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NEWS RELEASE

May 4, 2007

Enerplus announces 2007 first quarter operating and financial results

Enerplus Resources Fund
TSX - ERF.un
NYSE - ERF

CALGARY, May 4 /CNW/ - Enerplus Resources Fund ("Enerplus") is pleased to announce our results from operations for the period ending March 31, 2007. Highlights are as follows:

- Our efforts during the first quarter were focused on the execution of our internal development program and the expansion of our operations through the acquisition of over $240 million of additional assets in the Alberta oil sands and the United States.
- We are pleased to report that our operating and financial results to date are essentially meeting our expectations. Production volumes averaged approximately 86,000 BOE/day, up slightly over the first quarter of 2006 and in line with our 2007 full year guidance of 85,000 BOE/day.
- Cash flow from operations was slightly ahead of last year at $193.2 million compared to $189.3 million in the first quarter of 2006.
- Monthly cash distributions to unitholders were $0.42 per unit, a level that has been maintained over the past 19 months, and totaled $1.26 per unit for the quarter.
- Through our development capital program, we invested $110 million during the first quarter with the majority of our spending focused on crude oil. We drilled 106 gross wells, (39.7 net), which was lower compared to the same quarter last year due to the deferral of our shallow gas and coalbed methane drilling programs. Despite the reduction in the total number of wells drilled, our capital spending is in line with expectations as the costs associated with drilling oil wells are higher than those for shallow natural gas.
- Our total capital spending for the year will increase marginally to approximately $415 million ($410 million as per our original guidance plus $5 million associated with the Kirby acquisition) as we will shift $30 million from our other Canadian conventional oil and gas projects to increase our U.S. program given the robust economics associated with our Sleeping Giant project.
- With the decrease in capital spending programs across the industry this year, we are starting to see deflationary pressures on the cost of drilling and oil field services. At this point, it is premature to indicate what savings we may see throughout 2007, but we will continue to actively manage our costs and may see greater capital efficiencies this year. Our operating costs at $8.53 per BOE were slightly ahead of guidance however we continue to expect full year

operating costs to be $8.45 per BOE.

- Our payout ratio for the quarter was 82% compared to the first quarter of 2006 at 79%. This payout ratio is calculated using GAAP measures "cash flow from operating activities" versus the previous non-GAAP measure "funds flow from operations". The difference is that cash flow from operating activities includes changes in non-cash working capital, which can introduce volatility in reported cash flow and payout ratios. For example, during the first quarter, we had a working capital adjustment of approximately $26 million which reduced our cash flow from operating activities relative to funds flow and increased our payout ratio relative to our previous methodology.
- Our debt-to-cash flow remains at a conservative 0.8 times.

SUMMARY FINANCIAL AND OPERATING HIGHLIGHTS

All amounts are stated in Canadian dollars unless otherwise specified. In accordance with Canadian practice, production volumes, reserve volumes and 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. Certain prior year amounts have been restated to reflect current year presentation. Readers are also urged to review the Management's Discussion & Analysis (MD&A) and Audited Financial Statements for more fulsome disclosure on our operations. These reports can be found on our website at www.enerplus.com, our SEDAR profile at www.sedar.com and as part of our SEC filings available on www.sec.gov.

SELECTED FINANCIAL RESULTS

For the three months ended March 31,	2007	2006
Financial (000's)		
Net Income	$ 107,873	$ 127,292
Cash Flow from Operating Activities	193,181	189,281
Cash Distributions to Unitholders(1)	157,671	150,245
Cash Withheld for Acquisitions and Capital Expenditures	35,510	39,036
Debt Outstanding (net of cash)	716,860	525,864
Development Capital Spending	109,952	128,748
Acquisitions	63,423	30,027
Divestments	-	19,717
Financial per Unit(2)		
Net Income	$ 0.88	$ 1.08
Cash Flow from Operating Activities	1.57	1.60
Cash Distributions to Unitholders(1)	1.28	1.26
Cash Withheld for Acquisitions and Capital Expenditures	0.29	0.51
Payout Ratio(3)	82%	79%
Selected Financial Results per BOE(4)		
Oil & Gas Sales(5)	$ 49.08	$ 52.27
Royalties	(9.12)	(10.40)
Commodity Derivative Instruments	1.01	(2.98)
Operating Costs	(8.55)	(7.57)
General and Administrative	(1.94)	(1.58)
Interest and Foreign Exchange	(1.32)	(0.90)

Taxes	(0.38)	(0.68)
Restoration and Abandonment	(0.42)	(0.40)
Cash Flow from Operating Activities before changes in non-cash working capital	$ 28.36	$ 27.76
Weighted Average Number of Trust Units Outstanding (thousands)	123,282	118,221
Debt/Trailing 12 Month Cash Flow Ratio	0.8x	0.6x

SELECTED OPERATING RESULTS

For the three months ended March 31,	2007	2006
Average Daily Production		
Natural gas (Mcf/day)	275,714	270,765
Crude oil (bbls/day)	35,567	35,853
NGLs (bbls/day)	4,509	4,411
Total (BOE/day)	86,028	85,392
% Natural gas	53%	53%
Average Selling Price(5)		
Natural gas (per Mcf)	$ 7.21	$ 8.33
Crude oil (per bbl)	57.26	55.20
NGLs (per bbl)	44.09	50.57
US$ exchange rate	0.85	0.87
Net Wells drilled	40	124
Success Rate	98%	100%

(1) Calculated based on distributions paid or payable. Cash distributions to unitholders per unit will not correspond to the actual monthly distributions of $1.26 as a result of using the weighted average trust units outstanding for the period.
(2) Based on weighted average trust units outstanding for the period.
(3) Calculated as Cash Distributions to Unitholders divided by Cash Flow from Operating Activities.
(4) Non-cash amounts have been excluded.
(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

TRUST UNIT TRADING SUMMARY for the three months ended March 31, 2007	TSX - ERF.un (CDN$)	NYSE - ERF (US$)
High	52.99	44.67
Low	46.50	39.53
Close	48.70	42.22

2007 CASH DISTRIBUTIONS PER TRUST UNIT		CDN$	US$
Production Month	Payment Month		

January	March	$ 0.42	$ 0.36
February	April	0.42	0.37
March	May	0.42	0.38(*)
First Quarter Total		$ 1.26	$ 1.11

(*) Calculated using an exchange rate of 1.12

OPERATIONS ACTIVITY

2007 DEVELOPMENT ACTIVITY

	Three months ended March 31, 2007		
		Wells Drilled	
PLAY TYPE	Capital Spending ($ millions)	Gross	Net
Shallow Natural Gas & CBM	3.2	16	7.6
Crude Oil Waterfloods	17.2	16	13.3
Bakken Oil	37.8	9	6.6
Oil Sands	10.1	-	-
Other Conventional Oil & Gas	41.7	65	12.2
Total	$ 110.0	106.0	39.7

Drilling success rate - 98%

Our highest concentration of capital spending during the quarter occurred at our Sleeping Giant Bakken oil property in the U.S. We drilled 9 gross wells (6.6 net wells) completing our original two wells per section drilling program in the heart of the field and continuing with our third well per section pilot program. Successful initial results from this pilot have resulted in an additional 9 wells being added to this program for a total of 16 wells in 2007. In addition, we acquired seismic over the eastern portion of the field and are currently interpreting it to evaluate other opportunities in the deeper Red River formation. We completed 5 refracs during the quarter and added an additional 9 refracs in the latter part of the year for a total of 16 planned for 2007. Results continue to be very positive in terms of increased rates and recovery. Given the increased opportunity and robust economics associated with the Sleeping Giant project, we are increasing our capital spending from $70 million to $100 million in 2007. Our total capital spending for the year will increase marginally to approximately $415 million ($410 million as per our original guidance plus $5 million associated with the Kirby acquisition) as we will shift $30 million from our other Canadian conventional oil and gas projects to increased our U.S. program.

ACQUISITIONS

On January 31, we acquired additional assets in the United States with the purchase of a gross-overriding royalty interest in the Jonah natural gas field in Wyoming for $61.3 million. This is a modest increase to our U.S. portfolio and establishes a new area with significant gas development potential. The attractiveness of this asset relates to the high cash flow per

BOE as the gross-overriding royalty is not subject to deductions for operating costs, royalties or any future development capital. This acquisition also comes with an RLI of 15.9 years and significant future development opportunities from which Enerplus will benefit but will not be required to fund.

On March 22, we announced the acquisition of a 90% interest in the Kirby Oil Sands Partnership located in the heart of the Athabasca oil sands fairway of Alberta for $182.5 million. This strategic acquisition provides Enerplus with additional long-term oil sands assets with steam assisted gravity drainage ("SAGD") development potential that we believe will add significant value for our unitholders in the years to come. Oil sands assets are a key resource play for Enerplus given their lower geologic risk and the scalable development associated with these types of assets. The addition of an operated SAGD project compliments our existing portfolio of non-operated oil sands assets which include the mining and SAGD projects on the Joslyn lease.

The Kirby oil sands leases cover a large land block of 43,360 gross acres (over 67 sections of land) near several other major SAGD development projects currently on production. An independent engineering assessment conducted by GLJ Petroleum Consultants Ltd. ("GLJ") indicates a "best estimate" of contingent resources of 244 million barrels of bitumen (approximately 220 million barrels net to Enerplus). Our initial development plans include a 10,000 bbl/day SAGD project (9,000 bbls/day net) starting in 2011 with further expansion capability to a total of 30,000 - 40,000 bbls/day of gross bitumen production (27,000 - 36,000 bbls/day net to Enerplus) over time. We expect the project life of these SAGD developments to be in the order of 25 years. Our initial capital requirements to bring the first 10,000 bbls/day of production on stream are expected to be approximately $320 million net to Enerplus including estimates for cost inflation and contingencies. Further sustaining capital will be required over the remaining life of the projects.

The combined cost of these acquisitions was $243.8 million and was initially funded through our existing credit facilities. In conjunction with the Kirby transaction, we announced an equity offering of trust units which closed April 10, 2007 raising net proceeds of $200 million in addition to a private placement of 1.1 million units with the vendor representing consideration of $54.7 million. This total financing of $254.7 million maintains our healthy balance sheet and positions us to execute other potential merger and acquisition ("M&A") opportunities through the year.

CANADIAN FEDERAL GOVERNMENT TRUST TAX PROPOSAL

We have continued our lobby efforts against the federal government's proposal to implement a tax on income trusts as announced on October 31, 2006. Despite recommendations from the Federal Finance Committee released in February which offered suggestions that would have reduced the impact of this proposal, the Conservative government has not adjusted their original proposal and unfortunately elected to include the proposal as it existed together with the federal budget, which was passed in the House of Commons on March 19, 2007, into an implementation bill. This bill has received first reading in the House of Commons with the second reading and debate currently underway. Three readings in the House of Commons are required before a bill is voted upon. We encourage unitholders to continue to voice their concerns to their Member of Parliament and the Prime Minister.

FEDERAL AND PROVINCIAL GREENHOUSE GAS EMISSION REDUCTION PROPOSALS

On March 8th, the Alberta government introduced amendments to the provincial Climate Change and Emissions Management Act ("CCEMA") that would impose facility-specific targets intended to reduce greenhouse gas emissions. In addition, on April 26th, the Canadian federal government announced its proposed plan to reduce emissions. Both of these plans reflect intensity based

reductions (expressed as a percentage of the facility's volume of emissions per unit of production) versus absolute reductions and will initially impact large, final emitters (LFEs). Under the Alberta proposal, a LFE is defined as those facilities that are producing in excess of 100,000 tonnes of greenhouse gases per year.

The targets are designed to reduce emission intensity measured from different starting points under the two proposals but no earlier than 2003 for individual LFEs. A number of mechanisms have been proposed to allow producers to mitigate the impact where the targeted reductions are not met including contributions to technology funds, offsetting credits earned at other outside covered sources and credit trading. Clarification and further detail surrounding regulations are still to come and the federal government has stated that they will work to harmonize the federal proposals with the provincial proposals such that they are not additive to the provincial obligations but rather incremental.

Early assessments are that the costs to producers will be well below $1.00 per produced barrel at targeted LFEs. We do not anticipate a significant immediate impact on our existing operations and factored in a provision for emission-related costs in making our Kirby acquisition that we believe adequately reflects the impact of the proposals as put forward.

FUTURE FOCUS

We continue to focus on the business of running a successful oil and gas operation which will serve us well regardless of structure or commodity price environment. We have built a technically-driven organization that is creating value for our unitholders by maximizing the potential within our existing assets and adding strategic assets to our portfolio. We have a high quality, long-life asset base and a robust opportunity set which supports our yield oriented model. Approximately 50% of our production and 70% of our reserves are resource play oriented. Our conventional oil and natural gas assets offer approximately $2 billion of future development potential across a diverse mix of quality assets and equates to between 4 and 5 years of development activity based upon our current spending levels providing us with the opportunity to maintain our production volumes over this period.

In addition to our conventional opportunity set we have the ability to grow via our oil sands assets and future M&A activity. We have a positive long-term price view for commodities and the acquisition of oil sands assets supports this view. Through our recent acquisition of Kirby and our existing interest in the Joslyn lease, we have over 443 million barrels of "best estimate" contingent resource potential net to Enerplus as well as 57 million barrels of proven plus probable reserves. Together these projects represent $3 billion of attractive future development potential including both initial and sustaining capital. These projects provide us with a clear strategic advantage over many other operators given their low geologic risk and the production and reserve profile that lies ahead. In aggregate, our current oil sands opportunities have the potential to add over 60,000 bbls/day of production net to Enerplus over the next 10+ years.

Our healthy balance sheet and developments in the M&A market are supportive of additional acquisitions this year. The Canadian M&A market is improving for buyers and we are watching the U.S. market develop as U.S. upstream master limited partnerships enter the market. Our acquisition priorities this year are to acquire an operated SAGD project and to build our U.S. business.

We believe that investor demographics, the current low interest rate environment, the demand for yield product and our asset base will continue to support a yield-oriented business model with a premium valuation over a traditional exploration and production model. Our lower risk approach to the energy business, resource play focus, and our disciplined acquisition strategy will serve us well regardless of structure. In the event that the proposed tax

on trusts is implemented, we believe there is significant value in the four-year tax exemption period and would utilize our tax pools and adopt the most advantageous structure to minimize our tax liabilities beyond that time.

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

The following discussion and analysis of financial results is dated May 3, 2007 and is to be read in conjunction with:

- the MD&A and audited consolidated financial statements as at and for the years ended December 31, 2006 and 2005; and
- the unaudited interim consolidated financial statements as at and for the three months ended March 31, 2007 and 2006.

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, production volumes, reserve volumes and revenues are reported on a gross basis, before deduction of crown and other royalties, unless otherwise stated. Oil and natural gas reserves and production are presented on a company interest basis which is not a term defined or recognized under NI 51- 101. Therefore, our company interest reserves may not be comparable to similar measures presented by other issuers. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading. Certain prior year amounts have been restated to reflect current year presentation.

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 statements.

NON-GAAP MEASURES

Historically we used the non-GAAP measure funds flow from operations to analyze operating performance, leverage and liquidity. We are now utilizing the GAAP measure cash flow from operating activities ("cash flow") instead of funds flow from operating activities. The difference is that cash flow from operating activities includes changes in non-cash working capital and appears on our Consolidated Statements of Cash Flows.

We also historically used the non-GAAP measure cash available for distribution. We are now using cash distributions to unitholders ("cash distributions") which also appears on our Consolidated Statements of Cash Flows. Cash available for distribution was based on the twelve month production period January through December wherein the related distributions were paid with a two month lag or March through February respectively. Cash distributions include amounts paid or declared during the calendar year which relate to the twelve month production period December through November wherein the related distributions are paid February through January.

Our payout ratio was previously calculated as cash available for distribution divided by funds flow; however, as a result of the above-mentioned changes, our payout ratio is now calculated as cash distributions divided by cash flow from operating activities. This reflects the proportion of cash flow paid out to investors and not reinvested in the business. The term payout ratio does not have a standardized meaning as prescribed by GAAP and therefore may not be comparable with the calculation of a similar measure by other entities.

Refer to the Liquidity and Capital Resources section of the MD&A for further information on cash flow, cash distributions and payout ratio.

ACCOUNTING CHANGES

Our financial statements for the first quarter of 2007 reflect a number of new accounting standards introduced by the Canadian Institute of Chartered Accountants ("CICA"). The implementation of these new standards impacts the comparability of our financial results.

On January 1, 2007 we prospectively adopted CICA Handbook Sections 3855 "Financial Instruments - Recognition and Measurement", Section 3865 "Hedges" and Section 1530 "Comprehensive Income". These standards generally require a greater portion of the balance sheet to be measured at fair value with changes in fair value recorded in either net income or a new earnings measurement called other comprehensive income ("OCI"). The standards also provide new guidance on the accounting for derivatives in hedging relationships in that all derivatives are required to be recorded at fair value on the balance sheet. The impact of these accounting changes on our financial statements is summarized below:

- Previously we designated our cross currency interest rate swap ("CCIRS") as a fair value hedge. On January 1, 2007 we elected to stop designating the CCIRS as a qualified hedge and as a result we recorded the swap on our Consolidated Balance Sheet at fair value with an increase of $56.0 million recorded to opening accumulated deficit. Subsequent changes in the fair value of the interest component of the CCIRS will be recorded in interest expense and subsequent changes in the fair value of the foreign exchange component of the CCIRS will be recorded in foreign exchange gain/loss. In addition, the carrying value of the underlying US$175,000,000 senior unsecured notes was adjusted to the January 1, 2007 fair value of $208.2 million, with a decrease of $51.3 million recorded to opening accumulated deficit. Going forward these debentures will be reported at amortized cost and will be translated into Canadian dollars at the period end foreign exchange rate.

- Historically, deferred charges associated with issuing our senior unsecured notes were being amortized to income over the term of the debentures. On January 1, 2007 these deferred charges of $1.0 million were recorded to the opening accumulated deficit balance.

- Previously our interest rate and electricity swaps were designated as cash flow hedges. On January 1, 2007 we elected to stop designating these swaps as cash flow hedges and recorded these items on our Consolidated Balance Sheet at fair values of $(0.7) million and $1.5 million respectively, resulting in an increase of $0.7 million recorded to opening accumulated other comprehensive income ("AOCI"). This amount will be amortized and recorded in interest expense and operating expense over the term of the contracts. Subsequent changes in the fair value of the interest rate swaps will be recorded in interest expense while subsequent changes in the fair value of the electricity swaps will be recorded in operating expenses.

- Previously our investments in publicly traded marketable securities were recorded on our Consolidated Balance Sheets at cost. On January 1, 2007 these investments were recorded on our Consolidated Balance Sheet at a fair value of $30.0 million, with an increase of $14.3 million recorded to opening AOCI. Subsequent changes in fair value will be recorded in OCI. The cumulative gains and losses recorded in AOCI will be reclassified to income upon disposition of the marketable securities.

- Amounts previously recorded in the cumulative translation adjustment

of $9.0 million at January 1, 2007 were reclassified as a decrease to opening AOCI. Subsequent changes in the cumulative translation adjustment will be recorded in OCI.

Upon adoption of these standards, our total assets increased by $17.7 million and our total liabilities increased by $8.5 million.

UPDATE ON CANADIAN GOVERNMENT ANNOUNCEMENT ON INTENTION TO TAX TRUSTS

Bill C-52 "an act to implement certain provisions of the budget tabled in Parliament on March 19, 2007" and certain other proposals including the proposal to tax trusts, was introduced into the House of Commons on March 29, 2007 and is currently in second reading and debate. Bill C-52 would amend the Income Tax Act such that commencing January 1, 2011 (provided that the Fund only experiences "normal growth" and no "undue expansion") certain distributions from the Fund will be characterized as dividends and the Fund will be subject to tax at the same effective rate as Canadian corporations.

If Bill C-52 is "substantively enacted" as put forward, at that time a one-time non-cash charge to earnings and a corresponding increase to the future tax liability will be recorded. In addition, at that time we would also present our December 31, 2006 reserves on both a pre-tax and an after- tax basis.

See the Annual Information Form "General development of Enerplus Resources Fund - Federal Government Pronouncements on Income Trusts" (page 4) for further information.

OVERVIEW

During the quarter we achieved a modest increase in production to 86,028 BOE/day and increased our cash flow to $193.2 million despite decreased natural gas prices. Development capital spending totaled $110.0 million and remains on target with our annual guidance. On January 31, 2007, we acquired gross-overriding royalty interests in the Jonah natural gas field in Wyoming ("Jonah") for total consideration of $61.3 million. We also entered into an agreement to acquire a 90% interest in the Kirby Oil Sands Partnership ("Kirby"), a privately held partnership operating in the Athabasca oil sands fairway of Alberta, for total consideration of $182.5 million ($127.8 million in cash and $54.7 million in equity). This acquisition closed subsequent to the quarter on April 10, 2007 concurrent with the closing of an equity offering of 4.25 million trust units at a price of $49.55 per unit for gross proceeds of $210.6 million.

RESULTS OF OPERATIONS

Production

During the first quarter of 2007 production volumes averaged 86,028 BOE/day representing a 1% increase over 2006 first quarter volumes of 85,392 BOE/day. For the three months ended March 31, 2007 production volumes were weighted 53% natural gas and 47% crude oil and natural gas liquids on a BOE basis, unchanged compared to the first quarter of 2006. Average production volumes for the three months ended March 31, 2007 and 2006 are outlined below:

	Three months ended March 31,		
Daily Production Volumes	2007	2006	% Change
Natural gas (Mcf/day)	275,714	270,765	2%
Crude oil (bbls/day)	35,567	35,853	(1%)
Natural gas liquids (bbls/day)	4,509	4,411	2%
Total daily sales (BOE/day)	86,028	85,392	1%

Based on the results of our first quarter we are maintaining our annual production estimate of 85,000 BOE/day and 2007 exit rate of 86,000 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, 2007 and 2006. It also compares the benchmark price indices for the same periods.

Average Selling Price(1)	Three months ended March 31, 2007	2006	% Change
Natural gas (per Mcf)	$ 7.21	$ 8.33	(13%)
Crude oil (per bbl)	57.26	55.20	4%
Natural gas liquids (per bbl)	44.09	50.57	(13%)
Per BOE	$ 49.08	$ 52.27	(6%)

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

Average Benchmark Pricing	Three months ended March 31, 2007	2006	% Change
AECO natural gas - monthly index (CDN$/Mcf)	$ 7.46	$ 9.27	(20%)
AECO natural gas - daily index (CDN$/Mcf)	7.41	7.56	(2%)
NYMEX natural gas - monthly NX3 index (US$/Mcf)	6.96	9.07	(23%)
NYMEX natural gas - monthly NX3 index CDN$ equivalent (CDN$/Mcf)	8.19	10.43	(21%)
WTI crude oil (US$/bbl)	58.23	63.48	(8%)
WTI crude oil: CDN$ equivalent (CDN$/bbl)	68.51	72.99	(6%)
US$/CDN$ exchange rate	$ 0.85	$ 0.87	(2%)

We realized an average price on our natural gas of $7.21/Mcf (net of transportation costs) during the three months ended March 31, 2007, a decrease of 13% from $8.33/Mcf for the same period in 2006. A warmer winter through to February, strong industry production and high storage inventories reduced industry pricing year-over-year. In comparison to the first quarter of 2006, the AECO monthly index price for natural gas decreased 20% and the AECO daily index price decreased 2%. We sell our natural gas under both month and day AECO index contracts. Our realized natural gas price decrease of 13% during the first quarter was comparable to the 11% average decrease of the combined indices.

The average price we received for our crude oil during the three months ended March 31, 2007 increased 4% to $57.26/bbl (net of transportation costs) from $55.20/bbl during the same period in 2006. In comparison, the West Texas Intermediate ("WTI") crude oil benchmark price, after adjusting for the change in the US$ exchange rate, decreased 6% from the corresponding period in 2006. The relative strength in our sales price can be attributed to improved pricing differentials year-over-year relative to WTI for the majority of our crude oil

production.

The Canadian dollar weakened 2% against the U.S. dollar, based on the average quarterly exchange rate, during the first quarter of 2007 compared to the same period in 2006. 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 increased the Canadian dollar prices that we realized.

Price Risk Management

While the overall energy outlook remains generally bullish long term, there remains uncertainty as to the direction prices might move for the remainder of 2007. Natural gas prices have the potential to fall during the summer of 2007 given current levels of inventory, aggressive drilling in the U.S. and increased liquefied natural gas imports to North America. Current forecasts for a hot summer and an active hurricane season along with the potential for lower Canadian production could offset these risks. With respect to crude oil prices, global supply and demand are well balanced however geopolitical events continue to strongly influence prices.

We have developed a price risk management framework to respond to the volatile price environment in a prudent manner. Consideration is given to our overall financial position together with the economics of our acquisitions and capital development program. Consideration is also given to the upfront costs of our risk management program as we seek to limit our exposure to price downturns while maintaining participation should commodity prices increase.

Given our price risk management framework we have entered into additional commodity contracts during the first quarter of 2007. Considering all of the financial contracts transacted to date we have protected a portion of our natural gas and crude oil sales for the period April 2007 through December 2008. We have also entered into electricity contracts for the period April 2007 through September 2008 to protect against rising electricity costs in the Alberta power market. See Note 9 for a detailed list of our current price risk management positions.

The following is a summary of the physical and financial contracts in place at April 26, 2007 as a percentage of our forecasted net production volumes:

	Natural Gas (CDN$/Mcf)		Crude Oil (US$/bbl)	
	April 1, 2007 - October 31, 2007	November 1, 2007 - March 31, 2008	January 1, 2007 - December 31, 2007	January 1, 2008 - December 31, 2008
Floor Protection				
Price (puts)	$ 7.32	$ 8.60	$ 68.93	$ 67.00
% (net of royalties)	32%	10%	33%	3%
Upside Capped				
Price (calls)	$ 9.07	$ 11.05	$ -	$ 77.00
% (net of royalties)	28%	10%	-%	3%
Fixed Price				
(swaps)	$ 7.58	$ 8.70	$ 66.24	$ -
% (net of royalties)	13%	2%	8%	-%

Based on weighted average price (before premiums), average annual production of 85,000 BOE/day and assuming a 19% royalty rate.

Accounting for Price Risk Management

During the first quarter of 2007, we experienced a loss of $25.6 million on our commodity derivative instruments compared to a $0.9 million loss in the first quarter of 2006. The $25.6 million loss experienced in the first quarter of 2007 consisted of realized cash gains of $7.9 million and non-cash losses of $33.5 million on our crude oil and natural gas contracts, compared to cash costs of $22.9 million and non-cash gains of $22.0 million during the first quarter of 2006.

The decrease in crude oil cash costs of $21.3 million is a result of the expiration of contracts that existed during the first quarter of 2006 that had ceiling prices between US$35.35/bbl and US$45.80/bbl on 4,500 bbls/day. The decrease in natural gas cash costs of $9.5 million is the result of lower natural gas prices experienced during the first quarter of 2007 combined with fewer natural gas contracts outstanding compared to same period in 2006.

At March 31, 2007 the fair value of our commodity derivative instruments, net of premiums, was a loss position of $9.9 million and recorded on our balance sheet as a deferred financial liability. In comparison at December 31, 2006 the fair value of our commodity derivative instruments was a gain position of $23.6 million and recorded on our balance sheet as a deferred financial asset. This change in fair value (an unrealized loss on commodity derivative instruments of $33.5 million) reflects an increase in forward prices over this time period. As the forward markets for natural gas and crude oil fluctuate, and new contracts are executed and existing contracts are realized, changes in fair value are reflected as a non-cash charge or increase to earnings. See Note 3 for details.

The following table summarizes the effects of our commodity derivative instruments on income for the periods ended March 31, 2007 and 2006.

Risk Management (Gains)/Losses ($ millions, except per unit amounts)	Three months ended March 31, 2007		Three months ended March 31, 2006	
Cash (gains)/ losses:				
Crude oil	$ (8.4)	$(2.63)/bbl	$ 12.9	$ 4.00/bbl
Natural Gas	0.5	$ 0.02/Mcf	10.0	$ 0.41/Mcf
Total Cash (gains)/losses	$ (7.9)	$(1.01)/BOE	$ 22.9	$ 2.98/BOE
Non-cash (gains)/losses:				
Change in fair value - financial contracts	$ 33.5	$ 4.32/BOE	$ (40.3)	$(5.24)/BOE
Amortization of deferred financial assets	-	$ -/BOE	18.3	$ 2.38/BOE
Total Non-cash (gains)/losses	$ 33.5	$ 4.32/BOE	$ (22.0)	$(2.86)/BOE

Total losses	$ 25.6	$ 3.31/BOE	$ 0.9	$ 0.12/BOE

Revenues

Crude oil and natural gas revenues for the three months ended March 31, 2007 were $380.0 million ($385.9 million, net of $5.9 million of transportation costs) compared to $401.7 million ($407.8 million, net of $6.1 million of transportation costs) for the same period in 2006. The decrease of $21.7 million, or 5%, is primarily due to lower natural gas prices, partially offset by higher crude oil prices and natural gas volumes.

Analysis of Sales

Revenue(1) ($ millions)	Crude oil	NGLs	Natural Gas	Total
Quarter ended March 31, 2006	$ 178.1	$ 20.1	$ 203.5	$ 401.7
Price variance(1)	6.6	(2.7)	(28.4)	(24.5)
Volume variance	(1.4)	0.5	3.7	2.8
Quarter ended March 31, 2007	$ 183.3	$ 17.9	$ 178.8	$ 380.0

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

Other Income

Other income for the three months ended March 31, 2007 was $14.2 million compared to $1.1 million for the first quarter of 2006. During the first quarter of 2007 we sold certain marketable securities which resulted in a gain of $14.1 million. These marketable securities were historically recorded in other current assets at a cost of $2.4 million.

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three months ended March 31, 2007 royalties decreased to $70.6 million from $80.0 million during 2006, or to 19% from 20% of oil and gas sales, net of transportation costs, respectively. The decrease is consistent with the lower natural gas prices during the first quarter of 2007 compared to the same period in 2006.

For 2007 we expect royalties to remain at approximately 19% of oil and gas sales, net of transportation costs, however this may change as a result of the Alberta government's stated intention to review the oil and gas royalty regime. Alberta royalties represented approximately 70% of total royalties incurred during the first quarter of 2007.

Operating Expenses

Operating expenses for the three months ended March 31, 2007 were $8.53/BOE or $66.0 million, representing a 13% increase over $7.57/BOE in the first quarter of 2006 and slightly higher than our annual guidance of $8.45/BOE. Operating costs have increased primarily in the areas of repairs

and maintenance, well servicing and labour due to inflationary pressures and certain unanticipated expenses such as $1.8 million to repair and replace pipelines in our non-operated Mitsue area.

We continue to forecast annual operating costs of approximately $8.45/BOE.

General and Administrative Expenses

General and administrative ("G&A") expenses were $17.1 million or $2.21/BOE for the first quarter of 2007 compared to $13.3 million or $1.73/BOE for the first quarter of 2006. Cash G&A expenses were $1.94/BOE in the first quarter of 2007 compared to $1.58/BOE in the first quarter of 2006. As expected, the increase was primarily compensation costs related to retaining and recruiting skilled professionals and technical staff.

For the three months ended March 31, 2007 our G&A expenses included non-cash charges for our trust unit rights incentive plan of $2.1 million or $0.27/BOE compared to $1.2 million or $0.15/BOE for the first quarter of 2006. These amounts are determined using a binomial lattice option-pricing model. The increased volatility of our trust unit price combined with the increased number of rights outstanding as a result of an increase in the number of employees, have increased the non-cash cost of the plan.

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

General and Administrative Costs

	Three months ended March 31,	
($ millions)	2007	2006
Cash	$ 15.0	$ 12.1
Trust unit rights incentive plan (non-cash)	2.1	1.2
Total G&A	$ 17.1	$ 13.3

(Per BOE)	2007	2006
Cash	$ 1.94	$ 1.58
Trust unit rights incentive plan (non-cash)	0.27	0.15
Total G&A	$ 2.21	$ 1.73

We are maintaining our guidance for G&A expenses at $2.40/BOE, including non-cash G&A costs of approximately $0.30/BOE.

Interest Expense

Interest expense increased to $8.1 million for the first quarter of 2007 from $7.9 million during the same period of 2006. The increase was due to higher average indebtedness due to the Jonah acquisition and higher interest rates offset by non-cash gains.

Due to the adoption of new accounting standards (see Notes 3 and 6), our first quarter interest expense includes a non-cash gain of $1.6 million. This non-cash gain results from the mark-to-market changes on our interest rate swaps, the mark-to-market change on the interest component on our CCIRS and the amortization of the premium on our US$175 million senior unsecured notes.

At March 31, 2007 approximately 19% of our debt was based on fixed

interest rates while 81% was floating.

Capital Expenditures

During the three months ended March 31, 2007 we spent $110.0 million on development drilling and facilities compared to $128.7 million during the same period in 2006. We achieved a 98% success rate drilling 40 net wells during the quarter focusing primarily on Bakken Oil, crude oil waterfloods and our other conventional oil and gas properties.

Our property acquisitions during the first quarter of 2007 were $63.4 million, compared to $30.0 million in 2006. The first quarter of 2007 included the Jonah acquisition for total consideration of $61.3 million. This represented a gross-overriding royalty of approximately 0.5% on about 650 producing gas wells in the Jonah natural gas field in Wyoming. Our 2006 acquisitions primarily consisted of additional interests in the Gleneath area for $11.7 million and additional interests in the Sleeping Giant project in Montana for $14.6 million.

Total net capital expenditures of $174.8 million for the first quarter of 2007 compared to $139.8 million for the first quarter of 2006 are outlined below.

	Three months ended March 31,	
Capital Expenditures ($ millions)	2007	2006
Development expenditures	$ 90.8	$ 97.7
Plant and facilities	19.2	31.0
Development Capital	110.0	128.7
Office	1.4	0.8
Sub-total	111.4	129.5
Acquisitions of oil and gas properties(1)	63.4	30.0
Dispositions of oil and gas properties(1)	-	(19.7)
Total Net Capital Expenditures	$ 174.8	$ 139.8
Total Capital Expenditures financed with cash flow	$ 35.5	$ 39.1
Total Capital Expenditures financed with debt and equity	139.3	120.2
Total non-cash consideration for 1% sale of Joslyn project	-	(19.5)
Total Net Capital Expenditures	$ 174.8	$ 139.8

(1) Net of post-closing adjustments.

Subsequent to March 31, 2007 we closed the acquisition of a 90% interest in the Kirby Oil Sands Partnership, a privately held partnership operating in the Athabasca oil sands fairway of Alberta, for total consideration of $182.5 million consisting of $127.8 million in cash and the issuance of 1.1 million trust units at a deemed price of $49.55.

We are increasing our 2007 annual guidance by $5.0 million to $415.0 million for development capital spending to reflect additional capital spending associated with our Kirby acquisition.

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

DDA&A of property, plant and equipment is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2007 DDA&A increased to $119.1 million or $15.38/BOE compared to $111.6 million or $14.52/BOE during the corresponding period in 2006. The increase in DDA&A per BOE is due to higher capital costs experienced in recent years combined with the effect of a greater share of our production attributable to our U.S. operations which has a higher depletion cost base.

No impairment of the Fund's assets existed at March 31, 2007 using year-end reserves updated for acquisitions, divestitures and management's estimates of future prices.

Asset Retirement Obligations

The following chart compares the amortization of the asset retirement costs, accretion of the asset retirement obligation, and actual site restoration costs incurred.

	Three months ended March 31,	
($ millions)	2007	2006
Amortization of the asset retirement cost	$ 3.4	$ 3.0
Accretion of the asset retirement obligation	1.7	1.5
Total Amortization and Accretion	$ 5.1	$ 4.5
Asset Retirement Obligations Settled	$ 3.3	$ 3.1

The timing of actual asset retirement costs will differ from the timing of amortization and accretion charges. Actual asset retirement costs will be incurred over the next 66 years with the majority between 2036 and 2045. For accounting purposes, the asset retirement cost is amortized using a unit-of-production method based on proved reserves before royalties while the asset retirement obligation accretes until the time the obligation is settled.

Taxes

Future Income Taxes

Future income taxes arise from differences between the accounting and tax bases of the operating companies' assets and liabilities. Net income of the operating companies and the tax recovery fluctuate based on the royalty and interest payments to the Fund. Therefore, the future income tax that is recorded on the balance sheet is expected to be recovered through earnings over time.

For the three months ended March 31, 2007 a future income tax recovery of $23.7 million was recorded in income compared to a future income tax recovery of $1.7 million during the same period in 2006. The increase is due to greater taxable income being transferred through interest and royalties to the Fund and the consequential impact of the change in accounting policy (see Note 2 for details).

Current Income Taxes

In our current structure, payments are made between the operating entities and the Fund which ultimately transfers both income and future income tax liability to our unitholders. As a result, no cash income taxes have been

paid by our Canadian operating entities.

For the three months ended March 31, 2007 our U.S. operations incurred taxes (income and withholding) in the amount of $2.0 million compared to $3.9 million for the same period in 2006. The amount of current taxes recorded throughout the year is dependant upon the timing of both capital expenditures and repatriation of funds to Canada. Although U.S. taxes as a percentage of cash flow were lower in the first quarter, we expect the current income and withholding taxes to average approximately 15% of cash flow from U.S. operations in 2007 assuming all funds are repatriated to Canada after U.S. development capital spending.

Net Income

Net income for the first quarter of 2007 was $107.9 million or $0.88 per trust unit compared to $127.3 million or $1.08 per trust unit for the first quarter of 2006. The $19.4 million decrease in net income was primarily due to a decrease in the combined oil and gas sales (net of transportation costs) of $21.7 million, increased risk management costs of $24.7 million, and higher operating costs and depletion expense, partially offset by a $22.0 million increase in future income tax recovery and an increase of $13.1 million in other income.

Cash Flow from Operating Activities

Cash flow for the three months ended March 31, 2007 was $193.2 million or $1.57 per trust unit compared to $189.3 million or $1.60 per trust unit for the three months ended March 31, 2006. The increase in cash flow was primarily a result of lower cash risk management costs offset in part by lower gas sales along with higher operating and G&A costs. On a per unit basis it was lower due to the issue of additional trust units associated with our acquisition activities.

Selected Financial Results

	Three months ended March 31, 2007			Three months ended March 31, 2006		
Per BOE of production (6:1)	Operating Cash Flow(1)	Non-Cash & Other Items	Total	Operating Cash Flow(1)	Non-Cash & Other Items	Total
Production per day			86,028			85,392
Weighted average sales price(2)	$ 49.08	$ -	$ 49.08	$ 52.27	$ -	$ 52.27
Royalties	(9.12)	-	(9.12)	(10.40)	-	(10.40)
Commodity derivative instruments	1.01	(4.32)	(3.31)	(2.98)	2.86	(0.12)
Operating costs	(8.55)	0.02	(8.53)	(7.57)	-	(7.57)
General and administrative	(1.94)	(0.27)	(2.21)	(1.58)	(0.15)	(1.73)
Interest expense, net of interest income	(1.25)	0.21	(1.04)	(0.89)	-	(0.89)

Foreign exchange gain/(loss)	(0.07)	0.01	(0.06)	(0.01)	(0.01)	(0.02)
Capital taxes	(0.12)	-	(0.12)	(0.18)	-	(0.18)
Current income tax	(0.26)	-	(0.26)	(0.50)	-	(0.50)
Restoration and abandonment cash costs	(0.42)	0.42	-	(0.40)	0.40	-
Depletion, depreciation, amortization and accretion	-	(15.38)	(15.38)	-	(14.52)	(14.52)
Future income tax recovery	-	3.06	3.06	-	0.22	0.22
Gain on sale of marketable securities(3)	-	1.82	1.82	-	-	-
Total per BOE	$ 28.36	$(14.43)	$ 13.93	$ 27.76	$(11.20)	$ 16.56

(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, 2007 and 2006.

(CDN$ millions, except per unit amounts)	Three months ended March 31, 2007			Three months ended March 31, 2006		
	Canada	U.S.	Total	Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	266,050	9,664	275,714	265,354	5,411	270,765
Crude oil (bbls/day)	25,330	10,237	35,567	26,339	9,514	35,853
Natural gas liquids (bbls/day)	4,509	-	4,509	4,411	-	4,411
Total Daily Sales (BOE/day)	74,180	11,848	86,028	74,976	10,416	85,392
Pricing(1)						
Natural gas (per Mcf)	$ 7.21	$ 7.29	$ 7.21	$ 8.32	$ 8.61	$ 8.33
Crude oil (per bbl)	54.94	62.99	57.26	51.69	64.93	55.20

Natural gas liquids (per bbl)	44.09	-	44.09	50.57	-	50.57
Capital Expenditures						
Development capital and office	$ 73.6	$ 37.8	$ 111.4	$ 102.0	$ 27.5	$ 129.5
Acquisitions of oil and gas properties	2.1	61.3	63.4	15.4	14.6	30.0
Dispositions of oil and gas properties	-	-	-	(19.7)	-	(19.7)
Revenues						
Oil and gas sales(1)	$ 315.6	$ 64.4	$ 380.0	$ 341.9	$ 59.8	$ 401.7
Royalties	(57.9)	(12.7)(2)	(70.6)	(68.6)	(11.4)(2)	(80.0)
Financial contracts	(25.6)	-	(25.6)	(0.9)	-	(0.9)
Expenses						
Operating	$ 63.9	$ 2.1	$ 66.0	$ 56.5	$ 1.7	$ 58.2
General and adminis-trative	14.8	2.3	17.1	12.5	0.8	13.3
Depletion, depreciation, amortization and accretion	91.5	27.6	119.1	85.7	25.9	111.6
Current income taxes	-	2.0	2.0	-	3.9	3.9

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

Quarterly Financial Information

Oil and gas sales, for the first quarter of 2007 increased over the fourth quarter of 2006 as natural gas prices began to increase. Overall oil and gas sales increased during 2005 due to increased crude oil production and higher commodity prices, but decreased during 2006 as a result of softening natural gas prices throughout the year. Net income has been affected by fluctuating commodity prices and risk management costs, the fluctuating Canadian dollar, higher operating and G&A costs, changes in future tax provisions as well as changes to accounting policies adopted during 2005 and 2007. Furthermore, changes in the fair value of our commodity derivative instruments along with changes in fair value of other financial instruments cause net income to fluctuate between quarters.

Quarterly Financial Information
($ millions, except per trust unit amounts)

Net Income per trust unit

	Oil and Gas Sales(1)	Net Income	Basic	Diluted
2007				
First quarter	$ 380.0	$ 107.9	$ 0.88	$ 0.87
2006				
Fourth Quarter	$ 369.5	$ 110.2	$ 0.90	$ 0.89
Third Quarter	398.0	161.3	1.31	1.31
Second Quarter	403.5	146.0	1.19	1.19
First Quarter	401.7	127.3	1.08	1.07
Total	$ 1,572.7	$ 544.8	$ 4.48	$ 4.47
2005				
Fourth Quarter	$ 503.2	$ 150.9	$ 1.29	$ 1.28
Third Quarter	398.7	107.1	0.97	0.97
Second Quarter	320.0	108.8	1.04	1.04
First Quarter	301.8	65.2	0.63	0.62
Total	$ 1,523.7	$ 432.0	$ 3.96	$ 3.95

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

Liquidity and Capital Resources

Sustainability of our Distributions and Asset Base

As an oil and gas trust we have a declining asset base and therefore rely on ongoing development activities and acquisitions to replace production and add additional reserves. Our future oil and natural gas production and reserves are highly dependent on our success in exploiting our asset base and acquiring 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 will 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 the amount of cash distributions may be reduced.

Distribution Policy

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

At December 31, 2006 we changed our methodology for calculating payout ratio to: cash distributions to unitholders divided by cash flow from operating activities (after changes in non-cash working capital) as presented on our Consolidated Statements of Cash Flows. As a result, fluctuations in non-

cash changes in operating working capital will continue to impact our payout ratio from quarter to quarter.

Although we intend to continue to make cash distributions to our unitholders, these distributions are not guaranteed.

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 2007 cash distributions of $157.7 million were funded entirely through cash flow of $193.2 million. Our payout ratio, which is calculated as cash distributions divided by cash flow, was 82% for the three months ended March 31, 2007 compared to 79% for the same period in 2006. Cash distributions for the first quarter of 2007 were higher as a result of the 4.25 million additional units we issued on April 10, 2007 and the 1.1 million units issued in conjunction with our acquisition of Kirby. Although the additional units were issued subsequent to March 31, 2007 these units were eligible to receive the distribution announced in March for unitholders of record at April 10, 2007.

After consideration of cash distributions, the balance of our first quarter cash flow of $35.5 million was used to fund approximately 32% of our $110.0 million development capital expenditures. The balance of our development capital expenditures and our property acquisitions (which primarily related to the Jonah acquisition of $61.3 million), were financed initially through debt and subsequently through our equity issue of $210.6 million which closed April 10, 2007. As a result, our debt levels were higher throughout the first quarter of 2007 and at March 31, 2007 compared to the previous year.

In aggregate, our 2007 first quarter cash distributions of $157.7 million and our development capital of $110.0 million totaled $267.7 million, or approximately 139% of our cash flow of $193.2 million. We rely on access to capital markets to the extent cash distributions and net capital expenditures exceed cash flow. Over the long term we would expect to support our distributions and capital expenditures with our cash flow; however, we would continue to fund acquisitions and growth through additional debt and equity. There will be years, especially when we are investing capital in opportunities that do not immediately generate cash flow (such as our Joslyn and Kirby oil sands projects) that this relationship will vary. In the oil and gas sector, because of the nature of reserve reporting, the natural reservoir declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Therefore we do not disclose maintenance capital separate from development capital spending.

For the three months ended March 31, 2007 our cash distributions exceeded our net income by $49.8 million (2006 - $22.9 million). Net income includes $129.0 million of non-cash items (2006 - $89.1 million) that do not impact our cash flow. 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 commodity price environment. Future income taxes can fluctuate from period to period as a result of changes in tax rates, or based on the royalty, interest and dividends from our operating subsidiaries to the Fund, all of which are not indicative of the productive capacity of our entity. 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, 2007	2006
Cash flow from operating activities:	$ 193.2	$ 189.3
Use of cash flow:		
Cash distributions	$ 157.7	$ 150.2
Capital expenditures	35.5	39.1
	$ 193.2	$ 189.3
Excess of cash flow over cash distributions	$ 35.5	$ 39.1
Net income	$ 107.9	$ 127.3
Shortfall of net income over cash distributions	$ (49.8)	$ (22.9)
Cash distributions per weighted average trust unit	$ 1.28	$ 1.27
Payout ratio(1)	82%	79%

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

Long-Term Debt

Overall long-term debt at March 31, 2007 was $717.0 million, an increase of $37.2 million from December 31, 2006. With the adoption of the financial instrument accounting standards (see Note 2), on January 1, 2007 we adjusted the carrying value of our US$175 million senior unsecured notes to fair value of $208.2 million from their previous carrying value of $268.3 million, a decrease of $60.1 million. Subsequent to this adoption entry, our total long term debt increased by approximately $97.3 million from December 31, 2006.

Long-term debt at March 31, 2007 is comprised of $448.9 million of bank indebtedness and $268.1 million of senior unsecured notes. Our debt levels are higher at March 31, 2007 compared to March 31, 2006 as a result of an equity issue in March 2006 which closed prior to the end of the first quarter. In comparison our 2007 equity issue closed subsequent to the end of the quarter. We continue to maintain a conservative balance sheet with a long-term debt to trailing cash flow ratio of 0.8 times as demonstrated below:

Financial Leverage and Coverage	March 31, 2007	December 31, 2006
Long-term debt to trailing cash flow	0.8x	0.8x
Cash flow to interest expense	26.8x	26.8x
Long-term debt to long-term debt plus equity	21%	20%

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

There has been no change to our $850 million bank credit facility or our senior unsecured notes during the quarter. 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 operating companies to make payments to the Fund and consequently the Fund's ability to make distributions to the unitholders may be restricted. At March 31, 2007 we are in compliance with our debt covenants; the most restrictive of which allows us to have a ratio of long term debt to trailing cash flow of 3 to 1. Refer to our 2006 Annual Information Form 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 6.

We anticipate that we will continue to have adequate liquidity to fund planned development capital spending during 2007 through a combination of cash flow retained by the business and debt. A portion of our $415.0 million development capital budget for 2007 is discretionary and could be revised downward in the event of a commodity price downturn or similar economic event.

Trust Unit Information

We had 123,434,000 trust units outstanding at March 31, 2007 compared to 122,232,000 trust units at March 31, 2006 and 123,151,000 at December 31, 2006. The weighted average basic number of trust units outstanding during the first quarter of 2007 was 123,282,000 (2006 - 118,221,000).

During the three months ended March 31, 2007 283,000 trust units (2006 - 323,000) were issued pursuant to the Trust Unit Monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP") and the trust unit rights plan. This resulted in $13.0 million (2006 - $13.4 million) of additional equity to the Fund. For further details see Note 8.

Canadian and U.S. Taxpayers

Enerplus estimates that approximately 95% of cash distributions paid to Canadian unitholders and 90% of cash distributions paid to U.S. unitholders will be taxable and the remaining 5% and 10% respectively will be treated as a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions that are dependent upon production, commodity prices and cash flow experienced throughout the year.

For U.S. taxpayers the taxable portion of the cash distribution is considered to be a dividend for U.S. tax purposes. For most U.S. taxpayers this should be a "Qualified Dividend" eligible for the reduced tax rate. This preferential rate of tax for "Qualified Dividends" is set to expire at the end of 2010. On March 24, 2007, Bill 1672 was introduced into the U.S. House of Representatives which, if enacted as presented, would make dividends from Canadian income funds such as Enerplus ineligible for treatment as a "Qualified Dividend". The dividends would then become a "non-qualified dividend from a foreign corporation" subject to the normal rates of tax commencing with dividends received after the date of enactment. The proposed bill still requires the approval of the House of Representatives, the Senate and the President prior to it being enacted. Therefore, we are unable to determine when or even if the bill will become enacted as presented.

In April 2007, Enerplus estimated its non-resident ownership to be approximately 73%.

RECENT CANADIAN ACCOUNTING PRONOUNCEMENTS

CICA Section 3862 - Financial Instruments - Disclosures

This standard requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks.

This standard is effective for January 1, 2008 and will result in additional disclosures for our financial instruments.

CICA Section 3863 - Financial Instruments - Presentation

This standard establishes presentation guidelines for financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset.

This standard is effective for January 1, 2008 and should have a minimal impact on our reporting.

DISCLOSURE CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the quarter ended March 31, 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

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

FORWARD-LOOKING STATEMENTS

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

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

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon.

Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; unanticipated operating results or production declines; changes in tax or environmental laws or royalty rates; increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserves volumes; limited, unfavourable or no access to capital markets; increased costs; the impact of competitors; and certain other risks detailed from time to time in the Fund's public disclosure documents including, without limitation, those risks identified in this MD&A and in the Fund's annual information form.

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

CONSOLIDATED BALANCE SHEETS

(CDN$ thousands) (Unaudited)	March 31, 2007	December 31, 2006
Assets		
Current assets		
Cash	$ 94	$ 124
Accounts receivable	190,622	175,454
Deferred financial assets (Note 3)	1,441	23,612
Other current	5,083	6,715
	197,240	205,905
Property, plant and equipment (Note 4)	3,777,665	3,726,097
Goodwill	219,726	221,578
Other assets	47,469	50,224
	$ 4,242,100	$ 4,203,804
Liabilities		
Current liabilities		
Accounts payable	$ 279,556	$ 284,286
Distributions payable to unitholders	54,092	51,723
Deferred financial credits (Note 3)	76,857	-
	410,505	336,009
Long-term debt (Note 6)	716,954	679,774
Future income taxes	304,421	331,340
Asset retirement obligations (Note 5)	124,095	123,619
	1,145,470	1,134,733
Equity		
Unitholders' capital (Note 8)	3,728,257	3,713,126
Accumulated deficit	(1,026,607)	(971,085)
Accumulated other comprehensive income (Note 2)	(15,525)	(8,979)
	2,686,125	2,733,062

	$ 4,242,100	$ 4,203,804

CONSOLIDATED STATEMENTS OF ACCUMULATED DEFICIT

(CDN$ thousands) (Unaudited)	Three months ended March 31, 2007	2006
Accumulated income, December 31	$ 1,952,960	$ 1,408,178
Adjustment for adoption of financial instruments standards (Note 2)	(5,724)	-
Revised opening balance, beginning of period	1,947,236	1,408,178
Net income	107,873	127,292
Accumulated income, end of period	$ 2,055,109	$ 1,535,470
Accumulated cash distributions, beginning of year	$(2,924,045)	$(2,309,705)
Cash distributions	(157,671)	(150,245)
Accumulated cash distributions, end of period	$(3,081,716)	$(2,459,950)
Accumulated deficit, end of period	$(1,026,607)	$ (924,480)

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

(CDN$ thousands) (Unaudited)	Three months ended March 31, 2007	2006
Balance, beginning of period	$ (8,979)	$ (15,568)
Transition adjustments (Note 2):		
Cash flow hedges	660	-
Marketable securities available for sale	14,252	-
Other comprehensive income	(21,458)	3,059
Balance, end of period	$ (15,525)	$ (12,509)

CONSOLIDATED STATEMENTS OF INCOME

(CDN$ thousands except per trust unit amounts) (Unaudited)	Three months ended March 31, 2007	2006

Revenues		
Oil and gas sales	$ 385,871	$ 407,838
Royalties	(70,647)	(79,971)
Commodity derivative instruments (Notes 3 and 9)	(25,606)	(895)
Other income	14,160	1,068
	303,778	328,040
Expenses		
Operating	66,030	58,165
General and administrative (Note 8)	17,110	13,305
Transportation	5,864	6,112
Interest on long-term debt	8,115	7,896
Foreign exchange loss (Note 7)	482	154
Depletion, depreciation, amortization and accretion	119,091	111,551
	216,692	197,183
Income before taxes	87,086	130,857
Capital taxes	918	1,435
Current taxes	2,047	3,862
Future income tax recovery	(23,752)	(1,732)
Net Income	$ 107,873	$ 127,292
Net income per trust unit		
Basic	$ 0.88	$ 1.08
Diluted	$ 0.87	$ 1.07
Weighted average number of trust units outstanding (thousands)		
Basic	123,282	118,221
Diluted	123,363	118,725

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended March 31,	
(CDN$ thousands) (Unaudited)	2007	2006
Net income	$ 107,873	$ 127,292
Other comprehensive income, net of tax:		
Unrealized losses on marketable securities, net of tax of $1,305	(3,156)	-
Realized gains on marketable securities included in net income, net of tax of $2,839	(11,654)	-
Gains and losses on derivatives designated as hedges in prior periods included in net income, net of tax of $50	(204)	-

Change in cumulative translation adjustment	(6,444)	3,059
Other comprehensive income	(21,458)	3,059
Comprehensive income (Note 2)	$ 86,415	$ 130,351

CONSOLIDATED STATEMENTS OF CASH FLOWS

(CDN$ thousands) (Unaudited)	Three months ended March 31, 2007	2006
Operating Activities		
Net income	$ 107,873	$ 127,292
Non-cash items add/(deduct):		
Depletion, depreciation, amortization and accretion	119,091	111,551
Change in fair value of derivative instruments (Note 3)	34,847	(21,985)
Unit based compensation (Note 8)	2,111	1,187
Foreign exchange on translation of senior notes (Note 7)	(2,882)	65
Future income tax	(23,752)	(1,732)
Amortization of senior notes premium	(169)	-
Reclassification adjustments from AOCI to net income	(204)	-
Gain on sale of marketable securities	(14,055)	-
Asset retirement obligations settled (Note 5)	(3,314)	(3,063)
	219,546	213,315
Increase in non-cash operating working capital	(26,365)	(24,034)
Cash flow from operating activities	193,181	189,281
Financing Activities		
Issue of trust units, net of issue costs (Note 8)	13,020	253,680
Cash distributions to unitholders	(157,671)	(150,245)
Increase/(decrease) in bank credit facilities	100,342	(132,854)
Decrease in non-cash financing working capital	2,369	2,000
Cash flow from financing activities	(41,940)	(27,419)
Investing Activities		
Capital expenditures	(111,354)	(129,560)
Property acquisitions	(63,423)	(30,027)
Property dispositions	-	189
Proceeds on sale of marketable securities	16,467	-
Decrease/(increase) in non-cash investing working capital	6,130	(11,433)

Cash flow from investing activities	(152,180)	(170,831)
Effect of exchange rate changes on cash	909	141
Change in cash	(30)	(8,828)
Cash, beginning of period	124	10,093
Cash, end of period	$ 94	$ 1,265

Supplementary Cash Flow Information		
Cash income taxes paid	$ 3,241	$ 254
Cash interest paid	$ 6,086	$ 4,523

ENERPLUS RESOURCES FUND
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular amounts in thousands of Canadian dollars and thousands of units except per unit amounts) (Unaudited)

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, 2006, except as identified in Note 2. 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, 2006. The disclosures provided below are incremental to those included in the 2006 annual consolidated financial statements of the Fund.

2. CHANGES IN ACCOUNTING POLICIES

Financial Instruments
Effective January 1, 2007, the Fund adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Handbook section 1530, Comprehensive Income, Handbook Section 3855, Financial Instruments - Recognition and Measurement, and Handbook Section 3865, Hedges. These standards were adopted prospectively pursuant to their respective adoption provisions, and therefore there is no effect on prior periods.

Comprehensive Income

CICA Handbook section 1530 introduces comprehensive income, which consists of net income and other comprehensive income ("OCI"). OCI represents changes in equity during a period arising from transactions and other events with non-owner sources and includes unrealized gains and losses on marketable securities classified as available-for-sale along with unrealized foreign currency translation gains or losses arising from self-sustaining foreign operations, among other things. The Consolidated Statements of Comprehensive Income include a calculation of comprehensive income for the first quarter of 2007, while the cumulative changes in OCI are included in the Statements of Accumulated Other Comprehensive Income (AOCI).

Financial Instruments - Recognition and Measurement

CICA Handbook section 3855 establishes the criteria for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. Under this standard, all financial instruments are required to be measured at fair value on recognition except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as held-for-trading, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities.

Financial assets and financial liabilities classified as held-for-trading are measured at fair value with changes in fair value recognized in net income. Financial assets classified as loans and receivables along with financial liabilities classified as other liabilities are measured at amortized cost using the effective interest rate method. Financial assets classified as available-for-sale are measured at fair value with changes in fair value recognized in OCI. Investments in equity instruments classified as available-for-sale that do not have a quoted price in an active market are measured at cost. Transaction costs or fees attributable to the acquisition, issue, or disposal of a financial asset or liability are expensed immediately to net income.

Derivative instruments are recorded on the consolidated balance sheets at fair value, including those derivatives that are embedded in financial or non-financial contracts that are not closely related to the host contracts. Changes in the fair values of derivative instruments are recognized in net income with the exception of derivatives that are designated as effective cash flow hedges. Refer to the Hedges section for further detail.

Hedges

CICA Handbook section 3865 specifies the criteria and method of accounting for each of the designated hedging strategies.

When hedge accounting is discontinued for a cash flow hedge, the amounts previously recognized in AOCI are reclassified to net income over the remaining term of the derivative instrument.

When hedge accounting is discontinued for a fair value hedge, the carrying value of the hedged item is no longer adjusted. Any difference between the carrying value and the face value or principle amount of the hedged item is amortized to net income over the remaining term of the original hedging relationship using the effective interest method.

Impact upon Adoption of Sections 1530, 3855 and 3865

As a result of the adoption of these standards on January 1, 2007 the Fund elected to stop designating its interest rate and electricity swaps as cash flow hedges and recorded these items on the consolidated balance sheet at their fair values with the offset recorded to opening accumulated other comprehensive income. In addition, the Fund elected to stop designating its cross currency and interest rate swap ("CCIRS") as a fair value hedge and recorded the CCIRS on the consolidated balance sheet at fair value with the offset recorded to opening accumulated deficit. In conjunction, the underlying US$175,000,000 senior unsecured notes were

recorded at fair value with the offset recorded to opening accumulated deficit.

The Fund's investments in marketable securities have been classified as available-for-sale and were therefore recorded on the consolidated balance sheet at fair value with the offset recorded to opening AOCI.

Deferred charges of $1,523,000 associated with issuance of the senior unsecured notes were recorded to the opening accumulated deficit.

Amounts previously recorded in the cumulative translation adjustment were reclassified into opening AOCI. Our prior year comparative statements have been restated to reflect this change.

The Fund has recorded the following transition adjustments as of January 1, 2007 in the Consolidated Financial Statements: (a) an increase of $1,494,000 to deferred financial assets to record the electricity swaps at fair value; (b) an increase to other current assets of $14,493,000 to record publicly traded marketable securities at fair value; (c) an increase of $1,708,000 to other assets, consisting of $3,231,000 to record publicly traded marketable securities at fair value less $1,523,000 to write-off the deferred charges associated with the issuance of the senior unsecured notes; (d) an increase of $65,675,000 to deferred financial credits to record the CCIRS and interest rates swaps at fair value; (e) a decrease to long-term debt of $60,111,000 to record the US$175,000,000 senior unsecured note at fair value; (f) an increase to future income taxes of $ 2,943,000 to reflect the tax impact of the adoption entries; (g) an increase of $5,724,000, net of taxes, to the opening accumulated deficit; (h) recognition in AOCI of $14,912,000, net of taxes, related to the net gains on marketable securities classified as available-for-sale along with the fair value of the interest rate and power swaps formerly designated as cash flow hedges. In addition, the Fund reclassified to AOCI $8,979,000 of net unrealized foreign currency losses that were previously presented as a separate item in equity. These transition adjustments are summarized below.

Impact of transition adjustment on selected consolidated balance sheets line items:

(CDN$ thousands)	Transition adjustment as at January 1, 2007
Deferred financial assets	$ 1,494
Other current assets	14,493
Other assets	1,708
Deferred credits	65,675
Long-term debt	(60,111)
Future income taxes	2,943
Accumulated deficit	(5,724)
Cumulative translation adjustment	8,979
Accumulated other comprehensive income	5,933

As a result of these changes, net income increased by $864,000 ($1,221,000 before future income taxes of $357,000) for the first quarter of 2007. Basic and diluted per trust unit calculations for the three months ended March 31, 2007 both increased by $0.01 as a result of the new standards.

3. DEFERRED FINANCIAL ASSETS AND CREDITS

The deferred financial assets and credits result from recording our derivative financial instruments at fair value. The deferred financial credit relating to crude oil and natural gas instruments of $9,870,000 at March 31, 2007 consists of the fair value of the financial instruments of $9,568,000 less the related deferred premiums of $19,438,000.

($ thousands)	Interest Rate Swap	Cross Currency Interest Rate Swaps	Electricity Swaps
Deferred financial assets/ (credits) as at December 31, 2006	$ -	$ -	$ -
Adoption of financial instruments standards(1)	(673)	(65,002)	1,494
Change in fair value	181(2)	(1,493)(3)	(53)(4)
Deferred financial assets/ (credits) as at March 31, 2007	$ (492)	$(66,495)	$ 1,441

($ thousands)	Commodity Derivative Instruments	Total
Deferred financial assets/ (credits) as at December 31, 2006	$ 23,612	$ 23,612
Adoption of financial instruments standards(1)	-	(64,181)
Change in fair value	(33,482)(5)	(34,847)
Deferred financial assets/ (credits) as at March 31, 2007	$ (9,870)	$(75,416)

(1) The adoption of the financial instruments standards on January 1, 2007 resulted in a decrease to the deferred financial assets balance. See Note 2 for further details.
(2) Recorded in interest expense.
(3) Recorded in foreign exchange expense (loss of $2,776) and interest expense (gain of $1,283).
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments (see below).

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

Commodity Derivative Instruments ($ thousands)	Three months ended March 31, 2007	2006
Change in fair value	$ 33,482	$ (40,281)

Amortization of deferred financial assets	-	18,296
Realized cash (gains) / costs, net	(7,876)	22,880
Net cost (cash and non-cash) of commodity derivative instruments	$ 25,606	$ 895

4. PROPERTY, PLANT AND EQUIPMENT

($ thousands)	March 31, 2007	December 31, 2006
Property, plant and equipment	$ 6,022,328	$ 5,855,511
Accumulated depletion, depreciation and accretion	(2,244,663)	(2,129,414)
Net property, plant and equipment	$ 3,777,665	$ 3,726,097

Capitalized development G&A of $4,019,000 (2006 - $3,208,000) is included in property, plant and equipment ("PP&E") for the three months ended March 31, 2007. Excluded from PP&E for the purpose of the depletion and depreciation calculation is $90,678,000 (2006 - $49,328,000) related to the Joslyn development project that has not yet commenced commercial production.

5. ASSET RETIREMENT OBLIGATIONS

The following table reconciles the Fund's asset retirement obligations:

($ thousands)	Three months ended March 31, 2007	Year ended December 31, 2006
Asset retirement obligations, beginning of period	$ 123,619	$ 110,606
Changes in estimates	1,645	12,757
Acquisition and development activity	476	5,574
Dispositions	-	5) (4
Asset retirement obligations settled	(3,314)	(11,514)
Accretion expense	1,669	6,241
Asset retirement obligations, end of period	$ 124,095	$ 123,619

6. LONG-TERM DEBT

($ thousands)	March 31, 2007	December 31, 2006
Bank credit facilities(a)	$ 448,862	$ 348,520
Senior notes(b)		
US$175 million (issued June 19, 2002)	205,835	268,328
US$54 million (issued October 1, 2003)	62,257	62,926

Total long-term debt	$ 716,954	$ 679,774

(a) Unsecured Bank Credit Facility

Enerplus has an $850,000,000 unsecured covenant based three year term facility with a bullet payment required at the end of the term, which is currently November 18, 2009. The facility may be extended each year so that Enerplus retains the three year term and extends its payment obligation accordingly. Various borrowing options are available under the facility including prime rate based advances and bankers' acceptance loans. This facility carries floating interest rates that are expected to range between 55.0 and 110.0 basis points over bankers' acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items. The effective interest rate on the facility for the three months ended March 31, 2007 was 4.9% (2006 - 4.2%).

(b) Senior Unsecured Notes

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 subject to fluctuations in foreign exchange rates and are translated into Canadian dollars using the period end foreign exchange rate.

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%.

On January 1, 2007 in conjunction with the adoption of CICA Sections 3855 and 3865, the Fund elected to stop designating the CCIRS as a fair value hedge on the US$175,000,000 senior notes. As a result, the Fund recorded the senior notes at their fair value of US$178,681,000 (CDN $208,217,000) with the offset to opening accumulated deficit. In addition, the Fund recorded a liability of $65,002,000 with the offset to opening accumulated deficit, which represented the fair value of the CCIRS. The premium amount of US$3,681,000, representing the difference between the January 1, 2007 fair value and the face amount of the senior notes, will be amortized to net income over the remaining term of the notes using the effective interest method. The effective interest rate over the remaining term of the senior notes is 6.16%. The senior notes are carried at amortized cost and are translated into Canadian dollars using the period end foreign exchange rate. At March 31, 2007 the amortized cost of the US$175,000,000 senior notes was US$178,537,000.

7. FOREIGN EXCHANGE

	Three months ended March 31,

($ thousands)	2007	2006
Unrealized foreign exchange (gain)/loss on translation of U.S. dollar denominated senior notes	$ (2,882)	$ 65
Cross currency interest rate swap	2,776	-
Realized foreign exchange loss	588	89
Foreign exchange loss	$ 482	$ 154

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

8. FUND CAPITAL

(a) Unitholders' Capital

Trust Units
Authorized: Unlimited number of trust units

Issued: (thousands)	Three months ended March 31, 2007 Units	Amount	Year ended December 31, 2006 Units	Amount
Balance before Contributed Surplus, beginning of period	123,151	$ 3,706,821	117,539	$ 3,407,567
Issued for cash:				
Pursuant to public offerings	-	-	4,370	240,287
Pursuant to rights plans	24	820	640	22,974
Trust unit rights incentive plan (non-cash) - exercised	-	452	-	3,065
DRIP(*), net of redemptions	259	12,200	602	32,928
	123,434	3,720,293	123,151	3,706,821
Contributed Surplus (Trust Unit Rights Plan)	-	7,964	-	6,305
Balance, end of period	123,434	$ 3,728,257	123,151	$ 3,713,126

(*) Distribution Reinvestment and Unit Purchase Plan

Contributed surplus ($ thousands)	Three months ended March 31, 2007	Year ended December 31, 2006
Balance, beginning of period	$ 6,305	$ 3,047
Trust unit rights incentive plan (non-cash) - exercised	(452)	(3,065)
Trustunit rights incentive plan (non-cash) - expensed	2,111	6,323
Balance, end of period	$ 7,964	$ 6,305

Subsequent to the quarter ended March 31, 2007 the Fund closed an equity offering on April 10, 2007 of 4,250,000 units at a price of $49.55 per unit for gross proceeds of $210,588,000 ($200,058,000 net of issuance costs). These trust units were eligible for the April 20, 2007 cash distribution paid to unitholders of record at the close of business on April 10, 2007.

On March 20, 2006 the Fund closed an equity offering of 4,370,000 units at a price of $58.00 per unit for gross proceeds of $253,460,000 ($240,287,000 net of issuance costs).

(b) Trust Unit Rights Incentive Plan

As at March 31, 2007, a total of 3,160,000 rights pursuant to the Trust Unit Rights Incentive Plan ("Rights Plan") at an average exercise price of $48.23 were outstanding. This represents 2.6% of the total trust units outstanding of which 950,000 rights with an average exercise price of $41.22 were exercisable. Under the Rights 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, 2007 reduced the exercise price of the outstanding rights by $0.51 per trust unit effective July 2007.

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

	Three months ended March 31, 2007		Year ended December 31, 2006	
	Number of Rights (000's)	Weighted Average Exercise Price(1)	Number of Rights (000's)	Weighted Average Exercise Price(1)
Trust unit rights outstanding				
Beginning of period	3,079	$ 48.53	2,621	$ 42.80
Granted	182	48.86	1,473	54.49
Exercised	(24)	34.21	(640)	35.94
Cancelled	(77)	50.17	(375)	46.35
End of period	3,160	48.23	3,079	48.53

Rights exercisable at the end of the period	950	$ 41.22	809	$ 39.81

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

The Fund uses a binomial option-pricing model to calculate the estimated fair value of rights under the plan. Non-cash compensation costs of $2,111,000 ($0.02 per unit) related to rights issued were charged to general and administrative expense during the three months ended March 31, 2007 (2006 - $1,187,000, $0.01 per unit).

(c) Basic and Diluted per Trust Unit Calculations

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

	Three months ended March 31,	
($ thousands)	2007	2006
Weighted average units	123,282	118,221
Dilutive impact of rights	81	504
Diluted trust units	123,363	118,725

9. FINANCIAL INSTRUMENTS

(a) Fair Value of Financial Instruments

As a result of the adoption of the new financial instrument and hedging accounting standards described in Note 2, certain financial instruments are now measured and reported on the balance sheet at fair value which were previously reported at amortized cost.

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

(b) Carrying Value and Fair Value of 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 are reported at amortized cost. At March 31, 2007 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. As at March 31, 2007 the Fund reported investments in marketable securities of publicly traded marketable securities at a fair value of $8,769,000.

Marketable securities without a quoted market price in an active market are reported at amortized cost. As at March 31, 2007 the Fund reported investments in marketable securities of private companies at an amortized cost of $38,700,000.

Marketable securities are included in other current assets or 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 as well as Distributions payable to unitholders are classified as other liabilities and are reported at amortized cost. At March 31, 2007 the carrying value of these accounts approximated their fair value.

v. Long-term debt

Bank Credit Facilities

The bank credit facilities are classified as other liabilities and are reported at amortized cost. At March 31, 2007 the carrying value of the bank credit facilities approximated their fair value.

US$54 million senior notes

The US$54,000,000 million 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, 2007 the Canadian dollar amortized cost of the senior notes was approximately $62,257,000.

US$175 million senior notes

The US$175,000,000 million senior notes, which are classified as other liabilities, are reported at amortized cost of $178,537,000 and are translated into Canadian dollars at the period end exchange rate. At March 31, 2007 the Canadian dollar amortized cost of the senior notes was approximately $205,835,000.

vi. Derivative Financial Instruments

Interest Rate Swaps

The Fund has entered into interest rate swaps on $75,000,000 of notional debt at rates varying from 4.10% to 4.61% before banking fees that are expected to range between 0.55% and 1.10%. These interest rate swaps

mature between June 2011 and January 2012. The interest rate swaps are classified as held-for-trading and are reported at fair value. At March 31, 2007 the fair value of the interest rate swaps represented a liability of $492,000. For the three months ended March 31, 2007, the change in fair value of these contracts represented an unrealized gain of $181,000.

Cross Currency Interest Rate Swap (CCIRS)

Concurrent with the issuance of the notes on June 19, 2002, the Fund entered into a CCIRS with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal 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%. The CCIRS is classified as held-for-trading and is reported at fair value. At March 31, 2007 the fair value of the CCIRS represented a liability of $66,495,000. For the three months ended March 31, 2007, the change in fair value of the CCIRS represented an unrealized loss of $1,493,000.

Crude Oil Instruments

Enerplus has entered into the following financial option contracts to reduce the impact of a downward movement in crude oil prices. These contracts are classified as held-for-trading and are reported at fair value. At March 31, 2007 the fair value of these contracts represented a liability of $1,958,000. For the three months ended March 31, 2007, the change in fair value of these contracts represented an unrealized loss of $12,880,000.

The net premium cost of the crude oil instruments entered into as of March 31, 2007 is $15,622,000.

The following table summarizes the Fund's crude oil risk management positions at April 26, 2007:

		WTI US$/bbl		
	Daily Volumes bbls/day	Sold Call	Purchased Put	Fixed Price and Swaps
Term				
April 1, 2007 - December 31, 2007				
Put	5,000	-	$ 71.00	-
Put	2,500	-	$ 68.00	-
Put	2,500	-	$ 65.70	-
Swap	2,500	-	-	$ 66.24
January 1, 2008 - December 31, 2008				
Collar(1)	750	$ 77.00	$ 67.00	-

(1) Financial contracts entered into during the first quarter of 2007.

Natural Gas Instruments

Enerplus has certain physical and financial contracts outstanding as at April 26, 2007 on its natural gas production that are detailed below. In

addition, the Fund has outstanding physical natural gas contracts that provide the Fund a premium of $0.50/Mcf on 19.4MMcf/day for April 2007 and a premium of $0.02/Mcf on 2.4MMcf/day for April through June 2007.

These contracts are classified as held-for-trading and are reported at fair value. At March 31, 2007 the fair value of these contracts represented a liability of $7,912,000. For the three months ended March 31, 2007, the change in fair value of these contracts represented an unrealized loss of $20,602,000.

The net premium cost of the financial natural gas instruments entered into as of March 31, 2007 is $3,816,000.

		AECO CDN$/Mcf			
	Daily Volumes MMcf/day	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term					
April 1, 2007 - June 30, 2007					
Put	4.7	-	$ 7.50	-	-
April 1, 2007 - October 31, 2007					
Collar	6.6	$ 10.02	$ 7.50	-	-
Collar	6.6	$ 9.00	$ 7.50	-	-
Collar	9.5	$ 9.10	$ 7.10	-	-
Collar	9.5	$ 9.15	$ 7.14	-	-
Collar	9.5	$ 9.50	$ 7.20	-	-
Costless Collar(1)	4.7	$ 8.02	$ 7.17	-	-
Costless Collar(1)	4.7	$ 8.23	$ 7.28	-	-
Costless Collar(1)	4.7	$ 8.20	$ 7.50		
3-Way option	4.7	$ 9.50	$ 7.75	$ 5.49	-
Put	4.7	-	$ 7.28	-	-
Swap	6.6	-	-	-	$ 7.60
Swap	4.7	-	-	-	$ 7.33
Swap	2.4	-	-	-	$ 7.84
Swap	2.4	-	-	-	$ 7.96
Swap(1)	7.1	-	-	-	$ 7.17
Swap(1)	2.4	-	-	-	$ 7.70
Swap(1)	2.4	-	-	-	$ 7.53
Swap(1)	2.4	-	-	-	$ 8.35
November 1, 2007 - March 31, 2008					
Collar	2.4	$ 9.95	$ 8.00	-	-
3-Way option	4.7	$ 10.50	$ 8.20	$ 5.70	-
3-Way option(1)	4.7	$ 11.61	$ 8.97	$ 6.33	-
3-Way option(2)	4.7	$ 11.61	$ 8.97	$ 6.33	-
3-Way option(2)	4.7	$ 11.08	$ 8.55	$ 6.01	-
Swap	4.7	-	-	-	$ 8.70
2007 - 2010					
Physical (escalated pricing)	2.0	-	-	-	$ 2.52

(1) Financial contracts entered into during the first quarter of 2007.

(2) Financial contracts entered into during the second quarter of 2007.

Electricity Instruments

The Fund has entered into electricity swaps that fix the price of electricity. These contracts are classified as held-for-trading and are reported at fair value. At March 31, 2007 the fair value of these contracts represented an asset of $1,441,000. For the three months ended March 31, 2007, the change in fair value of these contracts represented an unrealized loss of $53,000.

Unrealized gains or losses resulting from changes in fair value along with realized gains or losses on settlement of the electricity contracts are recognized as operating costs.

The following table summarizes the Fund's electricity management positions at April 26, 2007.

Term	Volumes MWh	Price CDN$/MWh
April 1, 2007 - December 31, 2007	5.0	$ 61.50
April 1, 2007 - December 31, 2007	4.0	$ 62.90
April 1, 2008 - September 30, 2008	4.0	$ 63.00

The Fund did not enter into any new electricity contracts in the first quarter of 2007.

10. EVENTS SUBSEQUENT TO MARCH 31, 2007

Kirby Acquisition

On April 10, 2007 the Fund closed the acquisition of a 90% interest in the Kirby Oil Sands Partnership, a privately held partnership operating in the Athabasca oil sands fairway of Alberta, for total consideration of $182,500,000 consisting of $127,750,000 in cash and the issuance of 1,104,945 trust units at a deemed price of $49.55. As part of the acquisition, Enerplus will become the managing partner and the operator of the project.

This news release contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the amount, timing and tax treatment of cash distributions to unitholders; future payout ratios; future tax treatment of income trusts such as the Fund; the volumes and estimated value of the Fund's future oil and gas reserves; the volume and product mix of the Fund's oil and gas production; future oil and natural gas prices and the Fund's commodity risk management programs; the amount of future asset retirement obligations; future liquidity and financial capacity; future results from operations, cost estimates and royalty rates; future development, exploration, 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 news release reflect several material factors and expectations and assumptions of

the Fund including, without limitation: that the Fund will continue to conduct its operations in a manner consistent with past operations; the general continuance of current industry conditions; the continuance of existing (and in certain circumstances, proposed) tax and royalty regimes; the accuracy of the estimates of the Fund's reserve volumes; and certain commodity price and other cost assumptions. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this news release are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; unanticipated operating results or production declines; changes in tax or environmental laws or royalty rates; increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserves volumes; limited, unfavourable or no access to capital markets; increased costs; the impact of competitors; and certain other risks detailed from time to time in the Fund's public disclosure documents (including, without limitation, those risks identified in this news release and in the Fund's annual information form).

The forward-looking information and statements contained in this news release speak only as of the date of this news release, 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.

Gordon J. Kerr
President & Chief Executive Officer