joslyn for total cash consideration of approximately $500 million. Proceeds from the disposition have been used to pay down debt, improving our debt-to-cash flow ratio which reinforces our borrowing capacity, supports our ability to fund future development capital and acquisition activities and minimizes the need to issue additional equity.

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 the 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 June 30, 2008, DDA&A increased to $18.93/BOE compared to $15.58/BOE during the corresponding period in 2007. For the six months ended June 30, 2008 DDA&A increased to $18.12/BOE compared to $15.48/BOE during the corresponding period in 2007. The increase is primarily due to additional PP&E and production as a result of the Focus acquisition.

No impairment of the Fund's assets existed at June 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 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 and such obligations are included on the Fund's balance sheet.

The Fund has estimated the net present value of its total asset retirement obligations to be approximately $203.4 million at June 30, 2008 compared to $165.7 million at December 31, 2007. The increase of $37.7 million relates primarily to the acquisition of Focus. 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 June 30,		Six months ended June 30,	
($ millions)	**2008**	2007	**2008**	2007
Amortization of the asset retirement cost	**$5.1**	$3.3	**$ 9.8**	$ 6.7
Accretion of the asset retirement obligation	**3.1**	1.6	**5.6**	3.3
Total Amortization and Accretion	**$8.2**	$4.9	**$15.4**	$10.0
Asset Retirement Obligations Settled	**$4.8**	$3.8	**$ 8.8**	$ 7.1

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. The balance will be realized when future income tax assets and liabilities are realized or settled.

Our future income tax recovery was $50.4 million for the quarter ended June 30, 2008 compared to an expense of $71.0 million for the same period in 2007. During the second quarter of 2007, the Canadian Federal Government enacted the new specified investment flow through ("SIFT") tax on publicly traded income trusts effective January 1, 2011 which resulted in a one-time future income tax expense of $78.1 million. After consideration of the SIFT tax, the increased recovery in 2008 is due to higher income at the trust level and the recording of a future tax asset relating to a previously unrecognized tax pool.

Subsequent to June 30, 2008, the Department of Finance issued draft amendments to the Income Tax Regulations regarding the provincial tax rate for 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. The amendments were not considered substantively enacted at June 30, 2008. As a result there was no consequential impact on future income taxes in the second quarter however this will result in a future income tax recovery when enacted.

On July 14, 2008, the Department of Finance released draft legislative proposals which included proposed amendments which would allow a SIFT to convert into a corporation on a tax efficient basis without adverse Canadian tax consequences for the trust or its Canadian unitholders. We believe that the trust conversion under the proposed rules would qualify as a U.S. tax deferred transaction for our U.S. unitholders as well. The Canadian Department of Finance is accepting comments on these proposals until September 15, 2008 and intends to introduce the amendments into Parliament later this year. We are currently reviewing the legislative proposals to determine the impact to Enerplus should we eventually decide to 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 on February 13, 2008. This liability was included in Focus' assumed working capital and was paid in April 2008. We expect to recover these taxes over the next twelve months and as such we have recorded a cash income tax recovery of $7.9 million for six months ended June 30, 2008.

The amount of current taxes recorded in the year with respect to our U.S. operations is dependent upon income levels, and the timing of both capital expenditures and the repatriation of funds to Canada. For the three and six months ended June 30, 2008 our U.S. operations incurred taxes (income and withholding) in the amount of $21.5 million and $33.7 million respectively, compared to $3.2 and $5.3 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 second quarter of 2008 was $112.2 million or $0.68 per trust unit compared to $40.1 million or $0.31 per trust unit in the same period for 2007. Net income for the six months ended June 30, 2008 was $233.6 million or $1.50 per trust unit compared to $148.0 million or $1.18 per trust unit for the same period in 2007. The $85.6 million increase in net income for the six months ended was primarily due to an increase in oil and gas sales of $477.7 million which was offset by an increase in royalties of $88.1 million and an increase in commodity derivative instrument losses of $307.7 million.

Cash Flow from Operating Activities

Cash flow for the three and six months ended June 30, 2008 was $364.5 million ($2.22 per trust unit) and $620.7 million ($3.98 per trust unit) respectively, compared to $237.5 million ($1.85 per trust unit) and $430.7 million ($3.42 per trust unit) for the three and six months ended June 30, 2007. The increases per trust unit were primarily a result of strong commodity prices combined with an increase in production due to the Focus acquisition.

Selected Financial Results

Per BOE of production (6:1)	Three months ended June 30, 2008 Operating Cash Flow[1]	Non-Cash & Other Items	Total	Three months ended June 30, 2007 Operating Cash Flow[1]	Non-Cash & Other Items	Total
Production per day			100,188			82,478
Weighted average sales price[2]	$ 80.56	$ –	$ 80.56	$50.96	$ –	$ 50.96
Royalties	(15.14)	–	(15.14)	(9.63)	–	(9.63)
Commodity derivative instruments	(7.03)	(17.65)	(24.68)	(0.15)	2.54	2.39
Operating costs	(9.43)	–	(9.43)	(9.80)	0.11	(9.69)
General and administrative	(1.67)	(0.23)	(1.90)	(1.94)	(0.28)	(2.22)
Interest expense, net of other income	(1.37)	(0.70)	(2.07)	(1.25)	(0.29)	(1.54)
Foreign exchange gain/(loss)	0.05	0.10	0.15	(0.11)	0.64	0.53
Current income tax	(1.78)	–	(1.78)	(0.43)	–	(0.43)
Restoration and abandonment cash costs	(0.52)	0.52	–	(0.51)	0.51	–
Depletion, depreciation, amortization and accretion	–	(18.93)	(18.93)	–	(15.58)	(15.58)
Future income tax recovery/(expense)	–	5.53	5.53	–	(9.45)	(9.45)
Total per BOE	$ 43.67	$(31.36)	$ 12.31	$27.14	$(21.80)	$ 5.34

(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)	Six months ended June 30, 2008 Operating Cash Flow[1]	Non-Cash & Other Items	Total	Six months ended June 30, 2007 Operating Cash Flow[1]	Non-Cash & Other Items	Total
Production per day			94,681			84,244
Weighted average sales price[2]	$ 71.85	$ –	$ 71.85	$50.00	$ –	$ 50.00
Royalties	(13.46)	–	(13.46)	(9.43)	–	(9.43)
Commodity derivative instruments	(4.35)	(13.95)	(18.30)	0.45	(0.95)	(0.50)
Operating costs	(9.21)	0.04	(9.17)	(9.16)	0.06	(9.10)
General and administrative	(1.75)	(0.21)	(1.96)	(1.93)	(0.28)	(2.21)
Interest expense, net of other income	(1.10)	(0.01)	(1.11)	(1.25)	(0.03)	(1.28)
Foreign exchange (loss)/gain	–	(0.13)	(0.13)	(0.09)	0.32	0.23
Current income tax	(1.49)	–	(1.49)	(0.35)	–	(0.35)
Restoration and abandonment cash costs	(0.51)	0.51	–	(0.48)	0.48	–
Depletion, depreciation, amortization and accretion	–	(18.12)	(18.12)	–	(15.48)	(15.48)
Future income tax recovery/(expense)	–	4.97	4.97	–	(3.10)	(3.10)
Gain on sale of marketable securities[3]	–	0.48	0.48	–	0.92	0.92
Total per BOE	$ 39.98	$(26.42)	$ 13.56	$27.76	$(18.06)	$ 9.70

(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 six months ended June 30, 2008 and 2007.

(CDN$ millions, except per unit amounts)	Three months ended June 30, 2008			Three months ended June 30, 2007		
	Canada	U.S.	Total	Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	346,554	12,795	359,349	254,122	10,824	264,946
Crude oil (bbls/day)	25,652	9,834	35,486	24,563	9,615	34,178
Natural gas liquids (bbls/day)	4,810	–	4,810	4,143	–	4,143
Total Daily Sales (BOE/day)	88,221	11,967	100,188	71,059	11,419	82,478
Pricing[(1)]						
Natural gas (per Mcf)	$ 9.80	$ 11.80	$ 9.87	$ 7.03	$ 7.37	$ 7.04
Crude oil (per bbl)	112.41	118.27	114.04	59.59	67.94	61.93
Natural gas liquids (per bbl)	80.55	–	80.55	53.34	–	53.34
Capital Expenditures						
Development capital and office	$ 76.5	$ 13.5	$ 90.0	$ 49.1	$ 32.9	$ 82.0
Acquisitions of oil and gas properties	2.0	(0.2)	1.8	204.5	(0.5)	204.0
Dispositions of oil and gas properties	(0.1)	–	(0.1)	(5.5)	–	(5.5)
Revenues						
Oil and gas sales[(1)]	$ 614.8	$ 119.6	$ 734.4	$ 315.8	$ 66.7	$ 382.5
Royalties[(2)]	(112.4)	(25.6)	(138.0)	(58.9)	(13.3)	(72.2)
Financial contracts	(225.0)	–	(225.0)	18.0	–	18.0
Expenses						
Operating	$ 80.8	$ 5.2	$ 86.0	$ 70.6	$ 2.2	$ 72.8
General and administrative	16.0	1.3	17.3	14.9	1.8	16.7
Depletion, depreciation, amortization and accretion	149.6	22.9	172.5	89.5	27.4	116.9
Current income taxes (recovery)/expense	(5.3)	21.5	16.2	–	3.2	3.2

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

(CDN$ millions, except per unit amounts)	Six months ended June 30, 2008			Six months ended June 30, 2007		
	Canada	U.S.	Total	Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	321,177	12,382	333,559	260,051	10,249	270,300
Crude oil (bbls/day)	24,687	9,689	34,376	24,946	9,923	34,869
Natural gas liquids (bbls/day)	4,712	–	4,712	4,325	–	4,325
Total Daily Sales (BOE/day)	82,929	11,752	94,681	72,613	11,631	84,244
Pricing[(1)]						
Natural gas (per Mcf)	$ 8.72	$ 10.42	$ 8.79	$ 7.12	$ 7.33	$ 7.13
Crude oil (per bbl)	98.89	104.50	100.47	57.24	65.41	59.56
Natural gas liquids (per bbl)	75.29	–	75.29	48.55	–	48.55

(CDN$ millions, except per unit amounts)	Six months ended June 30, 2008 Canada	U.S.	Total	Six months ended June 30, 2007 Canada	U.S.	Total
Capital Expenditures						
Development capital and office	$ 184.8	$ 33.1	$ 217.9	$ 122.6	$ 70.8	$ 193.4
Acquisitions of oil and gas properties	9.4	(0.1)	9.3	206.6	60.8	267.4
Dispositions of oil and gas properties	(2.2)	–	(2.2)	(5.5)	–	(5.5)
Revenues						
Oil and gas sales(1)	$1,030.3	$ 207.8	$1,238.1	$ 631.4	$131.1	$ 762.5
Royalties(2)	(187.4)	(44.5)	(231.9)	(117.7)	(26.1)	(143.8)
Financial contracts	(315.4)	–	(315.4)	(7.6)	–	(7.6)
Expenses						
Operating	$ 149.4	$ 8.6	$ 158.0	$ 134.5	$ 4.3	$ 138.8
General and administrative	31.1	2.7	33.8	29.7	4.1	33.8
Depletion, depreciation, amortization and accretion	268.0	44.3	312.3	181.0	55.0	236.0
Current income taxes (recovery)/expense	(7.9)	33.7	25.8	–	5.3	5.3

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

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	Diluted
2008				
Second Quarter	$ 734.4	$112.2	$0.68	$0.68
First quarter	503.7	121.4	0.82	0.82
Total	$1,238.1	$233.6	$1.50	$1.50
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

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.

Following the completion of the Focus acquisition, Enerplus 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 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.

Cash Flow from Operating Activities, Cash Distributions and Payout Ratio

Cash flow from operating activities and cash distributions are reported on the Consolidated Statements of Cash Flows. During the second quarter of 2008 cash distributions of $202.3 million were funded entirely through cash flow of $364.5 million. For the six months ended June 30, 2008 our cash distributions were $394.7 million and were funded entirely through cash flow of $620.7 million.

Our payout ratio, which is calculated as cash distributions divided by cash flow, was 56% and 64% for the three and six months ended June 30, 2008 respectively, compared to 68% and 74% for the same periods in 2007. See "Non-GAAP Measures" in this MD&A.

In aggregate, our 2008 second quarter cash distributions of $202.3 million combined with our development capital and office expenditures of $90.0 million totaled $292.3 million, or approximately 80% of our cash flow of $364.5 million. For the six month ended June 30, 2008 our cash distributions of $394.7 million combined with our development capital and office expenditures of $217.9 million totaled $612.6 million, or approximately 99% of our cash flow of $620.7 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 June 30, 2008, our cash distributions exceeded our net income by $90.1 million (2007 – $122.5 million), however net income includes $290.6 million of non-cash items (2007 – $167.4 million). For the six months ended June 30, 2008 our cash distributions exceeded our net income by $161.1 million (2007 – $172.3 million) which included $472.3 million of non-cash items (2007 – $296.5 million). Non-cash items such as changes in the fair value of our derivative instruments and future income taxes do not reduce or increase our 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 June 30, 2008	Six months ended June 30, 2008	Year ended December 31, 2007	Year ended December 31, 2006
Cash flow from operating activities	$364.5	$ 620.7	$ 868.5	$863.7
Cash distributions	202.3	394.7	646.8	614.3
Excess of cash flow over cash distributions	$162.2	$ 226.0	$ 221.7	$249.4
Net income	$112.2	$ 233.6	$ 339.7	$544.8
Shortfall of net income over cash distributions	(90.1)	(161.1)	(307.1)	(69.5)
Cash distributions per weighted average trust unit	$ 1.23	$ 2.53	$ 5.07	$ 5.05
Payout ratio[1]	56%	64%	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 June 30, 2008 was $1,028.3 million which is comprised of $792.2 million of bank indebtedness and $236.1 million of senior unsecured notes. The increase in long-term debt compared to December 31, 2007 of $301.6 million is mainly due to the $330.9 million of debt that was assumed on the Focus acquisition. We reduced long term debt by $68.7 million during the second quarter of 2008 with excess cash flow.

Our working capital deficiency, excluding cash, at June 30, 2008 increased $106.9 million to $310.3 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 $63.5 million compared to December 31, 2007. This decrease is primarily due to higher accounts receivable attributable to higher commodity prices and production levels.

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

Financial Leverage and Coverage	June 30, 2008	December 31, 2007
Long-term debt to trailing cash flow	0.9x	0.8x
Cash flow to interest expense	20.6x	25.8x
Long-term debt to long-term debt plus equity	21%	22%

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

After applying the proceeds of approximately $500 million from the sale of our Joslyn interest to our debt, we anticipate our debt to cash flow ratio will be 0.4 times.

At June 30, 2008 Enerplus had a $1.4 billion unsecured covenant based three-year term bank facility ending 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 three-year term. This bank debt 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 June 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.

We continue to have adequate liquidity to fund planned development capital spending during 2008 through a combination of cash flow retained by the business and debt, if needed.

Trust Unit Information

We had 164,709,000 trust units outstanding at June 30, 2008. This includes the 30,150,000 units issued on February 13, 2008 to acquire Focus and 7,885,000 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 remaining 7,885,000 exchangeable limited partnership units are convertible at the option of the holder into 0.425 of an Enerplus trust unit (3,351,000 trust units). This compares to 129,205,000 trust units at June 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 six months ended June 30, 2008 was 155,984,000 (2007 – 125,849,000). At July 31, 2008 we had 164,807,000 trust units outstanding including the equivalent limited partnership units.

During the three months ended June 30, 2008, 683,000 trust units (2007 – 416,000) 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 $28.8 million (2007 – $18.6 million) of additional equity to the Fund. For the six months ended June 30, 2008 $40.7 million of additional equity (2007 – $31.7 million) and 1,000,000 trust units (2007 – 699,000) were issued pursuant to the DRIP and the trust unit options and 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. 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 still cannot determine when or even if Bill 1672 will be enacted as presented.

In July 2008, Enerplus estimated its non-resident ownership to be approximately 64%.

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. In particular, we are currently reviewing the Government of Canada’s “Turning the Corner” plan. Given Enerplus’ interest in various oil sands development areas we will be closely monitoring the development of these proposed federal regulations.

We will be working with government at all levels where we have operations to assist in the development of regulatory design in an effort to strike a productive balance between environmental responsibility and continued positive economic impact. At this stage, without further clarity and specific details from the Government of Canada, it is very difficult to forecast 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. We continue to assess the impact of adopting IFRS and implementing plans for transition.

Internal Controls and Procedures

There were no changes in our internal control over financial reporting during the quarter ended June 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; 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; 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 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 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.

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.

CONSOLIDATED BALANCE SHEETS

(CDN$ thousands) (Unaudited)	June 30, 2008	December 31, 2007
Assets		
Current assets		
Cash	$ 723	$ 1,702
Accounts receivable	242,999	145,602
Deferred financial assets (Note 9)	1,122	10,157
Future income taxes	86,140	10,807
Other current	7,336	6,373
	338,320	174,641
Property, plant and equipment (Note 2)	5,570,402	3,872,818
Goodwill (Note 4)	603,255	195,112
Other assets (Note 9)	50,216	60,559
	$ 6,562,193	$ 4,303,130
Liabilities		
Current liabilities		
Accounts payable	$ 289,576	$ 269,375
Distributions payable to unitholders	69,180	54,522
Deferred financial credits (Note 9)	289,100	52,488
	647,856	376,385
Long-term debt (Note 5)	1,028,301	726,677
Deferred financial credits (Note 9)	85,621	90,090
Future income taxes	697,065	304,259
Asset retirement obligations (Note 3)	203,411	165,719
	2,014,398	1,286,745
Equity		
Unitholders' capital (Note 8)	5,438,100	4,032,680
Accumulated deficit	(1,445,033)	(1,283,953)
Accumulated other comprehensive income	(93,128)	(108,727)
	(1,538,161)	(1,392,680)
	3,899,939	2,640,000
	$ 6,562,193	$ 4,303,130

CONSOLIDATED STATEMENTS OF ACCUMULATED DEFICIT

	Three months ended June 30,		Six months ended June 30,	
(CDN$ thousands) (Unaudited)	**2008**	2007	**2008**	2007
Accumulated income, beginning of period	**$ 2,408,321**	$ 2,055,109	**$ 2,286,927**	$ 1,952,960
Adjustment for adoption of financial instruments standards	**–**	–	**–**	(5,724)
Revised accumulated income, beginning of period	**2,408,321**	2,055,109	**2,286,927**	1,947,236
Net income	**112,230**	40,084	**233,624**	147,957
Accumulated income, end of period	**$ 2,520,551**	$ 2,095,193	**$ 2,520,551**	$ 2,095,193
Accumulated cash distributions, beginning of period	**$ (3,763,238)**	$(3,081,716)	**$ (3,570,880)**	$(2,924,045)
Cash distributions	**(202,346)**	(162,607)	**(394,704)**	(320,278)
Accumulated cash distributions, end of period	**$ (3,965,584)**	$(3,244,323)	**$ (3,965,584)**	$(3,244,323)
Accumulated deficit, end of period	**$ (1,445,033)**	$(1,149,130)	**$ (1,445,033)**	$(1,149,130)

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

	Three months ended June 30,		Six months ended June 30,	
(CDN$ thousands) (Unaudited)	**2008**	2007	**2008**	2007
Balance, beginning of period	**$ (87,505)**	$(15,525)	**$ (108,727)**	$ (8,979)
Transition adjustments on adoption:				
Cash flow hedges	**–**	–	**–**	660
Available for sale marketable securities	**–**	–	**–**	14,252
Other comprehensive (loss)/income	**(5,623)**	(49,853)	**15,599**	(71,311)
Balance, end of period	**$ (93,128)**	$(65,378)	**$ (93,128)**	$(65,378)

CONSOLIDATED STATEMENTS OF INCOME

(CDN$ thousands, except per trust unit amounts) (Unaudited)	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Revenues				
Oil and gas sales	$ 741,470	$387,926	$1,251,539	$ 773,797
Royalties	(138,040)	(72,214)	(231,876)	(143,762)
Commodity derivative instruments (Note 9)	(225,015)	17,954	(315,394)	(7,652)
Other income	411	272	15,527	14,432
	378,826	333,938	719,796	636,815
Expenses				
Operating	85,974	72,756	157,990	138,786
General and administrative	17,327	16,660	33,764	33,770
Transportation	7,127	5,453	13,444	11,317
Interest (Note 6)	19,313	11,847	26,301	19,962
Foreign exchange (Note 7)	(1,408)	(3,956)	2,276	(3,474)
Depletion, depreciation, amortization and accretion	172,496	116,909	312,290	236,000
	300,829	219,669	546,065	436,361
Income before taxes	77,997	114,269	173,731	200,454
Current taxes	16,211	3,227	25,752	5,291
Future income tax (recovery)/expense	(50,444)	70,958	(85,645)	47,206
Net Income	$ 112,230	$ 40,084	$ 233,624	$ 147,957
Net income per trust unit				
Basic	$ 0.68	$ 0.31	$ 1.50	$ 1.18
Diluted	$ 0.68	$ 0.31	$ 1.50	$ 1.18
Weighted average number of trust units outstanding (thousands)[1]				
Basic	164,483	128,361	155,984	125,849
Diluted	164,633	128,419	156,102	125,904

[1] Includes the exchangeable limited partnership units.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(CDN$ thousands) (Unaudited)	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Net income	$112,230	$ 40,084	$223,624	$147,957
Other comprehensive income/(loss), net of tax:				
Unrealized gain/(loss) on marketable securities	–	2,502	2,578	(654)
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	–	(176)	74	(380)
Change in cumulative translation adjustment	(5,623)	(52,179)	19,105	(58,623)
Other comprehensive income/(loss)	(5,623)	(49,853)	15,599	(71,311)
Comprehensive income	$106,607	$ (9,769)	$239,223	$ 76,646

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended June 30,		Six months ended June 30,	
(CDN$ thousands) (Unaudited)	**2008**	2007	**2008**	2007
Operating Activities				
Net income	**$ 112,230**	$ 40,084	**$ 233,624**	$ 147,957
Non-cash items add/(deduct):				
Depletion, depreciation, amortization and accretion	**172,496**	116,909	**312,290**	236,000
Change in fair value of derivative instruments (Note 9)	**168,787**	(1,394)	**235,259**	33,453
Unit based compensation (Note 8)	**2,094**	2,107	**3,580**	4,218
Foreign exchange on translation of senior notes (Note 7)	**(2,158)**	(20,808)	**7,075**	(23,690)
Future income tax	**(50,444)**	70,958	**(85,645)**	47,206
Amortization of senior notes premium	**(157)**	(159)	**(310)**	(328)
Reclassification adjustments from AOCI to net income	**–**	(176)	**92**	(380)
Gain on sale of marketable securities	**–**	–	**(8,263)**	(14,055)
Asset retirement obligations settled (Note 3)	**(4,747)**	(3,803)	**(8,767)**	(7,117)
	398,101	203,718	**688,935**	423,264
(Increase)/Decrease in non-cash operating working capital	**(33,644)**	33,764	**(68,262)**	7,399
Cash flow from operating activities	**364,457**	237,482	**620,673**	430,663
Financing Activities				
Issue of trust units, net of issue costs (Note 8)	**28,811**	218,204	**40,696**	231,224
Cash distributions to unitholders	**(202,346)**	(162,607)	**(394,704)**	(320,278)
(Decrease)/Increase in bank credit facilities	**(68,656)**	(35,992)	**(36,054)**	64,350
Decrease in non-cash financing working capital	**241**	180	**14,658**	2,549
Cash flow from financing activities	**(241,950)**	19,785	**(375,404)**	(22,155)
Investing Activities				
Capital expenditures	**(89,961)**	(82,000)	**(217,884)**	(193,354)
Property acquisitions	**(1,740)**	(149,266)	**(9,289)**	(212,644)
Property dispositions	**86**	(1,107)	**2,208**	(1,152)
Proceeds on sale of marketable securities	**–**	–	**18,320**	16,467
Increase in non-cash investing working capital	**(30,218)**	(20,627)	**(40,636)**	(14,497)
Cash flow from investing activities	**(121,833)**	(253,000)	**(247,281)**	(405,180)
Effect of exchange rate changes on cash	**(1,404)**	(2,311)	**1,033**	(1,402)
Change in cash	**(730)**	1,956	**(979)**	1,926
Cash, beginning of period	**1,453**	94	**1,702**	124
Cash, end of period	**$ 723**	$ 2,050	**$ 723**	$ 2,050
Supplementary Cash Flow Information				
Cash income taxes paid	**$ 24,756**	$ 4,005	**$ 33,758**	$ 7,246
Cash interest paid	**$ 17,980**	$ 14,644	**$ 26,298**	$ 20,730

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)	June 30, 2008	December 31, 2007
Property, plant and equipment	$ 8,440,623	$ 6,429,241
Accumulated depletion, depreciation and accretion	(2,870,221)	(2,556,423)
Net property, plant and equipment	$ 5,570,402	$ 3,872,818

Capitalized development general and administrative ("G&A") expense of $10,812,000 (2007 – $8,158,000) is included in PP&E for the six months ended June 30, 2008. Excluded from PP&E for the depletion and depreciation calculation is $351,124,000 (2007 – $302,459,000) related to the Joslyn development project and the Kirby oil sands project, both of which have not yet commenced commercial production.

3. ASSET RETIREMENT OBLIGATIONS

Following is a reconciliation of the asset retirement obligations:

($ thousands)	Six months ended June 30, 2008	Year ended December 31, 2007
Asset retirement obligations, beginning of period	$165,719	$123,619
Corporate acquisition	36,784	–
Changes in estimates	1,475	46,000
Property acquisition and development activity	2,667	6,441
Dispositions	(110)	(756)
Asset retirement obligations settled	(8,767)	(16,280)
Accretion expense	5,643	6,695
Asset retirement obligations, end of period	$203,411	$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 approximately $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 estimated 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)	June 30, 2008	December 31, 2007
Bank credit facilities (a)	$ 792,205	$497,347
Senior notes (b)		
US$175 million (issued June 19, 2002)	181,092	175,973
US$54 million (issued October 1, 2003)	55,004	53,357
Total long-term debt	$1,028,301	$726,677

(a) Unsecured Bank Credit Facility

Enerplus currently has a $1.4 billion unsecured covenant based three-year term facility. The facility is extendible each year with a bullet payment required at the end of the three year 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 six months ended June 30, 2008 was 4.0% (June 30, 2007 – 4.9%).

(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 June 30, 2008 the amortized cost of the US$175,000,000 senior notes was US$177,785,000.

6. INTEREST EXPENSE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2008**	2007	**2008**	2007
Realized				
Interest on long-term debt	**$12,918**	$ 9,731	**$26,263**	$19,481
Unrealized				
Loss/(gain) on cross currency interest rate swap	**7,219**	4,193	**(1,125)**	2,909
(Gain)/loss on interest rate swaps	**(667)**	(1,918)	**1,473**	(2,100)
Amortization of the premium on senior unsecured notes	**(157)**	(159)	**(310)**	(328)
Interest expense	**$19,313**	$11,847	**$26,301**	$19,962

7. FOREIGN EXCHANGE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2008**	2007	**2008**	2007
Realized				
Foreign exchange (gain)/loss	**$ (550)**	$ 854	**$ 18**	$ 1,442
Unrealized				
Foreign exchange (gain)/loss on translation of U.S. dollar denominated senior notes	**(2,158)**	(20,808)	**7,075**	(23,690)
Foreign exchange (gain)/loss on cross currency interest rate swap	**(320)**	15,998	**(4,491)**	18,774
Foreign exchange loss/(gain) on foreign exchange swaps	**1,620**	–	**(326)**	–
Foreign exchange (gain)/loss	**$(1,408)**	$ (3,956)	**$ 2,276**	$ (3,474)

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)	**Six months ended June 30, 2008**	Year ended December 31, 2007
Trust units	**$5,286,045**	$4,020,228
Exchangeable limited partnership units	**134,106**	–
Contributed surplus	**17,949**	12,452
Balance, end of period	**$5,438,100**	$4,032,680

(a) Trust Units

Authorized: Unlimited number of trust units

	Six months ended June 30, 2008		Year ended December 31, 2007	
(thousands)	Units	Amount	Units	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	174	5,755	205	6,758
Cancelled trust units	(116)	(3,794)	–	–
Exchangeable limited partnership units exchanged	511	20,445	–	–
Trust unit rights incentive plan (non-cash) – exercised	–	1,877	–	2,288
DRIP*, net of redemptions	826	34,941	1,102	50,053
Issued for acquisition of corporate and property interests (non-cash)	30,150	1,206,593	1,105	54,750
	161,358	$5,286,045	129,813	$4,020,228
Equivalent exchangeable partnership units	3,351	134,106	–	–
Balance, end of period	164,709	$5,420,151	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 the 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 second quarter of 2008, 1,202,000 exchangeable limited partnership units were converted into 511,000 trust units. As at June 30, 2008, the 7,885,000 outstanding exchangeable limited partnership units represent the equivalent of 3,351,000 trust units.

	Six months ended June 30, 2008		Year ended December 31, 2007	
(thousands)	Units	Amount	Units	Amount
Issued:				
Assumed on February 13, 2008	9,087	$154,551	–	$ –
Exchanged for trust units	(1,202)	(20,445)	–	–
Balance, end of period	7,885	$134,106	–	$ –

(c) Contributed Surplus

Contributed surplus ($ thousands)	Six months ended June 30, 2008	Year ended December 31, 2007
Balance, beginning of period	$12,452	$ 6,305
Trust unit rights incentive plan (non-cash) – exercised	(1,877)	(2,288)
Trust unit rights incentive plan (non-cash) – expensed	3,580	8,435
Cancelled trust units	3,794	–
Balance, end of period	$17,949	$12,452

(d) Trust Unit Rights Incentive Plan

As at June 30, 2008 a total of 4,324,000 rights were issued pursuant to the Trust Unit Rights Incentive Plan ("Rights Incentive Plan") with an average exercise price of $45.73 and were outstanding. This represents 2.6% of the total trust units outstanding of which 1,795,000 rights, with an average exercise price of $45.70, 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 and second quarter of 2008 reduced the exercise price of the outstanding rights by $0.43 per trust unit effective July 2008 and $0.41 per trust unit effective October 2008.

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

	Six months ended June 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	1,348	42.34	816	48.71
Exercised	(174)	33.01	(205)	32.90
Cancelled	(254)	47.04	(286)	50.74
End of period	4,324	$45.73	3,404	$47.59
Rights exercisable at end of period	1,795	$45.70	1,635	$44.84

(1) Exercise price reflects grant prices less reduction in strike 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 related to rights issued for the three and six months ended June 30, 2008 were $2,094,000 ($0.01 per unit) and $3,580,000 ($0.02 per unit) respectively. Non-cash compensation costs for the three and six months ended June 30, 2007 were $2,107,000 ($0.02 per unit) and $4,218,000 ($0.03 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 Plan.

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

	Six months ended June 30,	
(thousands)	2008	2007
Weighted average trust units	153,138	125,849
Weighted average exchangeable limited partnership units[1]	2,846	–
Basic weighted average units outstanding	155,984	125,849
Dilutive impact of rights	118	55
Diluted weighted average units outstanding	156,102	125,904

(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 is variable to individuals and they vest at the end of three years. Upon vesting, the plan participant receives a cash payment based on the fair value of the underlying trust units plus notional accrued distributions. The value determined upon vesting of the PTU plans is dependent upon the performance of the Fund compared to its peers over the three year period. The level of performance within the peer group then determines a performance multiplier.

For the three months and six months ended June 30, 2008 the Fund recorded cash compensation costs of $1,217,000 (2007 – $570,000) and $2,300,000 (2007 – $915,000), respectively, under the plan which are included in general and administrative expenses.

At June 30, 2008 there were 435,000 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 June 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 June 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 June 30, 2008 the Fund reported investments in marketable securities of private companies at cost of $49,966,000 (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 June 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 June 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$177,785,000 and are translated to Canadian dollars at the period end exchange rate. At June 30, 2008 the Canadian dollar amortized cost of the senior notes was approximately $181,092,000 and the fair value of these notes was $189,082,000.

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 June 30, 2008 the Canadian dollar amortized cost of the senior notes was approximately $55,004,000 and the fair value of these notes was approximately $54,830,000.

(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 June 30, 2008 a current deferred financial asset of $1,122,000, a current deferred financial credit of $289,100,000 and a long-term deferred financial credit of $85,621,000 are recorded on the consolidated balance sheet.

The deferred financial credit relating to crude oil instruments of $199,211,000 at June 30, 2008 consists of the fair value of the financial instruments, representing a loss position of $186,054,000 plus the related deferred premiums of $13,157,000. The deferred financial credit relating to natural gas instruments of $89,889,000 at June 30, 2008 consists of the fair value of the financial instruments of $84,619,000 plus the related deferred premiums of $5,270,000.

The following table summarizes the fair value as at June 30, 2008 and change in fair value for the period ended June 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.

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swaps	Foreign Exchange Swaps	Electricity Swaps	Commodity Derivative Instruments Oil	Commodity Derivative Instruments Gas	Total
Deferred financial assets/(credits), at December 31, 2007	$ (226)	$(89,439)	$ (425)	$ 450	$ (56,783)[1]	$ 8,083[2]	$(138,340)
Change in fair value asset/(credits)	(1,473)[3]	5,616[4]	326[5]	672[6]	(142,428)[7]	(97,972)[7]	(235,259)
Deferred financial assets/(credits), end of period	$(1,699)	$(83,823)	$ (99)	$1,122	$(199,211)	$(89,889)	$(373,599)
Balance sheet classification:							
Current asset/(liability)	$ –	$ –	$ –	$1,122	$(199,211)	$(89,889)	$(287,978)
Non-current asset/ (liability)	$(1,699)	$(83,823)	$ (99)	$ –	$ –	$ –	$ (85,621)

(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 $4,491) and interest expense (gain of $1,125).
(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 June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Loss/(gain) due to change in fair value	$160,955	$(19,052)	$240,400	$14,430
Net realized cash losses/(gain)	64,060	1,098	74,994	(6,778)
Commodity derivative instruments loss/(gain)	$225,015	$(17,954)	$315,394	$ 7,652

(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 July 25, 2008 are summarized below:

Crude Oil:

	Daily	WTI US$/bbl			
	Volumes bbls/day	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term					
July 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(3)	400	–	–	–	$ 78.53
Swap	1,500	–	–	–	$ 92.00
Swap(3)	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(1)	500	–	$ 92.00	$79.00	–
Swap	500	–	–	–	$100.05
Put(1)	1,400	–	$122.00	–	–
Put(2)	500	–	$120.00	–	–

(1) Financial contracts entered into during the second quarter of 2008.
(2) Financial contracts entered into subsequent to June 30, 2008.
(3) Acquired through the acquisition of Focus.

Natural Gas:

	Daily Volumes MMcf/day	AECO CDN$/Mcf			
		Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term					
July 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(3)	14.2	–	–	–	$ 6.70
Swap(3)	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	–	–
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(1)	4.7	$12.45	$ 8.97	$ 7.39	–
Put Spread	4.7	–	$ 8.97	$ 7.39	–
Put Spread(1)	4.7	–	$ 8.97	$ 7.39	–
Swap	2.8	–	–	–	$ 9.42
Swap	2.8	–	–	–	$ 9.28
Swap	2.8	–	–	–	$ 9.34
Put(1)	4.7	–	$11.34	–	–
Put(2)	4.7	–	$11.61	–	–
Put(2)	4.7	–	$ 9.50	–	–
April 1, 2009 – October 31, 2009					
Swap	3.8	–	–	–	$ 7.86
Put Spread(1)	2.8	–	$ 9.23	$ 7.65	–
Put Spread(1)	2.8	–	$ 9.50	$ 7.91	–
Put Spread(1)	5.6	–	$ 9.60	$ 7.91	–
2008 – 2010					
Physical (escalated pricing)	2.0	–	–	–	$ 2.59

(1) Financial contracts entered into during the second quarter of 2008.
(2) Financial contracts entered into subsequent to June 30, 2008.
(3) Acquired through the acquisition of Focus.

The following sensitivities show the impact to after-tax net income for the three months ended June 30, 2008 of the respective changes in forward crude oil and natural gas prices as at June 30, 2008 on the Fund's commodity derivative contracts, with all other variables held constant:

	Increase/(decrease) to after-tax net income	
($ thousands)	20% decrease in forward prices	20% increase in forward prices
Crude oil derivative contracts	$70,934	$(67,469)
Natural gas derivative contracts	$39,235	$(42,823)

Electricity:

The Fund is subject to electricity price fluctuations and it manages this risk by entering into forward fixed rate electricity derivative contracts on a portion of its electricity requirements. The Fund's outstanding electricity derivative contracts as at July 25, 2008 are summarized below:

Term	Volumes MWh	Price CDN$/MWh
July 1, 2008 – September 30, 2008	4.0	$63.00
July 1, 2008 – December 31, 2009	4.0	$74.50

The Fund did not enter into any new electricity contracts in the second 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 CDN/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 for the three months ended June 30, 2008 of the respective changes in the period end and applicable forward foreign exchange rates as at June 30, 2008, with all other variables held constant:

	Increase/(decrease) to after-tax net income	
($ thousands)	10% decrease in $CDN relative to $US	10% increase in $CDN relative to $US
Translation of senior unsecured notes	$(7,029)	$7,029

($ thousands)	Increase/(decrease) to after-tax net income 10% decrease in $CDN relative to $US	 10% increase in $CDN relative to $US
Foreign exchange swaps	$ 7	$ (7)
Cross currency interest rate swap[1]	$6,732	$(6,732)

(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 $100,000,000 of notional debt at rates varying from 3.70% to 4.61% before banking fees that are expected to range between 0.55% and 1.10%. These interest rate swaps mature between June 2011 and April 2013.

If interest rates change by 1%, either lower or higher, on our variable rate debt outstanding at June 30, 2008 with all other variables held constant, the Fund's after-tax net income for a quarter would change by $1,063,000.

The following sensitivities show the impact to after-tax net income for the three months ended June 30, 2008 of the respective changes in the applicable forward interest rates as at June 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	$ (239)	$ 239
Cross currency interest rate swap[1]	$1,687	$(1,687)

(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 June 30, 2008 approximately 80% 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 June 30, 2008 approximately $7,700,000 or 3% 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 June 30, 2008 is $3,800,000, which includes a $1,000,000 provision made during the quarter relating to receivables from a Canadian subsidiary of SemGroup LP. 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 June 30, 2008 the debt to cash flow ratio was 0.9x including the 12 months of trailing cash flow from Focus (June 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. After applying the proceeds from the sale of our Joslyn interest our debt to trailing cash flow ratio will be 0.4x. Enerplus' five-year history of debt to cash flow is illustrated below:

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

At June 30, 2008 Enerplus had additional borrowing capacity of $607,795,000 under its $1.4 billion bank credit facility. The Fund also has 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 $580 million developing existing assets. A portion of this capital spending is considered discretionary. There are limitations to changing the capital spending plans during a year. 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 the additional funds are available to reduce debt, spend on capital development 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. Enerplus has maintained the current distribution level of $0.42/unit for 34 consecutive months. A stable or growing distribution pattern typically helps support the market price of the trust units. 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 is 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. In addition, the equity capital markets have indicated their continued support. Nonetheless, the capital markets can change rapidly with very little notice.

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 subsequent to the quarter, the proceeds of which will be 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 June 30, 2008:

		Payments Due by Period					Total Committed
($ thousands)	Total	2008	2009	2010	2011	2012	after 2013
Accounts Payable	$ 289,576(1)	$289,576	$ –	$ –	$ –	$ –	$ –
Distributions payable to unitholders	69,180(2)	69,180	–	–	–	–	–
Bank credit facility	792,205	–	–	792,205	–	–	–
Senior unsecured notes	323,408(3)	–	–	53,666	64,682	64,682	140,378
Total commitments	$1,474,369	$358,756	$ –	$845,871	$64,682	$64,682	$140,378

(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. Historically, the bank credit facilities have been renewed annually, refreshing the associated three year term period. Similarly, it is expected that the senior unsecured notes will be replaced with replacement notes or bank debt as they become due. 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. SUBSEQUENT EVENT

On July 31, 2008, subsequent to the quarter, Enerplus disposed of its Joslyn interest for net proceeds of approximately $500 million.

BOARD OF DIRECTORS

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

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

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

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

David P. O'Brien[(3)]
Corporate Director
Calgary, Alberta

Glen D. Roane[(5)(10)]
Corporate Director
Canmore, Alberta

W. C. (Mike) Seth[(3)(8)]
President
Seth Consultants Ltd.
Okotoks, Alberta

Donald T. West[(7)(11)]
Corporate Director
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

Gordon J. Kerr
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 Daniels
Vice President, Oil Sands

Rodney D. Gray
Vice President, Finance

Larry P. Hammond
Vice President, Operations

Dana W. Johnson
President, U.S. Operations

Lyonel G. Kawa
Vice President, Information Services

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

Wayne G. Ford
Controller, Operations

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, CO

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
Fax: 720.279.5550

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

THE ENERGY OF

enerPLUS

www.enerplus.com

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

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

ERF LISTED NYSE

ERF.UN LISTED TSX