THE ENERGY OF
enerPLUS

First Quarter Report

THREE MONTHS ENDED MARCH 31, 2009

SELECTED FINANCIAL RESULTS

For the three months ended March 31,	2009	2008
Financial (000's)		
Cash Flow from Operating Activities	**$ 169,388**	$ 256,216
Cash Distributions to Unitholders[1]	**89,537**	192,358
Cash Withheld for Acquisitions and Capital Expenditures	**79,851**	63,858
Net Income	**51,786**	121,394
Debt Outstanding (net of cash)	**739,170**	1,097,821
Development Capital Spending	**99,243**	126,262
Acquisitions	**1,977**	1,765,069
Divestments	**13**	2,122
Actual Cash Distributions paid to Unitholders	**$ 0.61**	$ 1.26
Financial per Weighted Average Trust Units[2]		
Cash Flow from Operating Activities	**$ 1.02**	$ 1.74
Cash Distributions per Unit[1]	**0.54**	1.30
Cash Withheld for Acquisitions and Capital Expenditures	**0.48**	0.44
Net Income	**0.31**	0.82
Payout Ratio[3]	**53%**	75%
Adjusted Payout Ratio[3]	**112%**	125%
Selected Financial Results per BOE[4]		
Oil & Gas Sales[5]	**$ 35.24**	$ 62.10
Royalties	**(6.43)**	(11.57)
Commodity Derivative Instruments	**5.38**	(1.35)
Operating Costs	**(9.95)**	(8.96)
General and Administrative	**(2.05)**	(1.85)
Interest and Other Income and Foreign Exchange	**(0.91)**	(0.84)
Taxes	**(0.10)**	(1.18)
Asset retirement obligations settled	**(0.43)**	(0.50)
Cash Flow from Operating Activities before changes in non-cash working capital	**$ 20.75**	$ 35.85
Weighted Average Number of Trust Units Outstanding Including Equivalent Exchangeable Partnership Units (thousands)	**165,716**	147,482
Debt/Trailing 12 Month Cash Flow Ratio[6]	**0.6x**	1.0x

SELECTED OPERATING RESULTS

For the three months ended March 31,	2009	2008
Average Daily Production		
Natural gas (Mcf/day)	**338,857**	307,746
Crude oil (bbls/day)	**34,427**	33,256
Natural gas liquids (bbls/day)	**4,059**	4,603
Total daily sales (BOE/day)	**94,962**	89,150
% Natural gas	**59%**	58%
Average Selling Price(5)		
Natural gas (per Mcf)	**$ 5.13**	$ 7.52
Crude oil (per bbl)	**42.41**	86.02
NGLs (per bbl)	**40.59**	69.75
CDN$/US$ exchange rate	**0.80**	1.00
Net Wells drilled	**123**	125
Success Rate(7)	**99%**	100%

(1) Calculated based on distributions paid or payable.
(2) Based on weighted average trust units outstanding for the period, including exchangeable partnership units.
(3) Payout ratio is calculated as cash distributions to unitholders divided by cash flow from operating activities. Adjusted payout ratio is calculated as cash distributions to unitholders plus development capital and office expenditures divided by cash flow from operating activities. See "Non-GAAP Measures" in the following Management's Discussion and Analysis.
(4) Non-cash amounts have been excluded.
(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(6) Including the trailing 12 month cash flow of Focus Energy Trust for 2008.
(7) Based on wells drilled and cased.

Trust Unit Trading Summary for the three months ended March 31, 2009		**TSX – ERF.un (CDN$)**		**NYSE – ERF (US$)**
High	$	28.00	$	23.65
Low	$	16.75	$	12.85
Close	$	20.80	$	16.37

2009 Cash Distributions Per Trust Unit **Payment Month**		**CDN$**		**US$**
January	$	0.25	$	0.20
February		0.18		0.14
March		0.18		0.15
First Quarter Total	**$**	**0.61**	**$**	**0.49**

This interim report contains certain forward-looking information and statements. We refer you to the end of the accompanying Management Discussion and Analysis for our disclaimer on forward-looking information and statements which applies to all other portions of this interim report. For information on the use of the term "BOE" see "Information Regarding Disclosure in this News Release and Oil and Gas Reserves, Resources and Operational Information" at the conclusion of this news release.

PRESIDENT'S MESSAGE

Although the first quarter of 2009 was a continuation of one of the most economically challenging times in recent history, I am pleased to report that our operating and financial results were in line with expectations. We continue to enjoy the benefits of one of the strongest balance sheets in our sector, allowing us to remain focused on our operations and our plans to improve our overall business. We are on target with our production volumes, development capital spending, operating and general and administrative costs.

Production in the quarter averaged approximately 95,000 BOE/day, 7% higher than the first quarter of 2008 and in line with our expectations. As a result of reduced capital spending in 2009, we are expecting production volumes to be lower throughout the remainder of the year. We continue to anticipate average daily production volumes of 91,000 BOE/day with an exit rate of approximately 88,000 BOE/day based upon development capital spending of $300 million.

The significant drop in commodity prices has directly impacted our operations. Although we experienced a colder than normal winter across most of North America, the cumulative effect of industrial demand destruction due to the weak economy and substantially higher U.S. domestic natural gas production left the continent awash in supply, driving natural gas prices substantially lower both in the U.S. and Canada. We realized an average selling price of $5.13/Mcf for our natural gas, a 32% decrease from the first quarter of 2008. Our crude oil production realized an average price of $42.41/bbl, down over 50% from the first quarter of 2008. West Texas Intermediate crude oil prices continued to fall, reaching a low of US$33.98 early in the quarter, before stabilizing near US$50.00 by the end of March due to the effects of the OPEC production cuts and generally tighter supply. However, crude oil storage levels remain at or near record levels. Our risk management program helped protect us from the full effects of the weaker prices for the quarter. We realized cash gains of $14.3 million on our natural gas hedges and $31.6 million on our crude oil hedges. We hold downside protection on approximately 27% of our crude oil production for the remainder of the year at an effective price of over US$93.00/bbl, and approximately 26% downside protection on our natural gas production at an effective price of over $7.50/Mcf based on current forward market prices.

As a result of lower commodity prices, cash flow from operations during the quarter was $169.4 million, 34% lower than during the same period last year. In conjunction with the drop in prices and cash flows, we reduced our monthly cash distributions to unitholders in February to $0.18/unit in order to preserve our financial flexibility. Approximately 53% of our cash flow was distributed to unitholders during the quarter versus 75% last year. We continued to invest in our asset base with approximately $99 million spent on development drilling and optimization activities during the quarter. When we combine this spending with cash distributions paid to unitholders, our adjusted payout ratio was 112% or 107% before adjustments for working capital. Our balance sheet remains very strong with a debt to 12 month trailing cash flow of 0.6x.

2009 Production and Development Activity

As at March 31, 2009 Play Type	Production Volumes (BOE/day)	Capital Spending ($millions)	Wells Drilled Gross	Wells Drilled Net
Shallow Gas	24,411	29.2	117	103
Crude Oil Waterfloods	16,166	8.3	2	1
Tight Gas	15,387	29.1	20	11
Bakken Oil/Tight Oil	10,794	11.1	1	1
Other Conventional Oil & Gas	28,204	13.2	30	7
Total Conventional	**94,962**	**90.9**	**170**	**123**
Oil Sands	**–**	**8.3**	**–**	**–**
Total	**94,962**	**99.2**	**170**	**123**

Our development capital program in the first quarter was primarily focused on our natural gas assets and accounted for close to 75% of our conventional development spending. We drilled 123 net wells with a 99% success rate this quarter with approximately 84% of our capital spent on operated properties. Our capital spending program will remain sensitive to the current pricing environment, and if we continue to see weak natural gas prices we may shift more of our capital program into oil projects throughout the remainder of the year.

Tommy Lakes received the majority of the capital spent in the quarter in our tight gas resource play. Tommy Lakes is a winter access only property in northeastern British Columbia and we completed our 14 well winter drilling program including the successful drilling of our first horizontal well on these lands. We are evaluating the results of the horizontal drilling to determine what additional opportunities may exist in this area. We also drilled 103 net wells on our shallow gas resource play properties in the first quarter, with the majority of this capital focused at Shackleton where we drilled 49 wells and tied in 80. The remainder of our capital was spent between our Sleeping Giant Bakken oil play in the U.S., our crude oil waterflood resource plays and other conventional assets in Canada.

On April 17, 2009 we announced the deferral of our Kirby Oil Sands project. While we believe there is long-term value in the Kirby project, the current cost structures, commodity price environment and our cost of capital do not offer a sufficient economic return for additional investment at this time. We plan to complete an updated resource assessment this summer based on new data resulting from our seismic program which began in late 2008 and to complete the regulatory application process by this fall as originally planned. We will not, however, continue the advance engineering work which would have led to a sanctioning decision later in 2009. As we had already significantly reduced our spending plans on Kirby for 2009 to $25 million, we only expect a modest decrease in the order of $5 million this year. We expect to redeploy this capital into our growth budget, focusing on tight oil and tight gas development opportunities. We will continue to monitor economic, regulatory, market and technical developments which impact oil sands development and will revisit our plans for Kirby as circumstances warrant.

2009 Strategic Focus

Our strategic focus for this year has not changed. We are fortunate to possess one of the strongest balance sheets in our sector, affording us the flexibility to pursue acquisitions in tight gas and tight oil. The continued deterioration of the North American economy and reduced access to credit has resulted in an increase in assets for sale. However, there still remains some disparity between buyers and sellers expectations. In addition, we continue to assess our portfolio of assets to identify those that may not be core to our long-term business strategy and would look to sell these assets at the appropriate time.

We are also working on our plans to convert to a corporation with the implementation of the SIFT tax beginning in 2011. We continue to believe there is value in keeping our trust structure and preserving our tax pools during the exemption period. Converting to a corporation would be a change in our legal structure only and would not change our business strategy. Our assets are well-suited to a distribution-oriented business model and we continue to expect a significant portion of our cash flow will be paid directly to our investors if we were to convert to a corporation.

Finally, we are committed to managing our business prudently and responsibly in these difficult economic times. We are continually reviewing our operations for ways to improve our business and drive efficiencies throughout our organization. We are also carefully monitoring both our development capital spending and our distribution levels to ensure that we are minimizing any increases in debt and preserving our balance sheet for acquisition opportunities. Our experience has shown that opportunities arise in times of uncertainty. We have a proven track record of acquiring quality assets at opportune times and we expect to be able to utilize our financial strength and skills to position ourselves to add assets that will continue to sustain our business model.

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

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

The following discussion and analysis of financial results is dated May 7, 2009 and is to be read in conjunction with:

- the audited consolidated financial statements as at and for the years ended December 31, 2008 and 2007; and
- the unaudited interim consolidated financial statements as at and for the three months ended March 31, 2009 and 2008.

All amounts are stated in Canadian dollars unless otherwise specified. All references to GAAP refer to Canadian generally accepted accounting principles. All note references relate to the notes included with the consolidated financial statements. In accordance with Canadian practice, revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise stated. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading. For the meanings of certain terms and abbreviations used herein, see "Abbreviations" at the end of this interim report.

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

OVERVIEW

Our first quarter operating results were in-line with expectations with production averaging 94,962 BOE/day, operating expenses of $9.84/BOE and development capital spending of $99.2 million. Despite increased production levels, cash flow from operating activities decreased 34% to $169.4 million compared to the first quarter of 2008 due to lower realized crude oil and natural gas prices. As a result of lower commodity price levels our price risk management program generated cash gains of $45.9 million and non-cash gains of $12.7 million.

We continue to focus on cost control across all areas of our organization, including our development capital spending, operating expenses and general & administrative expenses. Our 2009 development capital program is still anticipated to total $300 million however we are closely evaluating all projects and may look to shift some spending from gas to oil projects if natural gas prices remain at current levels. On April 17, 2009 we announced that we are deferring further development of our Kirby oil sands project as current cost structures, the commodity price environment and our cost of capital do not offer a sufficient return for this project at this time.

At March 31, 2009 we continue to have a conservative balance sheet with over $950 million of available credit capacity and a debt to 12 month trailing cash flow ratio of 0.6x. We believe we are well positioned to capitalize on potential acquisition opportunities given our track record of strategic acquisitions and the strength of our balance sheet.

RESULTS OF OPERATIONS

Production

Production in the first quarter of 2009 was in-line with our expectations averaging 94,962 BOE/day, an increase of 7% from 89,150 BOE/day in the first quarter of 2008. This increase reflects a full quarter of production from the Focus assets that were acquired in February 2008 along with incremental production from the 2008 winter drilling program at Tommy Lakes.

Average production volumes for the three months ended March 31, 2009 and 2008 are outlined below:

	Three months ended March 31,		
Daily Production Volumes	**2009**	**2008**	**% Change**
Natural gas (Mcf/day)	**338,857**	307,746	10%
Crude oil (bbls/day)	**34,427**	33,256	4%
Natural gas liquids (bbls/day)	**4,059**	4,603	(12%)
Total daily sales (BOE/day)	**94,962**	89,150	7%

We continue to expect production to decline through 2009 as a result of our reduced capital spending and are maintaining our guidance of annual average production of 91,000 BOE/day and exit rate of 88,000 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, 2009 and 2008. It also compares the benchmark price indices for the same periods.

	Three months ended March 31,		
Average Selling Price[1]	**2009**	**2008**	**% Change**
Natural gas (per Mcf)	**$ 5.13**	$ 7.52	(32%)
Crude oil (per bbl)	**42.41**	86.02	(51%)
Natural gas liquids (per bbl)	**40.59**	69.75	(42%)
Per BOE	**35.24**	62.09	(43%)

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

	Three months ended March 31,		
Average Benchmark Pricing	**2009**	**2008**	**% Change**
AECO natural gas – monthly index (CDN$/Mcf)	**$ 5.63**	$ 7.13	(21%)
AECO natural gas – daily index (CDN$/Mcf)	**4.92**	7.90	(38%)
NYMEX natural gas – monthly NX3 index (US$/Mcf)	**4.79**	8.07	(41%)
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	**5.99**	8.07	(26%)
WTI crude oil (US$/bbl)	**43.08**	97.92	(56%)
WTI crude oil: CDN$ equivalent (CDN$/bbl)	**53.85**	97.92	(45%)
CDN$/US$ exchange rate	**0.80**	1.00	(20%)

Natural gas prices continued to drop during the first quarter. Winter weather this year was colder than normal across most of North America and imports of LNG into the U.S. remained low. However, the combination of demand destruction from the weak economy and continued over-supply from U.S. domestic natural gas production led to continued downward pressure on price throughout the first quarter of 2009.

We realized an average price on our natural gas of $5.13/Mcf (net of transportation costs) during the first quarter of 2009, a decrease of 32% from $7.52/Mcf for the same period in 2008. The majority of our natural gas sales are priced with reference to the monthly and daily

AECO indices. The decrease in our realized natural gas price during the first quarter is comparable to the average change in the combined indices.

West Texas Intermediate ("WTI") crude oil prices stabilized in the first quarter of 2009 after falling dramatically in the previous quarter. During the quarter WTI prices fluctuated between US$33.98/bbl and US$54.34/bbl and closed the quarter at US$49.66/bbl. Key drivers supporting crude oil prices at this level are a reduction in OPEC supply, falling rig counts and a long term demand outlook which has resulted in a strong forward market. However, current fundamentals show crude oil storage at historically high levels with continuing weak global demand.

The average price we received for our crude oil during the first quarter of 2009 decreased 51% to $42.41/bbl (net of transportation costs) from $86.02/bbl during the same period in 2008. In comparison, the WTI crude oil benchmark price, in Canadian dollars, decreased 45% from the corresponding period in 2008. The difference between the change in the benchmark and our average price can be attributed to our light sweet oil produced in the U.S. and the light/medium blends in Canada, both of which were subject to wider price differentials due to reduced refinery demand for lighter crudes.

The Canadian dollar averaged $0.80 per U.S. dollar during the first quarter of 2009 versus being near par during the first quarter of 2008. As most of our crude oil and a portion of our natural gas is priced in reference to U.S. dollar denominated benchmarks, this movement in the exchange rate helped offset, in part, the decrease in prices we realized overall.

Price Risk Management

We continue to adjust our price risk management program with consideration given to our overall financial position together with the economics of our development capital program and potential acquisitions. Consideration is also given to the upfront and potential costs of our risk management program as we seek to limit our exposure to price downturns. Hedge positions for any given term are transacted across a range of prices and time. We did not enter into any new natural gas or crude oil contracts during the first quarter of 2009.

Our existing commodity contracts are designed to protect a portion of our natural gas sales through October 2010 and a portion of our crude oil sales through December 2009. We have also hedged a portion of our electricity consumption through December 2010 to protect against rising electricity costs in the Alberta power market. See Note 8 for a detailed list of our current price risk management positions.

The following is a summary of the financial contracts in place at April 29, 2009 expressed as a percentage of our anticipated net production volumes:

	Natural Gas (CDN$/Mcf)			Crude Oil (US$/bbl)
	April 1, 2009 – October 31, 2009	November 1, 2009 – March 31, 2010	April 1, 2010 – October 31, 2010	April 1, 2009 – December 31, 2009
Purchased Puts (floor prices)	$ 8.30	$ 8.99	$ –	$ 98.08
%	18%	9%	–	25%
Sold Puts (limiting downside protection)	$ 7.85	$ –	$ –	$ 66.17
%	4%	–	–	11%
Swaps (fixed price)	$ 7.41	$ 7.33	$ 7.33	$ 100.05
%	11%	10%	9%	2%
Sold Calls (capped price)	$ –	$ 12.13	$ –	$ 92.98
%	–	2%	–	11%

Based on weighted average price (before premiums), estimated average annual production of 91,000 BOE/day and assuming an 18% royalty rate.

Accounting for Price Risk Management

During the first quarter of 2009 our commodity price risk management program generated cash gains of $14.3 million on our natural gas contracts and $31.6 million on our crude oil contracts. These gains are due to contracts in place that provided floor protection that was above market prices. In comparison, our commodity price risk management program resulted in cash gains of $4.3 million on our natural gas contracts and cash losses of $15.2 million on our crude oil contracts in the first quarter of 2008.

At March 31, 2009 the fair value of our natural gas and crude oil derivative instruments, net of premiums, represented gains of $57.3 million and $76.3 million respectively. These gains are recorded as current deferred financial assets on our balance sheet. In comparison, at December 31, 2008 the fair value of our natural gas and crude oil derivative instruments represented gains of $24.3 million and $96.6 million respectively, which were also recorded as current deferred financial assets on our balance sheet. The change in the fair value of our commodity derivative instruments during the quarter resulted in an unrealized gain of $33.0 million for natural gas and an unrealized loss of $20.3 million for crude oil. As the forward markets for natural gas and crude oil fluctuate, new contracts are executed and existing contracts are realized, changes in fair value are reflected as a non-cash charge or non-cash gain in earnings. See Note 8 for details.

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

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	**Three months ended March 31, 2009**				Three months ended March 31, 2008			
Cash gains/(losses):								
Natural Gas	**$**	**14.3**	**$**	**0.47/Mcf**	$	4.3	$	0.15/Mcf
Crude Oil		**31.6**	**$**	**10.21/bbl**		(15.2)	$	(5.03)/bbl
Total Cash gains/(losses)	**$**	**45.9**	**$**	**5.38/BOE**	$	(10.9)	$	(1.35)/BOE
Non-cash gains/(losses) on financial contracts:								
Change in fair value – natural gas	**$**	**33.0**	**$**	**1.08/Mcf**	$	(58.3)	$	(2.08)/Mcf
Change in fair value – crude oil		**(20.3)**	**$**	**(6.56)/bbl**		(21.1)	$	(6.98)/bbl
Total non-cash gains/(losses)	**$**	**12.7**	**$**	**1.48/BOE**	$	(79.4)	$	(9.79)/BOE
Total gains/(losses)	**$**	**58.6**	**$**	**6.86/BOE**	$	(90.3)	$	(11.14)/BOE

Revenues

Crude oil and natural gas revenues in the first quarter of 2009 were $301.2 million ($307.5 million, net of $6.3 million of transportation costs), a decrease of 40% or $202.5 million compared to $503.7 million ($510.0 million, net of $6.3 million of transportation costs) in the first quarter 2008. Although production was higher in the first quarter of 2009, the significant decrease in commodity prices resulted in lower overall revenues.

Analysis of Sales Revenue[(1)] ($ millions)		**Crude oil**		**NGLs**		**Natural Gas**		**Total**
Quarter ended March 31, 2008	$	260.3	$	29.2	$	214.2	$	503.7
Price variance[(1)]		(135.1)		(10.6)		(77.9)		(223.6)
Volume variance		6.2		(3.8)		18.7		21.1
Quarter ended March 31, 2009	**$**	**131.4**	**$**	**14.8**	**$**	**155.0**	**$**	**301.2**

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

Other Income

Other income for the first quarter of 2009 was $0.1 million compared to $15.1 million for the first quarter of 2008. 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 business interruption insurance proceeds of $6.4 million related to the Giltedge fire.

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three months ended March 31, 2009 and 2008, royalties were $55.0 million and $93.8 million, representing approximately 18% and 19% of oil and gas sales, net of transportation costs, respectively.

On January 1, 2009 a new royalty regime came into effect in the province of Alberta where approximately 60% of our production is located. This new regime has provisions for escalating royalty rates depending on production and product price levels. The Alberta government modified the new regime with programs to encourage the drilling of medium and deeper wells and on March 3, 2009, announced a short-term incentive program to further encourage the drilling of new wells over the next 12 months. With our reduced 2009 development capital spending plans we do not expect any material impact from these incentive programs.

Operating Expenses

Operating expenses for the first quarter of 2009 were in-line with expectations at $9.84/BOE or $84.1 million, compared to $8.88/BOE or $72.0 million for the same period in 2008. The increase is mainly due to additional spending to meet regulatory requirements and higher repairs and maintenance charges. Excluding non-cash gains related to our electricity swaps, operating costs were $9.95/BOE compared to $8.96/BOE in the first quarter of 2008. We are continuing to focus our efforts on reducing our operating costs.

We are maintaining our annual guidance for operating costs of approximately $10.65/BOE which includes an expectation of costs savings but also reflects expected production declines during the year.

General and Administrative Expenses ("G&A")

During the first quarter of 2009 G&A expenses increased 9% to $2.21/BOE or $18.9 million compared to $2.03/BOE or $16.4 million in the first quarter of 2008. The year-over-year increase was primarily due to higher compensation costs associated with the increased number of employees along with increased office space. G&A for the quarter was in line with expectations and on a BOE basis we expect it will increase during the year as our production is anticipated to decline. We are maintaining our guidance for G&A expenses at $2.45/BOE, which includes non-cash G&A costs of approximately $0.20/BOE.

During the quarter our G&A expenses included non-cash charges for our trust unit rights incentive plan of $1.4 million or $0.16/BOE compared to $1.5 million or $0.18/BOE for 2008. These amounts relate solely to our trust unit rights incentive plan and are determined using a binomial lattice option-pricing model. See Note 7 for further details.

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

	Three months ended March 31,	
General and Administrative Costs ($ millions)	**2009**	**2008**
Cash	**$ 17.5**	$ 14.9
Trust unit rights incentive plan (non-cash)	**1.4**	1.5
Total G&A	**$ 18.9**	$ 16.4

(Per BOE)	**2009**	**2008**
Cash	**$ 2.05**	$ 1.85
Trust unit rights incentive plan (non-cash)	**0.16**	0.18
Total G&A	**$ 2.21**	$ 2.03

Interest Expense

Interest expense includes interest on long-term debt, the premium amortization on our US$175 million senior unsecured notes, unrealized gains and losses resulting from the change in fair value of our interest rate swaps as well as the interest component on our cross currency interest rate swap ("CCIRS"). See Note 5 for further details.

Interest on long-term debt for the three months ended March 31, 2009 totaled $5.6 million, a $7.7 million decrease from $13.3 million during the same quarter of 2008. The decrease is due to lower average indebtedness and a lower average interest rate of 2.3% during the first three months of 2009 compared to 4.3% in the same period in 2008.

For the three months ended March 31, 2009 we recorded unrealized losses of $6.4 million compared to gains of $6.3 million in 2008. The changes in the fair value of our interest rate swaps and CCIRS that result from movements in forward market interest rates cause non-cash interest to fluctuate between periods.

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

	Three months ended March 31,	
Interest Expense ($ millions)	**2009**	**2008**
Interest on long-term debt	**$ 5.6**	$ 13.3
Unrealized loss/(gain)	**6.4**	(6.3)
Total Interest Expense	**$ 12.0**	$ 7.0

At March 31, 2009 approximately 25% of our debt was based on fixed interest rates while 75% had floating interest rates. In comparison, at March 31, 2008 approximately 12% of our debt was based on fixed interest rates and 88% was based on floating interest rates.

Capital Expenditures

During the first quarter of 2009 we spent $99.2 million on development capital which was in line with our expectations. These expenditures included the completion and tie-in of shallow natural gas wells drilled in the fourth quarter of 2008 at Bantry, Verger and Shackleton, as well as the successful completion of our winter drilling program at Tommy Lakes. In 2009 we have achieved a 99% success rate with our drilling program on 123 net wells.

Property acquisitions during the three months ended March 31, 2009 were $2.0 million compared to $7.5 million during the three months ended March 31, 2008. Corporate acquisitions for the first quarter of 2008 totaled approximately $1.7 billion and represented the Focus acquisition which closed on February 13, 2008.

Total net capital expenditures for the first quarter of 2009 and 2008 are outlined below:

	Three months ended March 31,	
Capital Expenditures ($ millions)	**2009**	**2008**
Development expenditures	**$ 79.2**	$ 109.3
Plant and facilities	**20.0**	17.0
Development Capital	**99.2**	126.3
Office	**0.6**	1.6
Sub-total	**99.8**	127.9
Acquisitions of oil and gas properties(1)	**2.0**	7.5
Corporate acquisitions	**–**	1,757.5
Dispositions of oil and gas properties(1)	**–**	(2.1)
Total Net Capital Expenditures	**$ 101.8**	$ 1,890.8
Total Capital Expenditures financed with cash flow	**$ 79.9**	$ 63.9
Total Capital Expenditures financed with debt and equity	**21.9**	1,826.9
Total Net Capital Expenditures	**$ 101.8**	$ 1,890.8

(1) Net of post-closing adjustments.

We are maintaining our 2009 guidance of $300 million for annual development capital spending, however we may direct more of our spending to oil projects should natural gas prices remain at current levels.

Oil Sands

Our current oil sands portfolio includes the 100% owned and operated Kirby steam assisted gravity drainage ("SAGD") project and a 12% minority equity ownership interest in Laricina Energy Ltd., a private oil sands company focused on SAGD development in the Athabasca oil sands.

On April 17, 2009 we announced we are deferring further development of the Kirby oil sands project. Several key activities will be completed in order to wrap up current efforts and position the project such that it could be efficiently reinitiated at a later date. Our original 2009 activities were directed at providing additional information to regulators and stakeholders to advance our application, completing a seismic program which began in late 2008 and advancing detailed engineering. We plan to complete an updated resource assessment this summer based on new seismic data and to complete the regulatory application process by this fall as originally planned. We will not, however, continue the advance engineering work which would have led to a sanctioning decision later in 2009. We now expect our spending on Kirby for 2009 to total approximately $20 million, compared to our original guidance of $25 million.

Since inception the capitalized costs related to our oil sands projects are $266.7 million. As these projects have not commenced commercial production, all associated costs inclusive of acquisition expenditures are capitalized and excluded from our depletion calculation.

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, 2009 DDA&A increased to $162.6 million or $19.02/BOE compared to $139.8 million or $17.23/BOE during the same period in 2008. The increase is primarily due to a full quarter of Focus production in 2009.

No impairment of the Fund's assets existed at March 31, 2009 using year-end reserves updated for development activity and management's estimates of future prices.

Goodwill

The goodwill balance of $639.3 million arose as a result of previous corporate acquisitions and represents the excess of the total purchase price over the fair value of the net identifiable assets and liabilities acquired.

Accounting standards require the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate the balance might be impaired. If such impairment exists, it would be charged to income in the period in which the impairment occurs. No goodwill impairment existed as at March 31, 2009.

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 $211.2 million at March 31, 2009 compared to $207.4 million at December 31, 2008.

The following table compares the amortization and accretion of the asset retirement obligation and actual asset retirement obligations settled during the period.

	Three months ended March 31,	
($ millions)	**2009**	**2008**
Total Amortization and Accretion of Asset Retirement Obligations	**$ 8.6**	$ 7.2
Asset Retirement Obligations Settled	**$ 3.7**	$ 4.0

The timing of actual asset retirement costs will differ from the timing of amortization and accretion charges. We expect that actual asset retirement costs will be incurred over the next 66 years with the majority between 2039 and 2048. 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 $26.1 million for the quarter ended March 31, 2009 compared to a recovery of $35.2 million for the same period in 2008. The decreased recovery in the first quarter of 2009 is mainly due to lower taxable income, partially offset by a $8.4 million recovery related to the enactment of specified investment flow through ("SIFT") legislation, as well as a reduction in the province of British Columbia's corporate income tax rate.

Current Income Taxes

In our current structure, payments are made by our crude oil and natural gas operating entities to the Fund which ultimately transfers both the income and future tax liability to our unitholders. As a result, we expect minimal cash income taxes to be paid by our Canadian operating entities. Effective January 1, 2011 we will be subject to the SIFT tax should we remain a trust. However with the enactment of legislation in March 2009 defining the provincial component of the SIFT tax, the effective tax rate for a trust will now be similar to a corporation. The legislation allowing for the conversion of a SIFT entity into a corporation on a tax deferred basis and the acceleration of the recognition of the "safe harbour" limit was also enacted in March 2009.

The amount of current taxes overall recorded throughout the year with respect to our U.S. operations is dependent upon income levels and the timing of both capital expenditures and the repatriation of funds to Canada. For the first quarter of 2009 we recorded current income taxes $0.8 million compared to $12.2 million for the same period in 2008. The decrease in current taxes is due to a decrease in net income.

Based on current commodity prices and our 2009 development capital spending plans we now expect our U.S. current income taxes to average approximately 10% of our cash flow from U.S. operations for 2009.

Net Income

Net income for the first quarter of 2009 was $51.8 million or $0.31 per trust unit compared to $121.4 million or $0.82 per trust unit for the same period in 2008. The $69.6 million decrease in net income was primarily due to a significant decline in oil and gas prices resulting in lower oil and gas sales revenue of $202.5 million (net of transportation costs), as well as increased DDA&A of $22.8 million, increased operating costs of $12.1 million and decreased future income tax recovery of $9.1 million. This was partially offset by increased commodity derivative instrument gains of $149.0 million and decreased royalties of $38.8 million.

Cash Flow from Operating Activities

Cash flow for the three months ended March 31, 2009 was $169.4 million or $1.02 per trust unit compared to $256.2 million or $1.74 per trust unit for the same period in 2008. The decrease in cash flow per unit was largely due to the significant decrease in crude oil and natural gas prices.

Selected Financial Results

Per BOE of production (6:1)	Three months ended March 31, 2009 Operating Cash Flow[(1)]	Non-Cash & Other Items	Total	Three months ended March 31, 2008 Operating Cash Flow[(1)]	Non-Cash & Other Items	Total
Production per day			94,962			89,150
Weighted average sales price[(2)]	$ 35.24	$ –	$ 35.24	$ 62.10	$ –	$ 62.10
Royalties	(6.43)	–	(6.43)	(11.57)	–	(11.57)
Commodity derivative instruments	5.38	1.48	6.86	(1.35)	(9.79)	(11.14)
Operating costs	(9.95)	0.11	(9.84)	(8.96)	0.08	(8.88)
General and administrative	(2.05)	(0.16)	(2.21)	(1.85)	(0.18)	(2.03)
Interest expense, net of other income	(0.63)	(0.76)	(1.39)	(0.79)	0.77	(0.02)
Foreign exchange gain/(loss)	(0.28)	0.18	(0.10)	(0.05)	(0.39)	(0.44)
Current income tax	(0.10)	–	(0.10)	(1.18)	–	(1.18)
Restoration and abandonment cash costs	(0.43)	0.43	–	(0.50)	0.50	–
Depletion, depreciation, amortization and accretion	–	(19.02)	(19.02)	–	(17.23)	(17.23)
Future income tax recovery	–	3.05	3.05	–	4.33	4.33
Gain on sale of marketable securities[(3)]	–	–	–	–	1.02	1.02
Total per BOE	$ 20.75	$ (14.69)	$ 6.06	$ 35.85	$ (20.89)	$ 14.96

(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, 2009 and 2008.

(CDN$ millions, except per unit amounts)	Three months ended March 31, 2009 Canada	U.S.	Total	Three months ended March 31, 2008 Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	325,799	13,058	338,857	295,799	11,947	307,746
Crude oil (bbls/day)	25,381	9,046	34,427	23,734	9,522	33,256
Natural gas liquids (bbls/day)	4,059	–	4,059	4,603	–	4,603
Total Daily Production Volumes (BOE/day)	83,740	11,222	94,962	77,637	11,513	89,150
Pricing[(1)]						
Natural gas (per Mcf)	$ 5.12	$ 5.38	$ 5.13	$ 7.47	$ 8.95	$ 7.52
Crude oil (per bbl)	43.26	40.04	42.41	84.31	90.30	86.02
Natural gas liquids (per bbl)	40.59	–	40.59	69.75	–	69.75
Capital Expenditures						
Development capital and office	$ 89.0	$ 10.8	$ 99.8	$ 108.3	$ 19.6	$ 127.9
Acquisitions of oil and gas properties	1.8	0.2	2.0	7.4	0.1	7.5
Dispositions of oil and gas properties	–	–	–	(2.1)	–	(2.1)
Revenues						
Oil and gas sales[(1)]	$ 262.3	$ 38.9	$ 301.2	$ 415.7	$ 88.0	$ 503.7
Royalties[(2)]	(46.5)	(8.5)	(55.0)	(75.2)	(18.6)	(93.8)
Commodity derivative instruments gain/(loss)	58.6	–	58.6	(90.3)	–	(90.3)
Expenses						
Operating	$ 80.3	$ 3.8	$ 84.1	$ 68.6	$ 3.4	$ 72.0
General and administrative	17.0	1.9	18.9	15.1	1.3	16.4
Depletion, depreciation, amortization and accretion	138.9	23.7	162.6	118.4	21.4	139.8
Current income taxes expense/(recovery)	–	0.8	0.8	(2.7)	12.2	9.5

(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

In general, crude oil and natural gas sales increased from 2007 to mid 2008 due to increased commodity prices and increased production from the Focus acquisition. Oil and gas sales decreased in the latter part of 2008 and in the first quarter of 2009 as a result of the sharp decline in commodity prices.

Net income has been affected by fluctuating commodity prices and risk management costs, the fluctuating Canadian dollar, higher operating costs and changes in future tax provisions due to the SIFT tax and corporate rate reductions. Furthermore, changes in the fair value of our commodity derivative instruments and other financial instruments cause net income to continually fluctuate between quarters.

Quarterly Financial Information ($ millions, except per trust unit amounts)	**Oil and Gas Sales**[1]	**Net Income**	**Net Income per trust unit** Basic	**Net Income per trust unit** Diluted
2009				
First quarter	**$ 301.2**	**$ 51.8**	**$ 0.31**	**$ 0.31**
2008				
Fourth Quarter	$ 418.3	$ 189.5	$ 1.15	$ 1.15
Third Quarter	647.8	465.8	2.82	2.82
Second Quarter	734.4	112.2	0.68	0.68
First quarter	503.7	121.4	0.82	0.82
Total	$ 2,304.2	$ 888.9	$ 5.54	$ 5.53
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

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

Liquidity and Capital Resources

Capital Markets and Enerplus' Credit Exposure

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

Credit Facility

Enerplus' bank credit facility is an unsecured, covenant-based agreement with a syndicate of thirteen financial institutions, a copy of which was filed on March 18, 2008 as a "Material document" on the Fund's SEDAR profile at www.sedar.com. Of the thirteen syndicate members in Enerplus' facility, seven are major Canadian banks which represent approximately $985 billion or 70% of the commitments under the $1.4 billion facility. The facility is extendable each year and is currently set to expire in November 2010. Borrowing costs under the facility range between 55.0 and 110.0 basis points over bankers' acceptance rates, with our current borrowing cost being 55.0 basis points over bankers' acceptance rates. At March 31, 2009 we have drawn $447.8 million or approximately 32% of the $1.4 billion facility and have a trailing debt-to-cash flow ratio of 0.6x. At March 31, 2009 we are in compliance with all covenants under the credit facility.

Our exposure to our lenders relates to their potential inability to provide funding. Should a lender be unable or choose not to fund, other lenders have the right, but not the obligation, to increase their commitment levels to cover the shortfall. Failure to fund would be considered a breach of contract and could result in potential damages in our favour, however the likelihood of substantiating and receiving damages is unknown. We have not experienced any funding issues under the facility to date.

Oil and Gas Sales Counterparties

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

Financial Derivative Counterparties

The Fund is exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. The Fund mitigates this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the majority of our financial counterparties. These agreements provide some credit protection in that they generally allow parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. Absent an ISDA we rely on long form confirmations which provide Enerplus with similar credit protection. At March 31, 2009 we had $143.2 million in mark-to-market assets offset by $24.7 million of mark-to-market liabilities consisting of net asset positions of $91.6 million with major Canadian institutions and $26.9 million with U.S. institutions.

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

Joint Venture Partners

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

Distribution Policy

The amount of cash distributions is proposed by management and approved by the Board of Directors. We continually assess distribution levels with respect to anticipated cash flows, debt levels, capital spending plans and capital market conditions. The level of cash withheld has historically varied between approximately 10% and 40% of annual cash flow from operating activities and is dependent upon numerous factors, the most significant of which are the prevailing commodity price environment, our current levels of production, debt obligations, funding requirements for our development capital program and our access to equity markets.

The sharp decrease in crude oil and natural gas prices has resulted in a decrease in our overall cash flows. This commodity price downturn, combined with the ongoing uncertainty and reduced access to the debt and equity markets, has reinforced our belief in the importance of maintaining strong financial flexibility. To that end, we have significantly reduced our monthly cash distributions to $0.18 per unit effective February 20, 2009 from a high of $0.47 per trust unit on September 20, 2008. We intend to manage our distribution levels and capital spending in order to minimize increases in our debt levels and preserve our balance sheet strength for future acquisitions.

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.

Sustainability of our Distributions and Asset Base

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

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

Enerplus currently has approximately $9.5 billion of safe harbour growth capacity within the context of the Canadian Government's "normal growth" guidelines for SIFT's.

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 2009 cash distributions of $89.5 million were funded entirely through cash flow of $169.4 million.

Our payout ratio, which is calculated as cash distributions divided by cash flow, was 53% for the first quarter of 2009 compared to 75% for the same period in 2008. The decrease in the payout ratio is mainly due to the reduction in our monthly cash distributions. Our adjusted payout ratio, which is calculated as cash distribution plus development capital and office expenditures divided by cash flow, was 112% for the first quarter of 2009. Our 2009 development capital program spending is more heavily weighted towards the first quarter as some properties such as Tommy Lakes have limited access during the year. In addition, changes in our non-cash operating working capital also increased our first quarter adjusted payout ratio. Over the remaining quarters we still expect to support our distributions and capital expenditures with our cash flow. However, we will continue to fund acquisitions and growth through additional debt and equity when required. We continue to have conservative debt levels with a trailing twelve month debt-to-cash flow ratio of 0.6x at March 31, 2009.

For the three months ended March 31, 2009, our cash distributions exceeded our net income by $37.8 million (2008 – $71.0 million). Non-cash items, such as changes in the fair value of our derivative instruments and future income taxes, cause net income to fluctuate between periods but do not impact cash flow from operations. In addition, other non-cash charges such as DDA&A are not a good proxy for the cost of maintaining our productive capacity as they are based on the historical costs of our PP&E and not the fair market value of replacing those assets within the context of the current environment.

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

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

($ millions, except per unit amounts)		Three months ended March 31, 2009		Year ended December 31, 2008		Year ended December 31, 2007
Cash flow from operating activities:	**$**	**169.4**	$	1,262.8	$	868.5
Cash distributions		**89.5**		786.1		646.8
Excess of cash flow over cash distributions	**$**	**79.9**	$	476.7	$	221.7
Net income	**$**	**51.8**	$	888.9	$	339.7
(Shortfall)/excess of net income over cash distributions	**$**	**(37.7)**	$	102.8	$	(307.1)
Cash distributions per weighted average trust unit	**$**	**0.54**	$	4.90	$	5.07
Payout ratio[1]		**53%**		62%		74%

(1) Based on cash distributions divided by cash flow.

Long-Term Debt

Long-term debt at March 31, 2009 was $739.3 million, an increase of $75.0 million from $664.3 million at December 31, 2008. Long-term debt at March 31, 2009 is comprised of $447.8 million of bank indebtedness and $291.5 million of senior unsecured notes.

Bank indebtedness of $447.8 million at March 31, 2009 increased $66.9 million from December 31, 2008. This increase is partially due to our 2009 development program being more heavily weighted towards the first quarter. In addition, we had significant development activity in the last two months of 2008 resulting in numerous payments to vendors in the first quarter of 2009. As our development capital program will moderate over the remainder of the year we do not expect to significantly increase debt to fund development activity.

Our working capital at March 31, 2009, excluding cash, current deferred financial assets and credits and future income taxes increased by $70.1 million compared to December 31, 2008. This change is due to decreased accounts payable that resulted from lower capital spending activity along with decreased distributions payable as a result of the reduction in our monthly distributions.

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

Financial Leverage and Coverage	March 31, 2009	December 31, 2008
Long-term debt to cash flow (12 month trailing)	**0.6 x**	0.5 x
Cash flow to interest expense (12 month trailing)	**40.2 x**	46.5 x
Long-term debt to long-term debt plus equity	**15%**	13%

Long-term debt is measured net of cash.

At March 31, 2009 Enerplus had a $1.4 billion unsecured covenant based facility that matures November 2010, through its wholly-owned subsidiary EnerMark Inc. We have the ability to request an extension of the facility each year or repay the entire balance at maturity. 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, 2009 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, 2008 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 4.

We anticipate that we will continue to have adequate liquidity under our bank credit facility and from cash flow from operating activities to fund planned development capital spending in 2009.

Accumulated Deficit

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

Trust Unit Information

We had 165,828,000 trust units outstanding at March 31, 2009 compared to 164,142,000 trust units at March 31, 2008 and 165,590,000 trust units outstanding at December 31, 2008. This includes 6,841,000 exchangeable partnership units which are convertible at the option of the holder into 0.425 of an Enerplus trust unit (2,907,000 trust units). During the first quarter of 2009, 397,000 partnership units were converted into 169,000 trust units.

During the first quarter of 2009, 238,000 trust units (2008 – 317,000) 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 $5.4 million (2008 – $11.9 million) of additional equity to the Fund. For further details see Note 7.

The weighted average basic number of trust units outstanding for the three months ended March 31, 2009 was 165,716,000 (2008 – 147,482,000). At April 29, 2009 we had 165,872,000 trust units outstanding including the equivalent limited partnership units.

Income Taxes

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

Canadian Unitholders

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

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

For 2009, we estimate that 95% of cash distributions will be taxable and 5% will be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon, among other things, production, commodity prices and cash flow experienced throughout the year.

U.S. Unitholders

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

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

For 2009, we estimate that 90% of cash distributions will be taxable to most U.S. investors and 10% will be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon production, commodity prices and cash flow experienced throughout the year.

In April 2009, we estimate our non-resident ownership to be 65%.

INTERNAL CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the quarter ended March 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

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

In 2006, Canada's Accounting Standards Board (AcSB) ratified a strategic plan that will result in Canadian GAAP being converged with IFRS by 2011 for public reporting entities. On February 13, 2008 the AcSB confirmed that IFRS will be required for public companies beginning January 1, 2011.

In order to meet our reporting requirements and transition to IFRS we have established a project team comprised of individuals from Finance, Information Systems and Business Solutions, Tax, Investor Relations and Management. Our transition plan consists of four main phases:

- An IFRS diagnostic phase which involves an assessment of the differences between Canadian GAAP and IFRS,
- An assessment and selection phase whereby we will determine accounting policies for transition and our continuing IFRS accounting policies,
- An evaluation of our information systems, business processes, procedures and controls to support the new reporting standards, and
- Training and development.

To date we have completed our IFRS diagnostic assessment and have started to analyze and identify accounting policy choices, which include assessing the impact on information systems and business processes. We have also provided training to certain business groups which are impacted. We intend to generate financial information in accordance with IFRS during 2010 to provide comparative information for the 2011 financial statements.

The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect our reported financial position and results of operations. As we have not yet determined our accounting policies, we are unable to quantify the impact of adopting IFRS on our financial statements. In addition, due to anticipated changes to IFRS and International Accounting Standards prior to our adoption of IFRS, our plan is subject to change based on new facts and circumstances that arise after the date of this MD&A.

Additional Information

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

This management's discussion and analysis ("MD&A") contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: the amount, timing and tax treatment of cash distributions to unitholders; payout ratios; tax treatment of income trusts such as the Fund; the structure of the Fund and its subsidiaries; the Fund's income taxes, tax liabilities and tax pools; the volume and product mix of the Fund's oil and gas production; oil and natural gas prices and the Fund's risk management programs; the amount of asset retirement obligations; future liquidity and financial capacity and resources; future capital expenditures; cost and expense estimates; results from operations and financial ratios; the Fund's on going strategy; the Fund's credit exposure; cash flow sensitivities; royalty rates and their impact on the Fund's operations and results; future growth including development, exploration, and acquisition and development activities and related expenditures, including with respect to both our conventional and oil sands activities.

The forward-looking information and statements contained in this MD&A reflect several material factors and expectations and assumptions of the Fund including, without limitation: that the Fund will continue to conduct its operations in a manner consistent with past operations; the general continuance of current or, where applicable, assumed industry conditions; availability of debt and/or equity sources to fund the Fund's capital and operating requirements as needed; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; the accuracy of the estimates of the Fund's reserve volumes; and certain commodity price and other cost assumptions. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable at this time but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; unanticipated operating results or production declines; changes in tax or environmental laws or royalty rates; increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserves volumes; limited, unfavourable or no access to debt or equity capital markets; increased costs and expenses; the impact of competitors; reliance on industry partners; and certain other risks detailed from time to time in the Fund's public disclosure documents including, without limitation, those risks identified in this MD&A, our MD&A for the year ended December 31, 2008 and in the Fund's Annual Information Form for the year ended December 31, 2008, copies of which are available on the Fund's SEDAR profile at www.sedar.com and which also form part of the Fund's Form 40-F for the year ended December 31, 2008 filed with the SEC, a copy of which is available at www.sec.gov.

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

Consolidated Balance Sheets

(CDN$ thousands) (Unaudited)	March 31, 2009	December 31, 2008
Assets		
Current assets		
Cash	**$ 125**	$ 6,922
Accounts receivable	**144,893**	163,152
Deferred financial assets *(Note 8)*	**134,898**	121,281
Other current	**5,955**	3,783
	285,871	295,138
Property, plant and equipment *(Note 2)*	**5,213,631**	5,246,998
Goodwill	**639,340**	634,023
Deferred financial assets *(Note 8)*	**8,288**	6,857
Other assets *(Note 8)*	**47,116**	47,116
	$ 6,194,246	$ 6,230,132
Liabilities		
Current liabilities		
Accounts payable	**$ 198,173**	$ 272,818
Distributions payable to unitholders	**29,849**	41,397
Future income taxes	**33,688**	30,198
	261,710	344,413
Long-term debt *(Note 4)*	**739,295**	664,343
Deferred financial credits *(Note 8)*	**24,719**	26,392
Future income taxes	**625,057**	648,821
Asset retirement obligations *(Note 3)*	**211,179**	207,420
	1,600,250	1,546,976
Equity		
Unitholders' capital *(Note 7)*	**5,478,114**	5,471,336
Accumulated deficit	**(1,218,950)**	(1,181,199)
Accumulated other comprehensive income	**73,122**	48,606
	(1,145,828)	(1,132,593)
	4,332,286	4,338,743
	$ 6,194,246	$ 6,230,132

Consolidated Statements of Accumulated Deficit

Three months ended March 31 (CDN$ thousands) (Unaudited)	2009	2008
Accumulated income, beginning of period	**$ 3,175,819**	$ 2,286,927
Net income	**51,786**	121,394
Accumulated income, end of period	**3,227,605**	2,408,321
Accumulated cash distributions, beginning of period	**(4,357,018)**	(3,570,880)
Cash distributions	**(89,537)**	(192,358)
Accumulated cash distributions, end of period	**(4,446,555)**	(3,763,238)
Accumulated deficit, end of period	**$ (1,218,950)**	$ (1,354,917)

Consolidated Statements of Accumulated Other Comprehensive Income

Three months ended March 31 (CDN$ thousands) (Unaudited)	2009	2008
Balance, beginning of period	**$ 48,606**	$ (108,727)
Other comprehensive income	**24,516**	21,222
Balance, end of period	**$ 73,122**	$ (87,505)

Consolidated Statements of Income

Three months ended March 31 (CDN$ thousands except per trust unit amounts) (Unaudited)	2009	2008
Revenues		
Oil and gas sales	**$ 307,515**	$ 510,069
Royalties	**(55,038)**	(93,836)
Commodity derivative instruments *(Note 8)*	**58,645**	(90,379)
Other income	**144**	15,116
	311,266	340,970
Expenses		
Operating	**84,130**	72,016
General and administrative	**18,870**	16,437
Transportation	**6,301**	6,317
Interest *(Note 5)*	**11,997**	6,988
Foreign exchange *(Note 6)*	**853**	3,684
Depletion, depreciation, amortization and accretion	**162,560**	139,794
	284,711	245,236
Income before taxes	**26,555**	95,734
Current taxes	**839**	9,541
Future income tax recovery	**(26,070)**	(35,201)
Net Income	**$ 51,786**	$ 121,394
Net income per trust unit		
Basic	**$ 0.31**	$ 0.82
Diluted	**$ 0.31**	$ 0.82
Weighted average number of trust units outstanding (thousands)[1]		
Basic	**165,716**	147,482
Diluted	**165,716**	147,583

(1) Includes the exchangeable partnership units.

Consolidated Statements of Comprehensive Income

Three months ended March 31 (CDN$ thousands) (Unaudited)	2009	2008
Net income	**$ 51,786**	$ 121,394
Other comprehensive income/(loss), net of tax:		
Unrealized gain/(loss) on marketable securities	**–**	2,578
Realized gains on marketable securities included in net income	**–**	(6,158)
Gains and losses on derivatives designated as hedges in prior periods included in net income	**–**	74
Change in cumulative translation adjustment	**24,516**	24,728
Other comprehensive income/(loss)	**24,516**	21,222
Comprehensive income	**$ 76,302**	$ 142,616

Consolidated Statements of Cash Flows

Three months ended March 31 (CDN$ thousands) (Unaudited)	2009	2008
Operating Activities		
Net income	**$ 51,786**	$ 121,394
Non-cash items add/(deduct):		
Depletion, depreciation, amortization and accretion	**162,560**	139,794
Change in fair value of derivative instruments *(Note 8)*	**(16,721)**	66,472
Unit based compensation *(Note 7)*	**1,379**	1,486
Foreign exchange on translation of senior notes *(Note 6)*	**8,237**	9,233
Future income taxes recovery	**(26,070)**	(35,201)
Amortization of senior notes premium	**(202)**	(153)
Reclassification adjustments from AOCI to net income	**–**	92
Gain on sale of marketable securities	**–**	(8,263)
Asset retirement obligations settled *(Note 3)*	**(3,652)**	(4,020)
	177,317	290,834
Increase in non-cash operating working capital	**(7,929)**	(34,618)
Cash flow from operating activities	**169,388**	256,216
Financing Activities		
Issue of trust units, net of issue costs *(Note 7)*	**5,400**	11,885
Cash distributions to unitholders	**(89,537)**	(192,358)
Increase in bank credit facilities	**66,917**	32,602
(Increase)/Decrease in non-cash financing working capital	**(11,549)**	14,417
Cash flow from financing activities	**(28,769)**	(133,454)
Investing Activities		
Capital expenditures	**(99,874)**	(127,923)
Property acquisitions	**(1,977)**	(7,549)
Property dispositions	**13**	2,122
Proceeds on sale of marketable securities	**–**	18,320
Increase in non-cash investing working capital	**(46,401)**	(10,418)
Cash flow from investing activities	**(148,239)**	(125,448)
Effect of exchange rate changes on cash	**823**	2,437
Change in cash	**(6,797)**	(249)
Cash, beginning of period	**6,922**	1,702
Cash, end of period	**$ 125**	$ 1,453
Supplementary Cash Flow Information		
Cash income taxes paid	**$ –**	$ 9,002
Cash interest paid	**$ 2,701**	$ 8,318

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, 2008. 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, 2008.

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

($ thousands)	March 31, 2009	December 31,2008
Property, plant and equipment	$ 8,634,309	$ 8,497,206
Accumulated depletion, depreciation and accretion	(3,420,678)	(3,250,208)
Net property, plant and equipment	$ 5,213,631	$ 5,246,998

Capitalized development general and administrative ("G&A") expenses of $6,249,000 are included in PP&E for the three months ended March 31, 2009 (March 31, 2008 – $4,909,000). Excluded from PP&E for the depletion and depreciation calculation is $266,688,000 (December 31, 2008 – $257,608,000) related to oil sands projects which have not yet commenced commercial production.

3. ASSET RETIREMENT OBLIGATIONS

The following is a reconciliation of the asset retirement obligations:

($ thousands)	Three months ended March 31, 2009	Year ended December 31, 2008
Asset retirement obligations, beginning of period	$ 207,420	$ 165,719
Corporate acquisition	–	36,784
Changes in estimates	3,473	4,087
Acquisition and development activity	776	7,394
Dispositions	–	(110)
Asset retirement obligations settled	(3,652)	(18,308)
Accretion expense	3,162	11,854
Asset retirement obligations, end of period	$ 211,179	$ 207,420

4. LONG-TERM DEBT

($ thousands)	March 31, 2009	December 31, 2008
Bank credit facilities (a)	$ 447,805	$ 380,888
Senior notes (b)		
US$175 million (issued June 19, 2002)	223,439	217,327
US$54 million (issued October 1, 2003)	68,051	66,128
Total long-term debt	$ 739,295	$ 664,343

(a) Unsecured Bank Credit Facility

Enerplus currently has a $1.4 billion unsecured covenant based facility that matures November 18, 2010. The facility is extendible each year with a bullet payment required at maturity. 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 weighted average interest rate on the facility for the three months ended March 31, 2009 was 1.4% (March 31, 2008 – 4.3%).

(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 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%. At March 31, 2009, the notes have an amortized cost of US$177,467,000 and are translated into Canadian dollars using the period end foreign exchange rate.

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 repayments on the notes at a CDN/US exchange rate of 0.98 or CDN$55,080,000.

5. INTEREST EXPENSE

	Three months ended March 31,	
($ thousands)	**2009**	**2008**
Realized		
Interest on long-term debt	**$ 5,554**	$ 13,345
Unrealized		
Loss/(gain) on cross currency interest rate swap	**7,964**	(8,344)
(Gain)/loss on interest rate swaps	**(1,319)**	2,140
Amortization of the premium on senior unsecured notes	**(202)**	(153)
Interest Expense	**$ 11,997**	$ 6,988

6. FOREIGN EXCHANGE

($ thousands)	**2009**	**2008**
Realized		
Foreign exchange loss	**$ 2,364**	$ 568
Unrealized		
Foreign exchange loss on translation of U.S. dollar denominated senior notes	**8,238**	9,233
Foreign exchange gain on cross currency interest rate swap	**(8,318)**	(4,171)
Foreign exchange gain on foreign exchange swaps	**(1,431)**	(1,946)
Foreign exchange loss	**$ 853**	$ 3,684

7. UNITHOLDERS' CAPITAL

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

($ thousands)	Three months ended March 31, 2009	Year ended December 31, 2008
Trust units	**$ 5,340,787**	$ 5,328,629
Exchangeable partnership units	**116,349**	123,107
Contributed surplus	**20,978**	19,600
Balance, end of period	**$ 5,478,114**	$ 5,471,336

(a) Trust Units

Authorized: Unlimited number of trust units

(thousands)	Three months ended March 31, 2009		Year ended December 31, 2008	
Issued:	**Units**	**Amount**	**Units**	**Amount**
Balance, beginning of period	**162,514**	**$ 5,328,629**	129,813	$ 4,020,228
Issued for cash:				
Pursuant to rights incentive plan	**–**	**–**	210	6,755
Cancelled trust units	**–**	**–**	(116)	(3,794)
Exchangeable limited partnership units exchanged	**169**	**6,758**	786	31,444
Trust unit rights incentive plan (non-cash) – exercised	**–**	**–**	–	3,642
DRIP*, net of redemptions	**238**	**5,400**	1,671	63,761
Issued for acquisition of corporate and property interests (non-cash)	**–**	**–**	30,150	1,206,593
	162,921	**$ 5,340,787**	162,514	$ 5,328,629
Equivalent exchangeable partnership units	**2,907**	**116,349**	3,076	123,107
Balance, end of period	**165,828**	**$ 5,457,136**	165,590	$ 5,451,736

* Distribution Reinvestment and Unit Purchase Plan

(b) Exchangeable Partnership Units

Enerplus Exchangeable Limited Partnership Units are exchangeable into Enerplus trust units at a ratio of 0.425 of an Enerplus trust unit for each limited partnership unit. During the period January 1, 2009 to March 31, 2009, 397,000 exchangeable limited partnership units were converted into 169,000 trust units. As at March 31, 2009, the 6,841,000 outstanding exchangeable partnership units represent the equivalent of 2,907,000 trust units.

(thousands)	Three months ended March 31, 2009		Year ended December 31, 2008	
Issued:	**Units**	**Amount**	**Units**	**Amount**
Assumed on February 13, 2008	**7,238**	**$ 123,107**	9,087	$ 154,551
Exchanged for trust units	**(397)**	**(6,758)**	(1,849)	(31,444)
Balance, end of period	**6,841**	**$ 116,349**	7,238	$ 123,107

(c) Contributed Surplus

($ thousands)	Three months ended March 31, 2009	Year ended December 31, 2008
Balance, beginning of period	**$ 19,600**	$ 12,452
Trust unit rights incentive plan (non-cash) – exercised	**–**	(3,642)
Trust unit rights incentive plan (non-cash) – expensed	**1,378**	6,996
Cancelled trust units	**–**	3,794
Balance, end of period	**$ 20,978**	$ 19,600

(d) Trust Unit Rights Incentive Plan

As at March 31, 2009 a total of 5,888,000 rights issued pursuant to the Trust Unit Rights Incentive Plan ("Rights Incentive Plan") with an average exercise price of $35.35 were outstanding. This represents 3.6% of the total trust units outstanding of which 2,426,000 rights, with an average exercise price of $45.05, 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, 2009 have not reduced the exercise price of the outstanding rights.

The Fund uses a binomial lattice option-pricing model to calculate the estimated fair value of rights granted under the plan. The following assumptions were used to arrive at the estimate of fair value for rights granted during the three months ended March 31, 2009:

	Three months ended March 31, 2009
Dividend yield	**12.61%**
Volatility	**44.41%**
Risk-free interest rate	**1.69%**
Forfeiture rate	**12.40%**
Right's exercise price reduction	**$ 1.92**

Non-cash compensation costs of $1,379,000 ($0.01 per unit) related to rights issued were charged to general and administrative expense during the three months ended March 31, 2009 (March 31, 2008 – $1,486,000, $0.01 per unit). Activity for the rights issued pursuant to the Rights Plan is as follows:

	Three months ended March 31, 2009		Year ended December 31, 2008	
	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	**4,001**	**$ 45.05**	3,404	$ 47.59
Granted	**1,964**	**17.14**	1,403	42.00
Exercised	**–**	**–**	(210)	32.22
Forfeited and expired	**(77)**	**44.58**	(596)	44.94
End of period	**5,888**	**$ 35.35**	4,001	$ 45.05
Rights exercisable at end of period	**2,426**	**$ 45.05**	2,024	$ 46.44

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

(e) Basic and Diluted per Trust Unit Calculations

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

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

	Three months ended March 31,	
(thousands)	2009	2008
Weighted average units	**165,716**	147,482
Dilutive impact of rights	**–**	101
Diluted trust units	**165,716**	147,583

(f) Performance Trust Unit Plan

In 2007 the Fund adopted a Performance Trust Unit ("PTU") plan for executives and employees. For the period ended March 31, 2009 the Fund recorded cash compensation costs of $1,826,000 ($1,083,000 period ended March 31, 2008) under the plan which are included in general and administrative expenses.

At March 31, 2009 there were 405,000 PTU's outstanding (422,000 – March 31, 2008).

(g) Restricted Trust Unit Plan

In 2009 the Fund adopted a new Restricted Trust Unit ("RTU") plan for executives and employees, which will replace the PTU plan. Under the RTU plan 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 one-third at the end of each year for three years. Upon vesting, plan participants receive a cash payment based on the value of the underlying trust units plus notional accrued distributions.

For the period ended March 31, 2009 the Fund recorded cash compensation costs of $1,293,000 under the RTU plan which are included in general and administrative expenses.

At March 31, 2009 there were 864,000 RTU's outstanding.

8. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

i. Cash

Cash is classified as held-for-trading and is reported at fair value.

ii. Accounts Receivable

Accounts receivable are classified as loans and receivables and are reported at amortized cost. At March 31, 2009 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 2009 the Fund did not hold any investments in publicly traded marketable securities.

Marketable securities without a quoted market price in an active market are reported at cost unless an other than temporary impairment exists. As at March 31, 2009 the Fund reported investments in marketable securities of private companies at cost of $47,116,000 (December 31, 2008 – $47,116,000) in Other Assets on the Consolidated Balance Sheet. Realized gains and losses on marketable securities are included in other income.

iv. Accounts Payable & Distributions Payable to Unitholders

Accounts payable and distributions payable to unitholders are classified as other liabilities and are reported at amortized cost. At March 31, 2009 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 cost. At March 31, 2009 the carrying value of the bank credit facility approximated its fair value.

US$175 million senior notes

The US$175,000,000 senior notes, which are classified as other liabilities, are reported at amortized cost of US$177,467,000 and are translated to Canadian dollars at the period end exchange rate. At March 31, 2009 the Canadian dollar amortized cost of the senior notes was approximately $223,439,000 and the fair value of these notes was $221,444,000.

US$54 million senior notes

The US$54,000,000 senior notes, which are classified as other liabilities, are 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, 2009 the Canadian dollar amortized cost of the senior notes was approximately $68,051,000 and the fair value of these notes was $63,755,000.

(b) 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, 2009 a current deferred financial asset of $134,898,000, a non-current deferred financial asset of $8,288,000 and a non-current deferred financial credit of $24,719,000 are recorded on the Consolidated Balance Sheet.

The deferred financial asset relating to crude oil instruments of $76,314,000 at March 31, 2009 consists of the fair value of the financial instruments, representing a gain position of $91,975,000 less the related deferred premiums of $15,661,000. The deferred financial asset relating to natural gas instruments of $57,284,000 at March 31, 2009 consists of the fair value of the financial instruments of $72,660,000 less the related deferred premiums of $15,376,000.

The following table summarizes the fair value as at March 31, 2009 and change in fair value for the period ended March 31, 2009 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	$ (10,051)	$ (16,341)	$ 6,857	$ 348	$ 96,641	$ 24,292	$ 101,746
Change in fair value gain/(loss)	1,319(1)	354(2)	1,431(3)	952(4)	(20,327)(5)	32,992(5)	16,721
Deferred financial assets/(credits), end of period	**$ (8,732)**	**$ (15,987)**	**$ 8,288**	**$ 1,300**	**$ 76,314**	**$ 57,284**	**$118,467**
Balance sheet classification:							
Current asset/(liability)	**$ –**	**$ –**	**$ –**	**$ 1,300**	**$ 76,314**	**$ 57,284**	**$134,898**
Non-current asset/(liability)	**$ (8,732)**	**$ (15,987)**	**$ 8,288**	**$ –**	**$ –**	**$ –**	**$ (16,431)**

(1) Recorded in interest expense.
(2) Recorded in foreign exchange expense (gain of $8,318) and interest expense (loss of $7,964).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments (see below).

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

($ thousands)	Three months ended March 31, 2009	Three months ended March 31, 2008
Gain/(loss) due to change in fair value	**$ 12,665**	$ (79,445)
Net realized cash gain/(loss)	**45,980**	(10,934)
Commodity derivative instruments gain/(loss)	**$ 58,645**	$ (90,379)

(c) Commodity Risk Management

The Fund is exposed to commodity price fluctuations as part of its normal business operations, particularly in relation to its crude oil and natural gas sales. The Fund manages a portion of these risks through a combination of financial derivative and physical delivery sales contracts. The Fund's policy is to enter into commodity contracts considered appropriate to a maximum of 80% of forecasted production volumes net of royalties. The Fund's outstanding commodity derivative contracts as at April 29, 2009 are summarized below.

Crude Oil:

		WTI US$/bbl			
	Daily Volumes bbls/day	**Sold Call**	**Purchased Put**	**Sold Put**	**Fixed Price and Swaps**
Term					
April 1, 2009 – December 31, 2009					
Put	1,400	–	$ 122.00	–	–
Put	1,000	–	$ 120.00	–	–
Put	500	–	$ 116.00	–	–
Collar	850	$ 100.00	$ 85.00	–	–
Collar	1,000	–	$ 92.00	$ 79.00	–
3-Way option	1,000	$ 85.00	$ 70.00	$ 57.50	–
3-Way option	1,000	$ 95.00	$ 79.00	$ 62.00	–
Swap	500	–	–	–	$ 100.05

There were no new contracts entered into during or subsequent to the quarter.

Natural Gas:

		AECO CDN$/Mcf			
	Daily Volumes MMcf/day	**Sold Call**	**Purchased Put**	**Sold Put**	**Fixed Price and Swaps**
Term					
April 1, 2009 – October 31, 2009					
Put	9.5	–	$ 8.44	–	–
Put	14.2	–	$ 7.70	–	–
Put	2.8	–	$ 7.78	–	–
Put	4.7	–	$ 7.87	–	–
Put	4.7	–	$ 7.72	–	–
Collar	2.8	–	$ 9.23	$ 7.65	–
Collar	2.8	–	$ 9.50	$ 7.91	–
Collar	5.7	–	$ 9.60	$ 7.91	–
Swap	3.8	–	–	–	$ 7.86
April 1, 2009 – October 31, 2010					
Swap	23.7	–	–	–	$ 7.33
November 1, 2009 – March 31, 2010					
Put	9.5	–	$ 8.97	–	–
Put	2.8	–	$ 9.07	–	–
Put	9.5	–	$ 9.06	–	–
Call	4.7	$ 12.13	–	–	–
2009 - 2010					
Physical	2.0	–	–	–	$ 2.67

There were no new contracts entered into during or subsequent to the quarter.

The following sensitivities show the impact to after-tax net income of the respective changes in forward crude oil and natural gas prices as at March 31, 2009 on the Fund's outstanding commodity derivative contracts at that time with all other variables held constant:

	Increase/(decrease) to after-tax net income	
($ thousands)	25% decrease in forward prices	25% increase in forward prices
Crude oil derivative contracts	**$ 15,364**	**$ (16,500)**
Natural gas derivative contracts	**$ 20,378**	**$ (19,642)**

Electricity:

The Fund is subject to electricity price fluctuations and it manages this risk by entering into forward fixed rate electricity derivative April 29, 2009 are summarized below.

Term	Volumes MWh	Price CDN$/MWh
April 1, 2009 – December 31, 2009	4.0	$ 74.50
April 1, 2009 – December 31, 2009(1)	2.0	$ 64.00
April 1, 2009 – December 31, 2010	4.0	$ 77.50
April 1, 2009 – December 31, 2010(1)	2.0	$ 68.75

(1) Electricity contracts entered into during the first quarter of 2009

Board of Directors

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Calgary, Alberta

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Vancouver, British Columbia

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Corporate Director
Calgary, Alberta

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

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

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

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

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

Harry B. Wheeler(5)(7)
Corporate Director
Calgary, Alberta

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

Robert L. Zorich(4)(9)
Managing Director
EnCap Investments L.P.
Houston, Texas

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

Officers

Gordon J. Kerr
President &
Chief Executive Officer

Garry A. Tanner
Executive Vice President & Chief Operating Officer

Ian C. Dundas
Senior Vice President,
Business Development

Robert J. Waters
Senior Vice President & Chief Financial Officer

Robert W. Symonds
Vice President, Canadian Operations

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

Ray J. Daniels
Vice President, Oil Sands

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Vice President, Finance

Dana W. Johnson
President, U.S. Operations

Lyonel G. Kawa
Vice President,
Information Services

Robert A. Kehrig
Vice President,
Resource Development

Jennifer F. Koury
Vice President,
Corporate Services

Eric G. Le Dain
Vice President, Regulatory Environment, Marketing

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

Daniel M. Stevens
Vice President,
Development Services

Kenneth W. Young
Vice President, Land

Jodine J. Jenson Labrie
Controller, Finance

Corporate Information

Operating Companies Owned by Enerplus Resources Fund

EnerMark Inc.
Enerplus Resources Corporation
Enerplus Commercial Trust
Enerplus Resources (USA) Corporation
FET Operating Partnership

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
Deloitte & Touche LLP
Calgary, Alberta

Transfer Agent
Computershare Trust Company of Canada
Calgary, Alberta
Toll free: 1.866.921.0978

U.S. Co-Transfer Agent
Computershare Trust Company, N.A.
Golden, CO

Independent Reserve Engineers
Sproule Associates Limited
Calgary, Alberta

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates Inc.
Dallas, Texas

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

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

Telephone: 720.279.5500
Fax: 720.279.5550

Abbreviations

AECO Alberta Energy Company interconnect with the Nova Gas System, the Canadian benchmark for natural gas pricing purposes

bbl(s)/day barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons

BOE(s)/day barrel of oil equivalent per day (6 Mcf of gas:1 BOE)

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

GAAP Generally accepted accounting principles

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent

Mcf/day thousand cubic feet per day

MMbbl(s) million barrels

MMBOE million barrels of oil equivalent

MMBtu million British Thermal Units

MMcf/day million cubic feet per day

MWh Megawatt hour(s) of electricity

NGLs natural gas liquids

NYSE New York Stock Exchange

SAGD steam assisted gravity drainage

SEDAR System for Electronic Document Analysis and Retrieval

TSX Toronto Stock Exchange

WI percentage working interest ownership

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