THE ENERGY OF
enerPLUS

FIRST QUARTER REPORT

Three months ended March 30, 2008

FINANCIAL & OPERATING HIGHLIGHTS

Selected Financial Results

For the three months ended March 31,	2008	2007
Financial (000's)		
Cash Flow from Operating Activities	$ 256,216	$ 193,181
Cash Distributions to Unitholders[1]	192,358	157,671
Cash Withheld for Acquisitions and Capital Expenditures	63,858	35,510
Net Income	121,394	107,873
Debt Outstanding (net of cash)	1,097,821	716,860
Development Capital Spending	126,262	109,952
Acquisitions	1,765,069	63,423
Divestments	2,122	–
Actual Cash Distributions paid to Unitholders	$ 1.26	$ 1.26
Financial per Weighted Average Trust Units[2]		
Cash Flow from Operating Activities	$ 1.74	$ 1.57
Cash Distributions per Unit[1]	1.30	1.28
Cash Withheld for Acquisitions and Capital Expenditures	0.44	0.29
Net Income	0.82	0.88
Payout Ratio[3]	75%	82%
Selected Financial Results per BOE[4]		
Oil & Gas Sales[5]	$ 62.10	$ 49.08
Royalties	(11.57)	(9.24)
Commodity Derivative Instruments	(1.35)	1.01
Operating Costs	(8.96)	(8.55)
General and Administrative	(1.85)	(1.94)
Interest and Other Income and Foreign Exchange	(0.84)	(1.32)
Taxes	(1.18)	(0.26)
Restoration and Abandonment	(0.50)	(0.42)
Cash Flow from Operating Activities before changes in non-cash working capital	$ 35.85	$ 28.36
Weighted Average Number of Trust Units Outstanding Including Equivalent Exchangeable Partnership Units (thousands)	147,482	123,282
Debt/Trailing 12 Month Cash Flow Ratio[6]	1.0x	0.8x

Selected Operating Results

For the three months ended March 31,	2008	2007
Average Daily Production		
Natural gas (Mcf/day)	307,746	275,714
Crude oil (bbls/day)	33,256	35,567
NGLs (bbls/day)	4,603	4,509
Total (BOE/day)	89,150	86,028
% Natural gas	58%	53%
Average Selling Price[5]		
Natural gas (per Mcf)	$ 7.52	$ 7.21
Crude oil (per bbl)	86.02	57.26
NGLs (per bbl)	69.75	44.09
US$ exchange rate	1.00	0.85
Net Wells drilled	125	40
Success Rate	100%	98%

(1) Calculated based on distributions paid or payable. Cash distributions per unit may not correspond to the actual cash distributions to unitholders of $1.26 as a result of using the weighted average trust units outstanding for the period.
(2) Based on weighted average trust units outstanding for the period, including the exchangeable 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 March 31, 2008	TSX – ERF.un (CDN$)	NYSE – ERF (US$)
High	$44.75	$44.31
Low	$34.02	$32.59
Close	$44.65	$43.40

2008 Cash Distributions Per Trust Unit

Production Month	Payment Month	CDN$	US$
January	March	$0.42	$0.41
February	April	0.42	0.42
March	May	0.42	0.41*
First Quarter Total		**$1.26**	**$1.24**

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

PRESIDENT'S MESSAGE

The first quarter of 2008 was marked with a number of significant achievements for Enerplus the most important of which was the closing of our single largest acquisition in our history. The $1.7 billion acquisition of Focus Energy Trust was completed on February 13, 2008 and the integration of the Focus assets and our new staff is proceeding smoothly as evidenced by our production volumes and the successful execution of our capital development program through the quarter. The concentration and overlap of the Focus properties (approximately 85% of the total production volumes from Focus was derived from the Shackleton, Saskatchewan and Tommy Lakes, British Columbia properties) and our combined technical and execution expertise have been key elements in the integration. We are also pleased to have retained over 85% of the Focus staff to assist with the on-going management of our assets. Enerplus now has a production weighting of just over 60% natural gas and 40% crude oil and NGLs in its portfolio.

I am pleased to report that our operations are performing to expectations. Daily production volumes averaged 89,150 BOE/day reflecting the additional volumes from Focus since February 13, 2008. As mentioned in prior reports, production volumes have also been impacted by the fire at our Giltedge property however we are pleased to report that approximately 460 BOE/day of the 2,000 BOE/day originally shut-in is back on-line earlier than anticipated. We now expect full production volumes to be back on-line in early May. Our production volumes in March were approximately 100,000 BOE/day, being the first full month including Focus production and an all-time high for Enerplus.

Cash flow from operating activities was $256.2 million up 33% over the same period last year on the strength of increased commodity prices and production volumes. We continued to maintain our cash distributions per unit at $0.42 per month ($1.26 per unit for the quarter) and at a payout ratio of 75% versus 82% last year after adjustments for working capital. Based on existing commodity prices and current distribution levels, we would expect our payout ratio will decrease throughout the year. We continue to maintain a conservative use of debt as reflected by our debt to trailing cash flow ratio of 1.0x.

Commodity prices have risen significantly during and subsequent to the first quarter of 2008. From the lowest price set during the first quarter 2008 to the recent high set in April 2008, natural gas prices at AECO have increased almost 50%. West Texas Intermediate ("WTI") prices have risen close to 40% over this same period. In fact, spot WTI prices in April 2008 are up over 100% versus the average WTI price in first quarter 2007. And with the rising Canadian dollar, the Canadian dollar price of WTI is now on parity with the U.S. dollar price. The rise in energy prices can be traced in part to improved fundamentals with global demand holding steady in spite of the current slowdown in the U.S. economy. Global supply continues to be vulnerable to geopolitical crises, a challenged re-investment cycle, and a rise in nationalization and windfall taxes in many jurisdictions. The rise in the WTI price, and with it the natural gas price, can also be attributed to the fall in the U.S. dollar through this period and the purchase of commodities as a hedge against inflation.

Regardless of the reasons for the energy price increase, Enerplus has benefited from these increases and the acquisition of Focus has proven very timely as the long-term gas price has increased significantly. We have continued to utilize a disciplined methodology to protect against downside commodity price risk, given the size of our capital program, our drive to maintain distributions, and the need to maintain acquisition economics, transacting over a range of commodity prices and time. Accordingly, since we started hedging for 2008 production at the start of second quarter 2007, we have in place fixed price swaps and call sales covering a portion of our volume that are currently below the forward market for both crude oil and natural gas. While we have benefited significantly from the rise in commodity prices, we have also recorded losses as a result of the hedges we have in place. A complete description of our hedge positions and the impacts are disclosed in our MD&A and financial statements.

It has been our practice to maintain cash distributions at a level that we believe can be maintained for an extended period of time while ensuring that we retain a strong balance sheet to provide us with the financial flexibility to manage our business for the long-term. Should commodity prices continue to remain at current levels and our operations continue to perform to expectations, we could expect that virtually all of our cash distributions and capital development activities (including our oil sands spending) may be funded from cash flow. Given the current strength of our balance sheet and should we be successful in divesting of our interest in the Joslyn lease, we would be very well positioned to fully fund our oil sands growth plans and/or pursue additional acquisition opportunities and minimize future equity dilution and/or increase cash distributions to unitholders.

2008 Production and Development Activity

Play Type As at March 31, 2008	Production Volumes (BOE/day)	Capital Spending ($ millions)	Wells Drilled* Gross	 Net
Shallow Gas & CBM	20,627	22.4	149	92.0
Crude Oil Waterfloods	14,784	17.2	22	10.5
Deep Tight Gas	11,937	22.9	28	4.0
Bakken Oil	10,878	19.6	4	3.1
Other Conventional Oil & Gas	30,924	22.7	53	15.2
Total Conventional	**89,150**	**104.8**	**256**	**124.8**
Oil Sands				
Kirby	–	20.6	–	–
Joslyn	–	.7	–	–
Laricina	–	.2	–	–
Total Oil Sands	–	**21.5**	–	–
Total	**89,150**	**126.3**	**256**	**124.8**

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

Success Rate To Date: 100%

Our development capital program was one of the most active in our history with total spending of approximately $126 million and 256 gross wells drilled. Over 50% of our development capital was invested in oil properties however the majority of the wells drilled were in our shallow natural gas resource play which offers a significant number of low risk infill drilling locations. Our Canadian drilling program employed as many as 17 drilling rigs and 20 service rigs in our operations including those dedicated to our Kirby delineation program throughout the quarter. Our U.S. operations also had two drilling rigs and 6 – 7 service rigs in use through the quarter. While modest savings were realized on day rates for drilling rigs, labour, steel and service costs have not abated.

With the recent strengthening in natural gas prices and the additional working interests in the Shackleton property acquired from Focus, we have increased our activities in our shallow gas resource play. During the quarter, Enerplus drilled almost 150 shallow gas wells, the majority of which were in the Countess and Verger area taking the well density to 16 wells per section. At Shackleton, a total of 41 Milk River natural gas wells were drilled during the quarter (including Enerplus and Focus activity) and booster compression was installed in the Miry Bay area. In addition, a total of 24 existing wells were recompleted to add reserves and production from the Milk River interval as well.

At Tommy Lakes, the winter drilling program was completed with a total of 17 wells successfully drilled, completed and tied-in before spring break up with results in line with expectations. This was slightly more than originally planned by Focus.

Our crude oil development activities continue to benefit from the current strength in oil prices. Although the number of wells drilled is significantly less than in the shallow natural gas arena, the cost and productivity per well is considerably higher. Our conventional oil activities were focused at Routledge and Shorncliffe in Southeast Saskatchewan and our waterfloods at Pembina, Alberta and Virden, Manitoba.

Development activity in our Bakken resource play kept two drilling rigs active for most of the quarter drilling four additional third wells per section. We temporarily slowed our refrac program to concentrate on higher return optimization activities and expect to resume the refrac program in June. Through our current activities in the U.S., we expect to maintain production volumes in the range of 11,000 BOE/day throughout 2008 with targeted spending of $55 to $65 million. We continue to advance our development plans beyond 2008 and have identified opportunities which will help to maintain production in the coming years. We also continue to pursue growth opportunities in the U.S. which are outside of our existing areas.

The high drilling and construction activity experienced during the quarter did contribute to a slight increase in our recordable and lost time injury frequency rates for both employees and contractors. We remain committed to continuous improvement in safety performance by supporting a culture in which all employees and contractors embrace safety in their day-to-day activities.

Update on Kirby Oil Sands Project

Development plans at our Kirby oil sands project continued throughout the first quarter with the execution of our winter delineation program. We drilled 55 core holes and 3 water source/disposal wells on the lease. Our preliminary review of the core hole samples is encouraging. We expect to use this new information in support of the initial development on this lease, a 10,000 bbl/day steam assisted gravity drainage ("SAGD") project, and will provide updated resources estimates for the lease once we have fully evaluated the results of this program. We continue to expect to file our regulatory application for the 10,000 bbl/day project in late fall of this year and will provide new capital estimates associated with the project as part of the application.

We are pleased to report that we have been successful in attracting experienced and talented personnel to our oil sands resource team over the past quarter and now have over 20 people dedicated exclusively to the Kirby oil sands project. Combined, we have over 130 years of oil sands experience and over 350 years of industry experience within the team including direct experience from most of the active SAGD projects in western Canada.

Strategic Review of Joslyn Lease

On March 25, 2008, we announced that we were commencing a review of strategic options regarding our 15% working interest in the Joslyn oil sands lease ("Joslyn"). Joslyn is located in the Athabasca oil sands fairway in northeastern Alberta and consists of both mining and SAGD development projects. Our oil sands portfolio is comprised of three principal investments: a 100% working interest in the operated Kirby SAGD project; a 15% non-operated working interest in the Joslyn mining and SAGD project; and a 12% equity investment and minor joint venture participation with Laricina Energy Ltd., ("Laricina") a private oil sands company pursuing SAGD projects in Alberta.

A strategic review of our portfolio of oil sands and conventional projects has resulted in the decision to consider options to rebalance our portfolio. Enerplus' low risk, distribution-oriented business model necessitates a portfolio of assets that provide near-term cash flow, future growth potential and an appropriate balance of commodities. Managing the future capital requirements of the portfolio while maintaining financial flexibility is critical to the long-term success of Enerplus. While we believe that both Joslyn and Kirby provide attractive long-term potential, the operated nature of the Kirby project provides enhanced control over the timing and nature of our capital spending profile. In addition, there are more SAGD opportunities within Canada for future growth and SAGD is better suited to our technical competencies and business model.

Should the strategic review result in a decision to sell all or a portion of Joslyn, sale proceeds would initially be used to reduce our current bank debt.

Greenhouse Gas Emissions Regulations

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 and will continue to evolve our strategies and responses to the plan. Draft regulations under the plan are expected to be published in the latter half of this year for public comment. Under the proposed plan, the oil and gas industry will be required to reduce its emissions intensity from 2006 levels by 18% by 2010 and 2% every following year. The proposed federal regulations also require oil sands upgraders and in-situ projects to meet certain carbon capture and storage targets by 2018. Given Enerplus' interest in various oil sands development areas (Kirby, Joslyn and Laricina), we will be closely monitoring the development of the proposed federal regulations.

In January, 2008, the Government of Alberta released its new climate change strategy. The Alberta strategy focuses on the three areas of carbon capture and storage, conserving and using energy more efficiently and "greening" energy production. The provincial government will be providing updates as to its specific plans for implementation of various portions of its strategy. Certain climate change regulations came in to effect in Alberta on July 1, 2007 which set an emissions level of 100,000 tonnes/year to be considered a "large final emitter" (under Alberta regulations). Enerplus does not have any operated facilities that meet this level; however, we do participate in a small number of partner-operated facilities that fall into this category. We also anticipate that our proposed Kirby project would fit this classification once operational. We will be evaluating carbon capture and storage alternatives for our Kirby development as a normal course of business.

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 environment responsibility and continued positive economic impact.

Appointment of New U.S. President of Operations

I am also pleased to announce that Mr. Dana Johnson has joined the Enerplus executive group as the President, U.S. Operations. Mr. Johnson brings over 25 years of oil and gas industry experience, the majority of which has been spent in the United States with Quicksilver Resources Inc. and Shell Exploration and Production Company. His background in both conventional and unconventional plays throughout Canada and the U.S. will be a tremendous asset to Enerplus in leading this operating division. Larry Hammond and Ray Daniels will continue to lead our Canadian conventional and oil sands divisions respectively.

The Future

While the oil and gas industry faces many challenges we believe there are also many opportunities in front of us. We continue to be committed to the long-term success of our business and are focused on improving our operations to the benefit of our unitholders. We believe that our unitholders have invested in Enerplus because of their desire for income. We plan to manage our business in order to provide that income today, tomorrow and beyond 2010 when the Canadian federal income trust tax is implemented. We will look to maximize our cash flow and provide an attractive yield to our investors through the effective use of our tax pools and our development capital expenditures. Our current balance sheet strength, the opportunities within our asset base and our technical expertise positions Enerplus for future success.

Gordon J. Kerr
President & Chief Executive Officer

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

The following discussion and analysis of financial results is dated May 8, 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 months ended March 31, 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 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. In addition to disclosing reserves under the requirements of NI 51-101, we also disclose our reserves on a company interest basis which is not a term defined under NI 51-101. This information may not be comparable to similar measures presented by other issuers. 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 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

On February 13, 2008 we successfully closed the largest transaction in our 22 year history, acquiring Focus Energy Trust ("Focus") for total consideration of $1.7 billion including approximately $357 million of assumed debt and working capital. The results of the quarter include the results of Focus from the date of closing. The integration of Focus is progressing well. The drilling programs at Tommy Lakes and Shackleton are on schedule. We retained approximately 88% of the Focus staff, excluding executives, and the offices have been successfully integrated.

Overall production was in-line with expectations although operating costs were slightly higher than anticipated due to optimization work in the United States and pipeline and facility issues on some non-operated Canadian properties. Our development capital spending in the first quarter of 2008 was on target as we successfully integrated and completed both the Focus and Enerplus first quarter development capital spending programs. In total we spent $126.3 million and drilled 125 net wells with a 100% success rate.

Cash flow from operating activities increased 33% to $256.2 million in the first quarter of 2008 compared to the same period in 2007. The increase was due to higher realized crude oil and natural gas prices along with increased production as a result of the Focus acquisition. The higher commodity prices increased our price risk management program costs as we incurred cash losses of $10.9 million and non-cash losses of $79.4 million due to higher forward commodity prices at quarter end.

We maintained our monthly cash distributions at $0.42 per unit during the first quarter with a payout ratio of 75% and our debt-to-cash flow remains at a conservative 1.0x (including both Enerplus' and Focus' trailing twelve month cash flow).

We continue to maintain our 2008 guidance targets of $580 million on development capital spending, operating costs of $8.65/BOE, G&A costs of $2.20/BOE, annual average production rate of 98,000 BOE/day and an exit production rate of 100,000 BOE/day.

Results of Operations

Production

Production in the first quarter of 2008 was in-line with our expectations averaging 89,150 BOE/day. March was the first full month of production from both Enerplus and Focus and the combined production averaged approximately 100,000 BOE/day.

On November 30, 2007 we experienced a fire at our Giltedge property that resulted in shut-in production of approximately 2,000 BOE/day that was not expected to be back on-line until mid-2008. We were able to bring a portion of the Giltedge production (460 BOE/day) back on-line earlier than expected in the first quarter of 2008. Successful waterflood activities at our Medicine Hat Glauconitic C property and optimization activities at our U.S. properties also resulted in higher than expected production during the quarter.

These increases were partially offset by lower production of approximately 200 BOE/day at Bantry North due to regulatory issues at two non-operated facilities during March. We worked closely with the operator and regulator and were able to resolve these issues subsequent to the quarter. We also had unplanned downtime at our non-operated Mitsue property and operated Chinchaga property resulting in shut-in production of approximately 700 BOE/day for the first quarter, however both Mitsue and Chinchaga were brought back on-line at the end of March.

Production volumes in the first quarter of 2008 were 4% higher than the first quarter of 2007 volumes of 86,028 BOE/day. Incremental production from the Focus assets beginning February 13, 2008 more than offset the production interruptions experienced at our Giltedge, Bantry, Mitsue and Chinchaga properties.

Average production volumes for the three months ended March 31, 2008 and 2007 are outlined below:

	Three months ended March 31,		
Daily Production Volumes	2008	2007	% Change
Natural gas (Mcf/day)	307,746	275,714	12%
Crude oil (bbls/day)	33,256	35,567	(6)%
Natural gas liquids (bbls/day)	4,603	4,509	2%
Total daily sales (BOE/day)	89,150	86,028	4%

Based on the results of our first 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 directly impact our earnings, cash flow and financial condition. The following table compares our average selling prices for the three months ended March 31, 2008 and 2007. It also compares the benchmark price indices for the same periods.

	Three months ended March 31,		
Average Selling Price[1]	2008	2007	% Change
Natural gas (per Mcf)	$ 7.52	$ 7.21	4%
Crude oil (per bbl)	86.02	57.26	50%
Natural gas liquids (per bbl)	69.75	44.09	58%
Per BOE	62.09	49.08	27%

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

	Three months ended March 31,		
Average Benchmark Pricing	2008	2007	% Change
AECO natural gas – monthly index (CDN$/Mcf)	$ 7.13	$ 7.46	(4)%
AECO natural gas – daily index (CDN$/Mcf)	7.90	7.41	7%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	8.07	6.96	16%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	8.07	8.19	(1)%
WTI crude oil (US$/bbl)	95.39	58.23	64%
WTI crude oil: CDN$ equivalent (CDN$/bbl)	95.39	68.51	39%
US$/CDN$ exchange rate	1.00	0.85	18%

Both natural gas and crude oil prices rose significantly during the first quarter. In the case of natural gas, the winter started off with very weak natural gas prices and a consensus for mild weather. However, actual weather was colder than normal across most of North America and imports of LNG to the U.S. fell considerably year-over-year, resulting in upward pressure on price throughout the first quarter as storage inventories fell. During the quarter prices at AECO rose 35% from a low of $6.88/Mcf to a high of $9.32/Mcf.

We realized an average price on our natural gas of $7.52/Mcf (net of transportation costs) during the three months ended March 31, 2008, an increase of 4% from $7.21/Mcf for the same period in 2007. In comparison to the first quarter of 2007, the AECO monthly index price for natural gas decreased 4% and the AECO daily index price increased 7%. We sell the majority of our natural gas under both month and day AECO index contracts. Our realized natural gas price increase of 4% during the first quarter was comparable to the average change in the combined indices.

The West Texas Intermediate ("WTI") crude oil price fell during January and early February, reaching a low of US$86.99/bbl, but then climbed to a high of US$110.33/bbl, before settling at US$101.58/bbl on March 31, 2008. Subsequent to the quarter end, the WTI price has increased a further 15% to 20%. A key driver for the price increase has been demand for commodities, including crude oil futures, as a hedge against inflation. Fundamentals were also supportive as global demand continued to grow during the quarter.

The average price we received for our crude oil during the three months ended March 31, 2008 increased 50% to $86.02/bbl (net of transportation costs) from $57.26/bbl during the same period in 2007. In comparison, the WTI crude oil benchmark price, in Canadian dollars, increased 39% from the corresponding period in 2007. The relative strength in our sales price increase can be attributed in large part to the reduced Giltedge heavy crude production. As a result heavy crude with its wide differential to WTI comprised a smaller portion of our overall volumes.

The Canadian dollar began the year at $0.99 per U.S. dollar, stronger than par, and fluctuated between $0.97 per U.S. dollar and $1.03 per U.S. dollar during the quarter. As a result of the Canadian dollar strengthening throughout 2007, the first quarter of 2008 average exchange rate increased 18% compared to the same period in 2007. As most of our crude oil and a portion of our natural gas are priced in reference to U.S. dollar denominated benchmarks, this movement in the exchange rate reduced the Canadian dollar prices that we would have otherwise realized.

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 while maintaining participation should commodity prices increase. 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 both by existing Focus hedges and by the objective to protect the downside and assure cash flow certainty during the first year of this significant acquisition.

Given the above framework and objectives, we entered into additional commodity contracts during the first quarter of 2008. Considering all financial contracts transacted as of April 28, 2008, we have protected a portion of our natural gas price risk through to October 31, 2009 and a portion of our crude oil price risk through to December 31, 2009. We also have protected 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 April 28, 2008, including positions entered into by Focus, expressed as a percentage of our forecasted net production volumes:

	Natural Gas (CDN$/Mcf)			Crude Oil (US$/bbl)		
	April 1, 2008 – October 31, 2008	November 1, 2008 – March 31, 2009	April 1, 2009 – October 31, 2009	April 1, 2008 – June 30, 2008	July 1, 2008 – December 31, 2008	January 1, 2009 – December 31, 2009
Floor Prices (puts)	$7.09	$ 8.66	–	$71.43	$72.09	$ 81.36
% (net of royalties)	25%	14%	–	38%	35%	16%
Fixed Price (swaps)	$7.44	$ 9.35	$7.86	$79.95	$79.97	$100.05
% (net of royalties)	20%	3%	1%	18%	19%	2%
Capped Price (calls)	$8.25	$11.24	–	$85.09	$85.48	$ 92.98
% (net of royalties)	25%	11%	–	24%	22%	12%

Based on weighted average price (before premiums), estimated average annual production of 98,000 BOE/day, and assuming for 2008 a 19% royalty rate. For 2009 we have assumed a 24% royalty rate reflecting the increased royalties for Alberta production at the current forward commodity price levels.

Accounting for Price Risk Management

During the first quarter of 2008 our price risk management program generated cash gains of $4.3 million on our natural gas contracts and cash losses of $15.2 million on our crude oil contracts. The natural gas cash gains are due to contracts in place that provided floor protection that was above market prices. The crude oil cash losses are the result of crude oil prices rising above our swap and sold call positions. In comparison, our first quarter of 2007 commodity price risk management program resulted in cash losses of $0.5 million on our natural gas contracts and cash gains of $8.4 million on our crude oil contracts.

At March 31, 2008 the fair value of our natural gas and crude oil derivative instruments, net of premiums, represent losses of $50.2 million and $77.9 million, respectively. The loss positions at March 31, 2008, which are due to forward natural gas and crude oil prices being above our sold call and swap positions, are recorded as current deferred financial credits on our balance sheet. In comparison, at December 31, 2007 the fair value of our natural gas and crude oil derivative instruments represented a gain of $9.7 million and a loss of $52.5 million respectively. Upon the closing of the Focus acquisition the fair value loss, included with the Focus assets, on both the natural gas derivative instruments of $1.6 million and crude oil derivative instruments of $4.3 million were recorded on our balance sheet. The change in the fair value of our derivative instruments during the quarter resulted in unrealized losses of $58.3 million for natural gas and $21.1 million for crude oil. As the forward markets for natural gas and crude oil fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as a non-cash charge or non-cash gain in earnings. See Note 9 for details.

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

Risk Management Gains/(Losses)	Three months ended March 31,		Three months ended March 31,	
($ millions, except per unit amounts)	2008		2007	
Cash (losses)/gains:				
Natural Gas	$ 4.3	$ 0.15/Mcf	$ (0.5)	$(0.02)/Mcf
Crude Oil	(15.2)	$ (5.03)/bbl	8.4	2.63/bbl
Total Cash (losses)/gains	$(10.9)	$ (1.35)/BOE	$ 7.9	$ 1.01/BOE
Non-cash losses on financial contracts:				
Change in fair value – natural gas	$(58.3)	$ (2.08)/Mcf	$(20.6)	$(0.83)/Mcf
Change in fair value – crude oil	(21.1)	(6.98)/bbl	(12.9)	(4.02)/bbl
Total non-cash losses	$(79.4)	$ (9.79)/BOE	$(33.5)	$(4.32)/BOE
Total losses	$(90.3)	$(11.14)/BOE	$(25.6)	$(3.31)/BOE

Cash Flow Sensitivity

The sensitivities below reflect the impact on cash flow per trust unit for the remaining three quarters of 2008 and include the commodity contracts described in Note 9 as well as the impact of 2008 forward market prices as at April 21, 2008. To the extent the market price of crude oil and natural gas change significantly from the April 21, 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	$0.06
Change of US$1.00 per barrel in the price of WTI crude oil	$0.04
Change of 1,000 BOE/day in production	$0.10
Change of $0.01 in the US$/CDN$ exchange rate	$0.10
Change of 1% in interest rate	$0.05

(1) Assumes constant working capital and 160,147,000 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 for the three months ended March 31, 2008 were $503.7 million ($510.0 million, net of $6.3 million of transportation costs), an increase of 33% or $123.7 million compared to $380.0 million ($385.9 million, net of $5.9 million of transportation costs) in the first quarter 2007. Increased gas production as a result of the Focus acquisition and substantially higher crude oil prices were the primary reasons for the higher revenues.

Analysis of Sales Revenue[(1)] ($ millions)	Crude oil	NGLs	Natural Gas	Total
Quarter ended March 31, 2007	$183.3	$17.9	$178.8	$380.0
Price variance[(1)]	87.0	10.7	12.4	110.1
Volume variance	(10.0)	0.6	23.0	13.6
Quarter ended March 31, 2008	**$260.3**	**$29.2**	**$214.2**	**$503.7**

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

Other Income

Other income for the three months ended March 31, 2008 was $15.1 million compared to $14.2 million for the three months ended March 31, 2007. During the first quarter of 2008 we realized 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 months ended March 31, 2008 and 2007 royalties were $93.8 million and $71.6 million respectively, approximately 19% of oil and gas sales, net of transportation costs. Overall, royalties increased primarily as a result of additional revenue from higher oil prices and the additional Focus assets acquired.

In October 2007, the Alberta government announced a 'New Royalty Framework' ("NRF") which will be effective January 1, 2009. In the context of an annualized 2008 forward market outlook of $110.00/bbl crude oil and $9.00/Mcf natural gas, and relative to Enerplus' current properties and production profile in Alberta, we estimate the incremental annual impact of the NRF to be approximately $90 to $100 million.

In April 2008, the Alberta government announced some changes to the NRF to encourage the development of deep, high-cost oil and gas reserves. These programs will be implemented on January 1, 2009 along with the NRF. These new programs are not expected to have a significant effect on our 2008 capital plans. Had these new programs been in place during 2007, approximately 23 gross (5 net) of Enerplus' natural gas wells drilled in 2007 would have qualified for potential royalty credits totaling $0.8 million. Our crude oil wells would not have been affected.

We continue to expect royalties to be approximately 19% of oil and gas sales, net of transportation costs for 2008. In 2009 given current commodity prices, we estimate the average royalty rate for the Fund including all royalties will be approximately 24% 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 administration 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 for the three months ended March 31, 2008 were $8.88/BOE or $72.0 million, compared to $8.53/BOE or $66.0 million for the same period in 2007. Excluding the non-cash gain included in operating expenses related to our electricity swaps, operating costs were $8.96/BOE compared to $8.55/BOE for the same period in 2007. We had higher operating costs at our Mitsue and Chinchaga properties due to costs associated with pipeline and facility issues along with additional optimization expenses on our U.S. properties. Partially offsetting these increases was the addition of lower operating cost properties from Focus beginning February 13, 2008.

We are maintaining our annual guidance for operating costs of approximately $8.65/BOE.

General and Administrative Expenses ("G&A")

During the first quarter of 2008 G&A expenses decreased 8% to $2.03/BOE or $16.4 million compared to $2.21/BOE or $17.1 million for the first quarter of 2007. Total cash G&A was relatively unchanged year-over-year, with higher overall salary and benefits costs offset by lower long term cash compensation charges which are impacted by our trust unit price.

During the quarter our G&A expenses included non-cash charges for our trust unit rights incentive plan of $1.5 million or $0.18/BOE compared to $2.1 million or $0.27/BOE for 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 March 31,	
($ millions)	**2008**	2007
Cash	**$14.9**	$15.0
Trust unit rights incentive plan (non-cash)	**1.5**	2.1
Total G&A	**$16.4**	$17.1
(Per BOE)	**2008**	2007
Cash	**$1.85**	$1.94
Trust unit rights incentive plan (non-cash)	**0.18**	0.27
Total G&A	**$2.03**	$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 (see Note 6).

Interest on long-term debt for the three months ended March 31, 2008 totaled $13.3 million, a $3.6 million increase from $9.7 million during the comparable quarter of 2007. The increase was due to higher average indebtedness partially offset by a lower weighted average interest rate of 4.3% during the first three months of 2008 compared to 4.9% in the same period in 2007.

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

Interest Expense	Three months ended March 31,	
($ millions)	**2008**	2007
Interest on long-term debt	$13.3	$ 9.7
Unrealized gain	(6.3)	(1.6)
Total Interest Expense	$ 7.0	$ 8.1

At March 31, 2008 approximately 12% of our debt was based on fixed interest rates while 88% had floating interest rates. In comparison, at March 31, 2007 approximately 19% of our debt was based on fixed interest rates and 81% was floating. The increased percentage of floating rate debt is due to the bank debt that was assumed with the Focus acquisition.

Capital Expenditures

During the first quarter of 2008 we spent $126.3 million on development capital and facilities, an increase of $16.3 million or 15% compared to the same period in 2007. The increase was largely due to the successful completion of Focus' original development capital program and drilling an additional two wells at Tommy Lakes. Our development capital program is expected to remain on target through the remainder of the year. To date we have achieved a 100% success rate with our drilling program on 125 net wells.

Property acquisitions during the three months ended March 31, 2008 were $7.5 million compared to $63.4 million during the three months ended March 31, 2007 which related primarily to the acquisition of gross-overriding royalty interests in the Jonah natural gas field in Wyoming. Our corporate acquisition of Focus closed during the quarter for consideration of approximately $1.7 billion. Refer to Note 4 for further details.

Total net capital expenditures of approximately $1.9 billion for the first quarter of 2008 compared to $174.8 million for the first quarter of 2007 are outlined below.

Capital Expenditures ($ millions)	Three months ended March 31, 2008	2007
Development expenditures	$ 109.3	$ 90.8
Plant and facilities	17.0	19.2
Development Capital	126.3	110.0
Office	1.6	1.4
Sub-total	127.9	111.4
Acquisitions of oil and gas properties[1]	7.5	63.4
Corporate Acquisitions	1,757.5	–
Dispositions of oil and gas properties[1]	(2.1)	–
Total Net Capital Expenditures	$1,890.8	$174.8
Total Capital Expenditures financed with cash flow	$ 63.9	$ 35.5
Total Capital Expenditures financed with debt and equity	1,826.9	139.3
Total Net Capital Expenditures	$1,890.8	$174.8

[1] Net of post-closing adjustments.

We are maintaining our 2008 guidance of $580 million for annual development capital spending.

Oil Sands

Our Joslyn and Kirby 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.

During the first quarter of 2008 we capitalized costs of $0.7 million related to Joslyn as we continued to build the steam chambers in producing wells and bring two wells back on production that had workovers completed at year end. At our Kirby project we capitalized approximately $20.6 million and were successful in completing our core hole drilling program drilling 55 core holes and 3 water source/disposal wells. At March 31, 2008 capitalized costs life-to-date for Joslyn were $117.1 million and for Kirby were $226.0 million for a combined total of $343.1 million.

On March 25, 2008 we announced that we are commencing a review of strategic options regarding our 15% working interest in Joslyn. A review of our portfolio of oil sands and conventional projects has resulted in the decision to consider options to rebalance the portfolio. Our distribution-oriented business model necessitates a portfolio of assets that provide near-term cash flow, future growth potential and an appropriate balance of commodities. While we believe that both Joslyn and Kirby provide attractive long-term potential, the operated nature of the Kirby project provides enhanced control over the timing and nature of our capital spending profile. Should the review result in a decision to sell all or a portion of Joslyn, sale proceeds would initially be used to reduce our outstanding bank debt. Given our conservative balance sheet, such sale proceeds would reinforce our borrowing capacity, enhance our ability to fund future capital spending and acquisition activity and minimize the need for future 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 March 31, 2008 DDA&A increased to $139.8 million or $17.23/BOE compared to $119.1 million or $15.38/BOE during the same 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 March 31, 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.

The Fund has estimated the net present value of its total asset retirement obligations to be approximately $204.3 million at March 31, 2008 compared to $165.7 million at December 31, 2007. The increase of $38.6 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 March 31,	
($ millions)	**2008**	2007
Amortization of the asset retirement cost	**$4.7**	$3.4
Accretion of the asset retirement obligation	**2.5**	1.7
Total Amortization and Accretion	**$7.2**	$5.1
Asset Retirement Obligations Settled	**$4.0**	$3.3

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 basis 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 $35.2 million for the quarter ended March 31, 2008 compared to a recovery of $23.7 million for the same period in 2007. Approximately $10.7 million of the additional recovery is attributed to Focus and another $2.8 million relates to a British Columbia corporate income tax rate reduction which became effective during the quarter.

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's 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 $2.7 million in first quarter of 2008.

The amount of current taxes recorded throughout the year on 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 months ended March 31, 2008 our U.S. operations incurred taxes (income and withholding) in the amount of $12.2 million compared to $2.0 million for the same period in 2007. The increase in current taxes was due to an increase in net income combined with a decrease in capital expenditures during the quarter.

We have increased our guidance by 5% for 2008 as we now expect our U.S. current income and withholding taxes to average approximately 25% of cash flow from U.S. operations. This guidance is based on current commodity prices, our current development capital program and assumes all funds in excess of U.S. development capital spending are repatriated to Canada.

Effective January 1, 2011 we will be subject to the Specified Investment Flow-Through ("SIFT") tax should we remain a trust. The Federal budget on February 26, 2008 proposed that for 2009 tax years and later the SIFT tax will be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. These proposals would result in a SIFT being taxed on the same basis as a corporation.

Net Income

Net income for the first quarter of 2008 was $121.4 million or $0.82 per trust unit compared to $107.9 million or $0.88 per trust unit in the same period for 2007. The $13.5 million increase in net income was primarily due to an increase in oil and gas sales of $124.2 million and an increase in future income tax recovery of $11.4 million offset by increased risk management costs of $64.8 million, increased royalties of $22.3 million and increased DDA&A of $20.7 million.

Cash Flow from Operating Activities

Cash flow for the three months ended March 31, 2008 was $256.2 million or $1.74 per trust unit compared to $193.2 million or $1.57 per trust unit for the same period in 2007. The increase in cash flow per unit is largely due to realizing a higher weighted average sales price on our crude oil and natural gas sales combined with an increase in production, offset by higher cash risk management costs, royalties and operating costs.

Selected Financial Results

	Three months ended March 31, 2008			Three months ended March 31, 2007		
Per BOE of production (6:1)	Operating Cash Flow[1]	Non-Cash & Other Items	Total	Operating Cash Flow[1]	Non-Cash & Other Items	Total
Production per day			89,150			86,028
Weighted average sales price[2]	$ 62.10	$ –	$ 62.10	$49.08	$ –	$ 49.08
Royalties	(11.57)	–	(11.57)	(9.12)	–	(9.12)
Commodity derivative instruments	(1.35)	(9.79)	(11.14)	1.01	(4.32)	(3.31)
Operating costs	(8.96)	0.08	(8.88)	(8.55)	0.02	(8.53)
General and administrative	(1.85)	(0.18)	(2.03)	(1.94)	(0.27)	(2.21)
Interest expense, net of interest and other income	(0.79)	0.77	(.02)	(1.25)	0.21	(1.04)
Foreign exchange gain/(loss)	(0.05)	(0.39)	(0.44)	(0.07)	0.01	(0.06)
Capital taxes	–	–	–	(0.12)	–	(0.12)
Current income tax	(1.18)	–	(1.18)	(0.26)	–	(0.26)
Restoration and abandonment cash costs	(0.50)	0.50	–	(0.42)	0.42	–
Depletion, depreciation, amortization and accretion	–	(17.23)	(17.23)	–	(15.38)	(15.38)
Future income tax recovery	–	4.33	4.33	–	3.06	3.06
Gain on sale of marketable securities[3]	–	1.02	1.02	–	1.82	1.82
Total per BOE	$ 35.85	$(20.89)	$ 14.96	$28.36	$(14.43)	$ 13.93

(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 table provides a geographical analysis of key operating and financial results for the three months ended March 31, 2008 and 2007.

(CDN$ millions, except per unit amounts)	Three months ended March 31, 2008			Three months ended March 31, 2007		
	Canada	U.S.	Total	Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	295,799	11,947	307,746	266,050	9,664	275,714
Crude oil (bbls/day)	23,734	9,522	33,256	25,330	10,237	35,567
Natural gas liquids (bbls/day)	4,603	–	4,603	4,509	–	4,509
Total Daily Sales (BOE/day)	77,637	11,513	89,150	74,180	11,848	86,028
Pricing(1)						
Natural gas (per Mcf)	$ 7.47	$ 8.95	$ 7.52	$ 7.21	$ 7.29	$ 7.21
Crude oil (per bbl)	84.31	90.30	86.02	54.94	62.99	57.26
Natural gas liquids (per bbl)	69.75	–	69.75	44.09	–	44.09
Capital Expenditures						
Development capital and office	$ 108.3	$ 19.6	$ 127.9	$ 73.6	$ 37.8	$ 111.4
Acquisitions of oil and gas properties	7.4	0.1	7.5	2.1	61.3	63.4
Dispositions of oil and gas properties	(2.1)	–	(2.1)	–	–	–
Revenues						
Oil and gas sales(1)	$ 415.7	$ 88.0	$ 503.7	$ 315.6	$ 64.4	$ 380.0
Royalties(2)	(75.2)	(18.6)	(93.8)	(58.9)	(12.7)	(71.6)
Financial contracts	(90.3)	–	(90.3)	(25.6)	–	(25.6)
Expenses						
Operating	$ 68.6	$ 3.4	$ 72.0	$ 63.9	$ 2.1	$ 66.0
General and administrative	15.1	1.3	16.4	14.8	2.3	17.1
Depletion, depreciation, amortization and accretion	118.4	21.4	139.8	91.5	27.6	119.1
Current income taxes (recovery)/expense	(2.7)	12.2	9.5	–	2.0	2.0

(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 for the first quarter of 2008 increased over the fourth quarter of 2007 as crude oil and natural gas prices began to increase. Overall oil and gas sales were lower in 2007 from 2006 as a result of softening natural gas prices throughout 2006 and remained lower during 2007 as a result of lower production.

Net income has been affected by fluctuating commodity prices and risk management costs, the strengthening Canadian dollar, higher operating and G&A costs, changes in future tax provisions as well as changes to accounting policies adopted during 2007. Furthermore, changes in the fair value of all our financial derivative instruments (commodity, interest and foreign exchange) are impacted by future prices causing net income to fluctuate between quarters.

Quarterly Financial Information	Oil and Gas		Net Income per trust unit	
($ millions, except per trust unit amounts)	Sales[1]	Net Income	Basic	Diluted
2008				
First quarter	$ 503.7	$121.4	$0.82	$0.82
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 associated with Bill C-52. 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 forecasted 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 first quarter of 2008 cash distributions of $192.4 million were funded entirely through cash flow of $256.2 million.

Our payout ratio, which is calculated as cash distributions divided by cash flow, was 75% for the three months ended March 31, 2008 compared to 82% for the same period in 2007.

In aggregate, our 2008 first quarter cash distributions of $192.4 million and our development capital and office expenditures of $127.9 million totaled $320.3 million, or approximately 125% of our cash flow of $256.2 million. We rely on access to capital markets to the extent cash distributions combined with development capital and office expenditures exceed cash flow. Over the long term we would expect to support our distributions and capital expenditures with our cash flow, however we would continue to fund acquisitions and growth through additional debt and equity. There will be years when we are investing capital in opportunities that do not immediately generate cash flow (such as our Joslyn and Kirby oil sands projects) where this relationship will vary. Despite our 2008 first quarter cash flow being less than the aggregate of our cash distributions and development capital, we continue to have conservative debt levels with a trailing twelve month debt-to-cash flow ratio of 1.0x at March 31, 2008.

For the three months ended March 31, 2008, our cash distributions exceeded our net income by $71.0 million (2007 – $49.8 million). Net income includes $181.7 million of non-cash items (2007 – $129.0 million) such as DDA&A, changes in the fair value of our derivative instruments based on forward markets, and future income taxes that 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.

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 March 31, 2008	Year ended December 31, 2007	Year ended December 31, 2006
Cash flow from operating activities:	$256.2	$ 868.5	$863.7
Cash distributions	192.4	646.8	614.3
Excess of cash flow over cash distributions	$ 63.8	$ 221.7	$249.4
Net income	$121.4	$ 339.7	$544.8
Shortfall of net income over cash distributions	$ (71.0)	$(307.1)	$ (69.5)
Cash distributions per weighted average trust unit	$ 1.30	$ 5.07	$ 5.05
Payout ratio(1)	75%	74%	71%

(1) Based on cash distributions divided by cash flow from operating activities.

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 disclose maintenance capital separately from development capital spending.

Long-Term Debt

Long-term debt at March 31, 2008 was $1,099.3 million, an increase of $372.6 million from $726.7 million at December 31, 2007.

Long-term debt at March 31, 2008 is comprised of $860.9 million of bank indebtedness, which increased $363.5 million from December 31, 2007 and $238.4 million of senior unsecured notes. The increase in long-term debt is mainly due to the $330.9 million of debt that was assumed on the Focus acquisition along with debt incurred to fund our development capital program.

Our working capital deficiency, excluding cash, at March 31, 2008 increased $63.3 million to $266.7 million from $203.4 million at December 31, 2007. Excluding current deferred financial assets and credits and the related current future income taxes, our working capital deficiency increased by $1.0 million compared to December 31, 2007. The increase in accounts receivable that is attributable to higher commodity prices and production levels offset the increase in accounts payable that resulted from higher capital spending activity and increased distributions payable for units issued in conjunction with the Focus acquisition.

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

Financial Leverage and Coverage	March 31, 2008	December 31, 2007
Long-term debt to trailing cash flow	1.0x[(1)]	0.8x
Cash flow to interest expense	19.3x[(1)]	25.8x
Long-term debt to long-term debt plus equity	22%	22%

Long-term debt is measured net of cash.
Cash flow and interest expense are 12-months trailing.
(1) Includes both Enerplus' and Focus' 12 month trailing cash flows and interest expense.

At March 31, 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 March 31, 2008 we are in compliance with our debt covenants, the most restrictive of which limits our long-term debt to three times trailing cash flow reflecting acquisitions on a pro forma basis. 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 anticipate that we will 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.

Commitments

Upon the completion of the Focus acquisition we assumed an office lease with commitments of $0.9 million a year for 3 years and transportation contracts resulting in a total commitment of $40.0 million over a variety of terms the longest of which is 10 years. The Focus natural gas term transportation contracts are comprised of 40 MMcf/day in British Columbia, and 65 MMcf/day in Saskatchewan.

Trust Unit Information

We had 164,142,000 trust units outstanding at March 31, 2008. This includes the 30,150,000 units issued on February 13, 2008 to acquire Focus and the 9,087,000 exchangeable partnership units outstanding that were assumed with the Focus acquisition which are convertible at the option of the holder into 0.425 of an Enerplus trust unit (3,862,000 trust units). This compares to 123,434,000 trust units at March 31, 2007 and 129,813,000 trust units outstanding at December 31, 2007. Including the exchangeable partnership units the weighted average basic number of trust units outstanding during the first quarter of 2008 was 147,482,000 (2007 – 123,282,000). At May 6, 2008 we had 164,420,000 trust units outstanding including the equivalent partnership units.

During the three months ended March 31, 2008 317,000 trust units (2007 – 283,000) 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 $11.9 million (2007 – $13.0 million) of additional equity to the Fund. For further details see Note 8.

Canadian and U.S. Taxpayers

Enerplus estimates that approximately 95% of cash distributions paid to Canadian unitholders and 90% of cash distributions paid to U.S. unitholders will be taxable and the remaining 5% and 10% 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. On March 24, 2007, Bill 1672 was introduced into the U.S. House of Representatives which, if enacted as presented, would make dividends from Canadian income funds such as Enerplus ineligible for treatment as a "Qualified Dividend". The dividends would then become a "non-qualified dividend from a foreign corporation" subject to the normal rates of tax commencing with dividends received after the date of enactment. The proposed bill still requires the approval of the House of Representatives, the Senate and the President prior to it being enacted. Therefore, we are unable to determine when or even if the bill will become enacted as presented.

In April 2008, Enerplus estimated its non-resident ownership to be approximately 65%.

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 and will continue to evolve our strategies and responses to the plan. Draft regulations under the plan are expected to be published in the latter half of this year for public comment. Under the proposed plan, the oil and gas industry will be required to reduce its emissions intensity from 2006 levels by 18% by 2010 and 2% every following year. The proposed federal regulations also require oil sands upgraders and in-situ projects to meet certain carbon capture and storage targets by 2018. Given Enerplus' interest in various oil sands development areas (Kirby, Joslyn and Laricina), we will be closely monitoring the development of the proposed federal regulations.

In January, 2008, the Government of Alberta released its new climate change strategy. The Alberta strategy focuses on the three areas of carbon capture and storage, conserving and using energy more efficiently and "greening" energy production. The provincial government will be providing updates as to its specific plans for implementation of various portions of its strategy. Certain climate change regulations came in to effect in Alberta on July 1, 2007 which set an emissions level of 100,000 tonnes/year to be considered a "large final emitter" (under Alberta regulations). Enerplus does not have any operated facilities that meet this level; however, we do participate in a small number of partner-operated facilities that fall into this category. We also anticipate that our proposed Kirby project would fit this classification once operational. We will be evaluating carbon capture and storage alternatives for our Kirby development as a normal course of business.

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 environment responsibility and continued positive economic impact. At this stage, without further clarity and specific details from the governments of Canada and Alberta, 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 March 31, 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", "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; future payout ratio; future tax treatment of income trusts such as the Fund; future structure of the Fund and its subsidiaries; the Fund's tax pools; the volumes and estimated value of the Fund's oil and gas reserves and resources; the volume and product mix of the Fund's oil and gas production; future oil and natural gas prices and the Fund's commodity risk management programs; the amount of future asset retirement obligations; future liquidity and financial capacity; future results from operations, cost estimates and royalty rates; future 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 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; the impact of competitors; 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.

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)	March 31, 2008	December 31, 2007
Assets		
Current assets		
Cash	$ 1,453	$ 1,702
Accounts receivable	247,675	145,602
Deferred financial assets (Note 9)	1,102	10,157
Future income taxes	33,284	10,807
Other current	3,807	6,373
	287,321	174,641
Property, plant and equipment (Note 2)	5,652,942	3,872,818
Goodwill (Note 4)	604,645	195,112
Other assets (Note 9)	49,966	60,559
	$ 6,594,874	$ 4,303,130
Liabilities		
Current liabilities		
Accounts payable	$ 355,464	$ 269,375
Distributions payable to unitholders	68,939	54,522
Deferred financial credits (Note 9)	128,145	52,488
	552,548	376,385
Long-term debt (Note 5)	1,099,274	726,677
Deferred financial credits (Note 9)	77,769	90,090
Future income taxes	696,183	304,259
Asset retirement obligations (Note 3)	204,327	165,719
	2,077,553	1,286,745
Equity		
Unitholders' capital (Note 8)	5,407,195	4,032,680
Accumulated deficit	(1,354,917)	(1,283,953)
Accumulated other comprehensive income	(87,505)	(108,727)
	(1,442,422)	(1,392,680)
	3,964,773	2,640,000
	$ 6,594,874	$ 4,303,130

CONSOLIDATED STATEMENTS OF ACCUMULATED DEFICIT

	Three months ended March 31,	
(CDN$ thousands) (Unaudited)	2008	2007
Accumulated income, beginning of period	$ 2,286,927	$ 1,952,960
Adjustment for adoption of financial instruments standards	–	(5,724)
Revised accumulated income, beginning of period	2,286,927	1,947,236
Net income	121,394	107,873
Accumulated income, end of period	$ 2,408,321	$ 2,055,109
Accumulated cash distributions, beginning of period	$(3,570,880)	$(2,924,045)
Cash distributions	(192,358)	(157,671)
Accumulated cash distributions, end of period	$(3,763,238)	$(3,081,716)
Accumulated deficit, end of period	$(1,354,917)	$(1,026,607)

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

	Three months ended March 31,	
(CDN$ thousands) (Unaudited)	2008	2007
Balance, beginning of period	$(108,727)	$ (8,979)
Transition adjustments on adoption:		
Cash flow hedges	–	660
Available for sale marketable securities	–	14,252
Other comprehensive income/(loss)	21,222	(21,458)
Balance, end of period	$ (87,505)	$(15,525)

CONSOLIDATED STATEMENTS OF INCOME

(CDN$ thousands except per trust unit amounts) (Unaudited)	Three months ended March 31, 2008	2007
Revenues		
Oil and gas sales	$510,069	$385,871
Royalties	(93,836)	(71,565)
Commodity derivative instruments (Note 9)	(90,379)	(25,606)
Other income	15,116	14,160
	340,970	302,860
Expenses		
Operating	72,016	66,030
General and administrative	16,437	17,110
Transportation	6,317	5,864
Interest (Note 6)	6,988	8,115
Foreign exchange (Note 7)	3,684	482
Depletion, depreciation, amortization and accretion	139,794	119,091
	245,236	216,692
Income before taxes	95,734	86,168
Current taxes	9,541	2,047
Future income tax recovery	(35,201)	(23,752)
Net Income	$121,394	$107,873
Net income per trust unit		
Basic	$ 0.82	$ 0.88
Diluted	$ 0.82	$ 0.87
Weighted average number of trust units outstanding (thousands)[1]		
Basic	147,482	123,282
Diluted	147,583	123,363

[1] Includes the exchangeable partnership units.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(CDN$ thousands) (Unaudited)	Three months ended March 31, 2008	2007
Net income	$121,394	$107,873
Other comprehensive income/(loss), net of tax:		
Unrealized gain/(loss) on marketable securities	2,578	(3,156)
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	74	(204)
Change in cumulative translation adjustment	24,728	(6,444)
Other comprehensive income/(loss)	21,222	(21,458)
Comprehensive income	$142,616	$ 86,415

CONSOLIDATED STATEMENTS OF CASH FLOWS

(CDN$ thousands) (Unaudited)	Three months ended March 31, 2008	2007
Operating Activities		
Net income	$ 121,394	$ 107,873
Non-cash items add/(deduct):		
Depletion, depreciation, amortization and accretion	139,794	119,091
Change in fair value of derivative instruments (Note 9)	66,472	34,847
Unit based compensation (Note 8)	1,486	2,111
Foreign exchange on translation of senior notes (Note 7)	9,233	(2,882)
Future income tax	(35,201)	(23,752)
Amortization of senior notes premium	(153)	(169)
Reclassification adjustments from AOCI to net income	92	(204)
Gain on sale of marketable securities	(8,263)	(14,055)
Asset retirement obligations settled (Note 3)	(4,020)	(3,314)
	290,834	219,546
Increase in non-cash operating working capital	(34,618)	(26,365)
Cash flow from operating activities	256,216	193,181
Financing Activities		
Issue of trust units, net of issue costs (Note 8)	11,885	13,020
Cash distributions to unitholders	(192,358)	(157,671)
Increase in bank credit facilities	32,602	100,342
Decrease in non-cash financing working capital	14,417	2,369
Cash flow from financing activities	(133,454)	(41,940)
Investing Activities		
Capital expenditures	(127,923)	(111,354)
Property acquisitions	(7,549)	(63,423)
Property dispositions	2,122	–
Proceeds on sale of marketable securities	18,320	16,467
Increase in non-cash investing working capital	(10,418)	6,130
Cash flow from investing activities	(125,448)	(152,180)
Effect of exchange rate changes on cash	2,437	909
Change in cash	(249)	(30)
Cash, beginning of period	1,702	124
Cash, end of period	$ 1,453	$ 94
Supplementary Cash Flow Information		
Cash income taxes paid	$ 9,002	$ 3,241
Cash interest paid	$ 8,318	$ 6,086

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)	March 31, 2008	December 31, 2007
Property, plant and equipment	$ 8,355,812	$ 6,429,241
Accumulated depletion, depreciation and accretion	(2,702,870)	(2,556,423)
Net property, plant and equipment	$ 5,652,942	$ 3,872,818

Capitalized development general and administrative ("G&A") expense of $4,909,000 (2007 – $4,019,000) is included in PP&E for the three months ended March 31, 2008. Excluded from PP&E for the depletion and depreciation calculation is $343,073,000 (2007 – $90,678,000) 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)	Three months ended March 31, 2008	Year ended December 31, 2007
Asset retirement obligations, beginning of period	$165,719	$123,619
Corporate acquisition	36,784	–
Changes in estimates	1,500	46,000
Acquisition and development activity	1,927	6,441
Dispositions	(110)	(756)
Asset retirement obligations settled	(4,020)	(16,280)
Accretion expense	2,527	6,695
Asset retirement obligations, end of period	$204,327	$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 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 Partnership Unit. Total consideration was approximately $1,366,494,000, consisting of 30,149,752 trust units issued, 9,086,666 exchangeable 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 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)	March 31, 2008	December 31, 2007
Bank credit facilities (a)	$ 860,863	$497,347
Senior notes (b)		
US$175 million (issued June 19, 2002)	182,904	175,973
US$54 million (issued October 1, 2003)	55,507	53,357
Total long-term debt	$1,099,274	$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 three months ended March 31, 2008 was 4.3% (March 31, 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 CAD/US exchange rate of 1.02 or CAD $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 March 31, 2008 the amortized cost of the US$175,000,000 senior notes was US$177,940,000.

6. INTEREST EXPENSE

	Three months ended March 31,	
($ thousands)	2008	2007
Realized		
Interest on long-term debt	$13,345	$ 9,748
Unrealized		
Gain on cross currency interest rate swap	(8,344)	(1,283)
Loss on interest rate swaps	2,140	(181)
Amortization of the premium on senior unsecured notes	(153)	(169)
Interest Expense	$ 6,988	$ 8,115

7. FOREIGN EXCHANGE

	Three months ended March 31,	
($ thousands)	2008	2007
Unrealized foreign exchange loss/(gain) on translation of U.S. dollar denominated senior notes	$ 9,233	$(2,882)
Unrealized foreign exchange (gain)/loss on cross currency interest rate swap	(4,171)	2,776
Unrealized foreign exchange (gain)/loss on foreign exchange swaps	(1,946)	–
Realized foreign exchange loss	568	588
Foreign exchange loss	$ 3,684	$ 482

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)	Three months ended March 31, 2008	Year ended December 31, 2007
Trust units	$5,239,767	$4,020,228
Exchangeable partnership units	154,551	–
Contributed surplus	12,877	12,452
Balance, end of period	$5,407,195	$4,032,680

(a) Trust Units

Authorized: Unlimited number of trust units

	Three months ended March 31, 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	53	1,636	205	6,758
Trust unit rights incentive plan (non-cash) – exercised	–	1,061	–	2,288
DRIP*, net of redemptions	264	10,249	1,102	50,053
Issued for acquisition of corporate and property interests (non-cash)	30,150	1,206,593	1,105	54,750
	160,280	$5,239,767	129,813	$4,020,228
Equivalent exchangeable partnership units	3,862	154,551	–	–
Balance, end of period	164,142	$5,394,318	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 Partnership Units

In conjunction with the Focus acquisition 9,086,666 Focus Exchangeable Limited Partnership Units 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 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 partnership units after January 8, 2017, unless certain conditions are met to permit an earlier redemption date. The exchangeable partnership units are not listed on any stock exchange and are not transferable. The exchangeable 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. The Focus Exchangeable Limited Partnership Units have been renamed Enerplus Exchangeable Limited Partnership Units.

No exchangeable partnership units were converted into trust units during the period February 13, 2008 to March 31, 2008. As at March 31, 2008, the 9,086,666 outstanding exchangeable partnership units represent the equivalent of 3,861,833 trust units.

	Three months ended March 31, 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	–	–	–	–
Balance, end of period	9,087	$154,551	–	$ –

(c) Contributed Surplus

Contributed surplus ($ thousands)	Three months ended March 31, 2008	Year ended December 31, 2007
Balance, beginning of period	$12,452	$ 6,305
Trust unit rights incentive plan (non-cash) – exercised	(1,061)	(2,288)
Trust unit rights incentive plan (non-cash) – expensed	1,486	8,435
Balance, end of period	$12,877	$12,452

(d) Trust Unit Rights Incentive Plan

As at March 31, 2008 a total of 4,458,000 rights issued pursuant to the Trust Unit Rights Incentive Plan ("Rights Incentive Plan") with an average exercise price of $45.77 were outstanding. This represents 2.8% of the total trust units outstanding of which 1,544,000 rights, with an average exercise price of $44.56, 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 three months ended March 31, 2008 reduced the exercise price of the outstanding rights by $0.43 per trust unit effective July 2008.

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

	Three months ended March 31, 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	1,273	42.05	816	48.71
Exercised	(53)	31.10	(205)	32.90
Cancelled	(166)	48.53	(286)	50.74
End of period	4,458	$45.77	3,404	$47.59
Rights exercisable at end of period	1,544	$44.56	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 of $1,486,000 ($0.01 per unit) related to rights issued were charged to general and administrative expense during the three months ended March 31, 2008 (March 31, 2007 – $2,111,000, $0.02 per unit).

(e) Basic and Diluted per Trust Unit Calculations

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

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

	Three months ended March 31,	
(thousands)	2008	2007
Weighted average trust units	145,487	123,282
Weighted average exchangeable partnership units[1]	1,995	–
Basic weighted average units outstanding	147,482	123,282
Dilutive impact of rights	101	81
Diluted weighted average units outstanding	147,583	123,363

(1) Based on the exchange ratio of 0.425

(f) Performance Trust Unit Plan

In 2007 the Board of Directors, upon recommendation of the Compensation Committee, approved new Performance Trust Unit ("PTU") plans for executives and employees. Under the plans employees and officers 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 period ended March 31, 2008 the Fund recorded cash compensation costs of $1,083,000 ($345,000 period ended March 31, 2007) under the plan which are included in general and administrative expenses.

At March 31, 2008 there were 422,000 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 March 31, 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 March 31, 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 March 31, 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 March 31, 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 March 31, 2008 the carrying value of the bank credit facilities approximated their fair value.

US$54 million senior notes and US$175 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 March 31, 2008 the Canadian dollar amortized cost of the senior notes was approximately $55,507,000 and the fair value of these notes was approximately $57,657,000.

US$175 million senior notes

The US$175,000,000 million senior notes, which are classified as other liabilities, are reported at amortized cost of US$177,940,000 and are translated to Canadian dollars at the period end exchange rate. At March 31, 2008 the Canadian dollar amortized cost of the senior notes was approximately $182,904,000 and the fair value of these notes was $199,396,000.

(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 March 31, 2008 a current deferred financial asset of $1,102,000, a current deferred financial credit of $128,145,000 and a long-term deferred financial credit of $77,769,000 are recorded on the consolidated balance sheet.

The deferred financial credit relating to crude oil instruments of $77,919,000 at March 31, 2008 consists of the fair value of the financial instruments, representing a loss position of $70,348,000, plus the related deferred premiums of $7,571,000. The deferred financial credit relating to natural gas instruments of $50,225,000 at March 31, 2008 consists of the fair value of the financial instruments of $48,179,000 plus the related deferred premiums of $2,047,000.

The following table summarizes the fair value as at March 31, 2008 and change in fair value for the period ended March 31, 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), beginning of period	$ (226)	$(89,439)	$ (425)	$ 450	$(56,783)[1]	$ 8,083[2]	$(138,340)
Change in fair value asset/(credits)	(2,140)[3]	12,515[4]	1,946[5]	652[6]	(21,136)[7]	(58,309)[7]	(66,472)
Deferred financial assets/(credits), end of period	$(2,366)	$(76,924)	$1,521	$1,102	$(77,919)	$(50,226)	$(204,812)
Balance sheet classification:							
Current asset/(liability)	$ –	$ –	$ –	$1,102	$(77,919)	$(50,226)	$(127,043)
Non-current asset/(liability)	$(2,366)	$(76,924)	$1,521	$ –	$ –	$ –	$ (77,769)

(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 $4,171) and interest expense (gain of $8,344).
(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 March 31, 2008	2007
Loss due to change in fair value	$79,445	$33,482
Net realized cash losses/(gains)	10,934	(7,876)
Commodity derivative instruments loss	$90,379	$25,606

(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 April 28, 2008 are summarized below.

Crude Oil:

	Daily Volumes bbls/day	WTI US$/bbl Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term					
April 1, 2008 – June 30, 2008					
Put	1,500	–	$74.00	–	–
Swap	1,000	–	–	–	$ 92.61
Swap	500	–	–	–	$ 94.30
Costless Collar(3)	400	$ 79.00	$70.00	–	–
April 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(1)	700	–	$86.10	–	–
Swap	750	–	–	–	$ 72.94
Swap	750	–	–	–	$ 74.00
Swap	750	–	–	–	$ 73.80
Swap	750	–	–	–	$ 73.35
Swap(3)	400	–	–	–	$ 78.53
July 1, 2008 – December 31, 2008					
Put Spread	1,500	–	$78.00	$58.00	–
Swap	1,500	–	–	–	$ 92.00
Swap(3)	400	–	–	–	$ 84.60
January 1, 2009 – December 31, 2009					
Collar(1)	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(1)	500	–	$92.00	$79.00	–
Put Spread(2)	500	–	$92.00	$79.00	–
Swap(1)	500	–	–	–	$100.05

(1) Financial contracts entered into during the first quarter of 2008.
(2) Financial contracts entered into subsequent to March 31, 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					
April 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(1)	11.4	$ 8.65	$ 7.60	–	–
Collar(1)	2.8	$ 8.65	$ 7.49	–	–
Collar(1)	2.8	$ 8.86	$ 7.91	–	–
Collar(1)	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(1)	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(1)(3)	14.2	–	–	–	$ 7.17
Swap(1)	2.8	–	–	–	$ 7.91
Swap(1)	2.8	–	–	–	$ 7.87
Swap(1)	2.8	–	–	–	$ 8.44
Swap(1)	2.8	–	–	–	$ 8.49
Swap(1)	5.7	–	–	–	$ 8.76
November 1, 2008 – March 31, 2009					
Collar(1)	5.7	$ 9.50	$ 8.44	–	–
3-Way option	5.7	$10.71	$ 7.91	$ 5.80	–
3-Way option(1)	1.9	$10.55	$ 8.44	$ 6.33	–
3-Way option(1)	5.7	$10.71	$ 8.44	$ 6.33	–
3-Way option(1)	9.5	$12.45	$ 8.97	$ 7.39	–
3-Way option(2)	4.7	$12.45	$ 8.97	$ 7.39	–
Put Spread(1)	4.7	–	$ 8.97	$ 7.39	–
Put Spread(2)	4.7	–	$ 8.97	$ 7.39	–
Swap(1)	2.8	–	–	–	$ 9.42
Swap(1)	2.8	–	–	–	$ 9.28
Swap(1)	2.8	–	–	–	$ 9.34
April 1, 2009 – October 31, 2009					
Swap(1)	3.8	–	–	–	$ 7.86
2008 - 2010					
Physical (escalated pricing)	2.0	–	–	–	$ 2.59

(1) Financial contracts entered into during the first quarter of 2008.
(2) Financial contracts entered into subsequent to March 31, 2008.
(3) Acquired through the acquisition of Focus.

The following sensitivities show the impact to after-tax net income for the period ended March 31, 2008 of the respective changes in forward crude oil and natural gas prices as at March 31, 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	$49,250	$(64,532)
Natural gas derivative contracts	$34,170	$(42,928)

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 April 22, 2008 are summarized below.

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

The Fund did not enter into any new electricity contracts in the first quarter of 2008.

Currency Risk

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

Cross Currency Interest Rate Swap ("CCIRS")

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

Foreign Exchange Swaps

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

The following sensitivities show the impact to after-tax net income for the period ended March 31, 2008 of the respective changes in the period end and applicable forward foreign exchange rates as at March 31, 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	$(7,093)	$7,093

($ 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	$ 107	$ (107)
Cross currency interest rate swap[(1)]	$6,755	$(6,755)

(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 $75,000,000 of notional debt at rates varying from 4.10% 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 January 2012.

If interest rates change by 1%, either lower or higher, on our variable rate debt outstanding at March 31, 2008 with all other variables held constant, the Fund's after-tax net income for a quarter would change by $1,850,000.

The following sensitivities show the impact to after-tax net income for the period ended March 31, 2008 of the respective changes in the applicable forward interest rates as at March 31, 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	$ (332)	$ 332
Cross currency interest rate swap[(1)]	$2,701	$(2,701)

(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 March 31, 2008 our ten largest counterparties, the majority of whom are investment grade, represent approximately 70% of our total accounts receivable balance. This level of credit concentration is typical of oil and gas companies of our size producing in similar regions.

At March 31, 2008 approximately $11,200,000 or 4.5% 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 March 31, 2008 is $2,800,000. The Fund did not provide for any additional doubtful accounts nor were any accounts written off during the first 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's 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 proportion 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 March 31, 2008 the debt to cash flow ratio was 1.0x including the 12 months of trailing cash flow from Focus (March 31, 2007 – 0.8x). Enerplus' bank credit facilities and senior debenture covenants carry a maximum debt-to-cash flow ratio of 3.0x including cash flow from acquisitions on a proforma basis. Traditionally Enerplus has managed its debt levels such that the debt-to-cash flow ratio has been below 1.5x, which has provided flexibility in pursuing acquisitions and capital projects. Enerplus' five-year history of debt to cash flow is illustrated below:

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

At March 31, 2008 Enerplus had additional borrowing capacity of $539,137,000 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 only 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 the past 31 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 creditor's 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 has recently been successful at increasing its bank credit facility from $1 billion to $1.4 billion despite the turmoil in the banking sector caused by subprime lending problems. 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.

Enerplus also routinely disposes of non-core assets, and uses the proceeds to repay debt. At the present time, Enerplus is exploring strategic alternatives with respect to its Joslyn oil sands lease. If the disposition is successful for all or part of the interest in Joslyn, the proceeds 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 March 31, 2008:

		Payments Due by Period					Total Committed
($ thousands)	Total	2008	2009	2010	2011	2012	after 2013
Accounts Payable	$ 355,464[(1)]	$355,464	$ –	$ –	$ –	$ –	$ –
Distributions payable to unitholders	68,939[(2)]	68,939	–	–	–	–	–
Bank credit facility	860,863	–	–	860,863	–	–	–
Senior unsecured notes	323,408[(3)]	–	–	53,666	64,682	64,682	140,378
Total commitments	$1,608,674	$424,403	$ –	$914,529	$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.

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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
(13) Ex-Officio member of Corporate Governance & Nominating Committee and Health, Safety & Environment Committee

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Executive Vice President & Chief Operating Officer

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Senior Vice President, Business Development

Robert J. Waters
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Jo-Anne M. Caza
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Rodney D. Gray
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Lyonel G. Kawa
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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.

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GLJ Petroleum Consultants
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DeGolyer and MacNaughton
Dallas, Texas

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ABBREVIATIONS

AECO	Alberta Energy Company interconnect with the Nova Gas System, the Canadian benchmark for natural gas pricing purposes
bbl(s)/day	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
BOE(s)/day	barrel of oil equivalent per day (6 Mcf of gas:1 BOE)
CBM	coalbed methane, otherwise known as natural gas from coal – NGC
GAAP	Generally accepted accounting principles
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf/day	thousand cubic feet per day
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf/day	million cubic feet per day
MWh	Megawatt hour(s) of electricity
NGLs	natural gas liquids
NYSE	New York Stock Exchange
SAGD	steam assisted gravity drainage
SEDAR	System for Electronic Document Analysis and Retrieval
TSX	Toronto Stock Exchange
WI	percentage working interest ownership
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing purposes

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