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20

06

First Quarter Report

Three months ended March 31, 2006

executing on the strategy

FINANCIAL & OPERATING HIGHLIGHTS

SELECTED FINANCIAL RESULTS

For the three months ended March 31,	2006	2005
Financial (000's)		
Net Income[1]	$127,292	$ 65,178
Funds Flow from Operations[2]	213,315	153,741
Cash Available for Distribution[3]	152,197	109,843
Cash Withheld for Acquisitions and Capital Expenditures	61,118	43,898
Debt Outstanding (net of cash)	525,864	562,369
Development Capital Spending	128,748	69,303
Acquisitions	30,027	1,820
Divestments	19,717	61,689
Financial per Unit		
Net Income[1]	$ 1.08	$ 0.63
Funds Flow from Operations[2]	1.80	1.47
Cash Distributed[3]	1.26	1.05
Cash Withheld for Acquisitions and Capital Expenditures	0.51	0.42
Payout Ratio	71%	71%
Selected Financial Results per BOE[4]		
Oil & Gas Revenues[5]	$ 52.27	$ 42.55
Royalties	(10.40)	(8.78)
Financial Contracts	(2.98)	(2.86)
Operating Costs	(7.57)	(6.98)
General and Administrative	(1.58)	(1.09)
Interest and Foreign Exchange	(0.90)	(0.71)
Taxes	(0.68)	(0.17)
Restoration and Abandonment	(0.40)	(0.29)
Funds Flow from Operations[2]	$ 27.76	$ 21.67
Weighted Average Number of Trust Units Outstanding (thousands)	118,221	104,269
Debt/Trailing 12 Month Funds Flow Ratio[2]	0.6x	1.0x

SELECTED OPERATING RESULTS

For the three months ended March 31,	2006	2005
Average Daily Production		
Natural gas (Mcf/day)	270,765	280,463
Crude oil (bbls/day)	35,853	27,448
NGLs (bbls/day)	4,411	4,621
Total (BOE/day) (6:1)	85,392	78,813
% Natural gas	53%	59%
Average Selling Price[5]		
Natural gas (per Mcf)	$ 8.33	$ 6.58
Crude oil (per bbl)	55.20	47.61
NGLs (per bbl)	50.57	43.80
US$ exchange rate	0.87	0.82
Net Wells Drilled	124	95
Success Rate	100%	100%

(1) See trust unit rights incentive plan discussion in Note 1
(2) See the definition of funds flow in Management's Discussion and Analysis
(3) Calculated based on distributions paid or payable each month relating to the period
(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, 2006	TSX – ERF.un (CDN$)	NYSE – ERF (US$)
High	64.36	56.05
Low	52.12	45.10
Close	58.57	50.44

2006 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 1.11

PRESIDENT'S MESSAGE

Enerplus had another strong lead-off quarter in 2006 with both record production volumes and drilling activity. Our combined oil and natural gas production for the quarter averaged 85,392 BOE/day, setting a new high for Enerplus as a result of the ongoing strength of our operations in the United States and Canada. Our development program also achieved record levels in the quarter as we participated in the drilling of 289 wells (124.3 net) with a 100% success rate. We are well on track to meet our full year 2006 capital expenditures guidance of $485 million, having spent $129 million in the first quarter. The capital program concentrated on Bakken oil in Montana, coalbed methane in Alberta, tight shallow gas in southern Alberta and Saskatchewan, and the Athabasca oil sands in northern Alberta as we remain focused on the development of our resource plays.

Cash distributions paid in the quarter to our Canadian unitholders totaled $1.26 per unit and US$1.11 per unit to our U.S. unitholders. This represents a 20% increase in distributions for Canadian unitholders and a 31% increase for U.S. unitholders over the same period last year and is a result of our increased production volumes associated with our acquisition and development activities and increased commodity prices. We were able to retain over $61 million to fund our capital development program resulting in a payout ratio of 71% for the quarter.

Throughout the first quarter realized oil prices were reasonably consistent, averaging 16% higher than prices in the first quarter of 2005. Realized natural gas prices however declined throughout the first quarter of 2006. This decline in natural gas prices is believed to be largely the result of significant gas inventory builds through the warm winter experienced in North America. Overall, we believe the long-term supply/demand balance for both commodities remains tight. Oil prices in particular are impacted by growing global demand and supply disruptions in politically volatile producing regions. In this regard, we have seen increasing oil prices on the world stage and a widening gap between the price of oil and natural gas versus historical averages. While we believe the current natural gas price weakness may prove temporary, the duration of this lower gas price environment will be dependent upon the ability of the North American supply/demand system to rebalance itself. At this point in time, there is a great deal of uncertainty around the direction prices will go, however, there do not appear to be any long-term supply solutions for either commodity.

We continue to move forward on the development of the Joslyn oil sands lease with the operator, Deer Creek Energy Ltd., a wholly-owned subsidiary of Total E&P Canada ("Total"). As mentioned in our annual report, Total filed an application for the North Mine and we commissioned an interim reserves/resources report from our independent reserve engineers. This report quantified the recoverable resource associated with the mining potential for the lease and when combined with our existing booked reserves for SAGD, results in a best estimate of total recoverable resource for the lease in the order of 2 billion barrels (300 million barrels net to Enerplus). The best estimate of surface mineable gross bitumen recoverable resources of 1.7 billion barrels recognizes the North Mine as well as other mining areas. We continue to move forward with the first commercial SAGD phase of the project and additional work is underway to further define the opportunities for both SAGD and mining development on this lease. Reserves will be booked to the various potential projects as we advance these projects and resolve outstanding uncertainties on specific project design and timing issues.

In February, we opened our new office in Denver, Colorado which is responsible for the day-to-day operation of our Sleeping Giant project in Montana. The office is also managing the development of our land base in the Williston Basin and assisting our Calgary office in the pursuit of future growth and acquisition opportunities in the United States.

On March 20, we issued 4.37 million trust units through an equity issue that raised gross proceeds of $253.5 million at $58.00 per unit. The issue was very well received by the Canadian marketplace and was sold on a "bought deal" basis. The net proceeds of the offering were initially used to repay outstanding indebtedness and will help fund our capital expenditures program.

The Canadian oil and gas industry continues to face many challenges, not the least of which is the shortage of skilled workers. Rising oil and natural gas prices have spurred the competition for qualified, experienced professionals and have added to the complexity of our business. In a proactive effort to address this future manpower issue, Enerplus has partnered with the Southern Alberta Institute of Technology ("SAIT Polytechnic") to create the Enerplus Innovation Centre, a new centre in the Trades and Technology Complex that will specialize in applied research and innovation. In addition to increasing the number of student seats by 2,735 and apprenticeship seats by 6,000, 60% of the applied research activities will focus on oil and gas development.

We are well underway for another successful year in 2006 with strong production volumes, robust commodity prices, a healthy balance sheet and the most extensive development prospect inventory in our 20 year history.

Gordon J. Kerr
President & Chief Executive Officer

OPERATIONS OVERVIEW

Year-to-date, our 2006 production and development programs are meeting our expectations. First quarter production averaged 85,392 BOE/day, slightly higher than our 2005 fourth quarter production volumes. Production additions from our first quarter development capital program along with carry-forward production from the fourth quarter offset natural declines in our asset base. We continue to target average annual production of 84,000 BOE/day with an exit rate of 89,000 BOE/day.

We achieved record first quarter levels of development capital activity with expenditures of $128.7 million and the drilling of 124.3 net wells with a 100% success rate. Most of our drilling activity was focused on shallow gas and CBM development, while significant investments were also made in our Montana Bakken oil property and our Canadian conventional oil and gas properties. We also spent $8.2 million on land and seismic which is expected to generate additional opportunities in the years ahead. As a result of our organization and pre-planning efforts, we are well positioned to execute on our planned capital investment opportunities throughout the remainder of the year.

Operating costs were in line with expectations at $7.57/BOE for the quarter, up from the first quarter 2005 due to inflationary pressures. We expect to see operating costs per BOE increase during the second quarter as a result of planned plant maintenance activities that will interrupt production. The industry continues to experience cost escalations due to high levels of activity. To help mitigate these increases, we are focusing additional effort on leveraging our size to procure goods and service contracts that can provide greater cost efficiencies. Our full year projection for operating costs remains at $7.95/BOE.

Enerplus enjoys a healthy inventory of oil and gas development prospects in excess of our 2006 target investment level of $485 million. Although all scheduled programs are economically attractive at current commodity prices, we are reviewing our 2006 program in the context of recent escalating oil prices and softening gas prices. We currently have approximately $90 million targeted for long-term opportunities and we may redirect a portion of this capital towards crude oil projects to maximize our return given the current strength of crude oil prices. This could lead to the acceleration of some oil projects in 2006 and the deferral of some gas projects to 2007.

Q1 2006 Development Activity by Play Type	Q1 Capital Spending	Wells Drilled	
		Gross	Net
	($ millions)		
Shallow Natural Gas	$ 12.1	116	59.6
Crude Oil Waterfloods	14.1	14	11.2
Bakken Oil	27.0	8	5.6
Oil Sands	11.1	11	1.7
Coalbed Methane	16.8	41	25.6
Other Conventional Oil & Gas	47.6	99	20.6
Total	**$ 128.7**	**289**	**124.3**

HEALTH & SAFETY

During the first quarter of 2006 Enerplus received a 95% rating upon the completion of our external renewal audit related to the Alberta COR (Certificate of Recognition). The COR is an initiative of Alberta Workplace Health and Safety that provides a framework to promote and certify health and safety programs of companies operating in Alberta. We did experience a number of injury incidents during the quarter relating to our Canadian employees and contractors. While the nature of the majority of incidents is classified in the lower end of severity, we take this very seriously and endeavour to be proactive in the prevention of all incidents. We have responded by increasing our focus and communications throughout the company regarding the prevention of these types of incidents as we strive to improve our health and safety performance on a go-forward basis.

SHALLOW GAS DEVELOPMENT

We continue to pursue an active development program on our shallow natural gas properties in southern Alberta and Saskatchewan, targeting the Milk River, Medicine Hat and Second White Specs formations. During the first quarter we invested $12.1 million and participated in the drilling of 116 gross shallow gas wells (59.6 net). At Verger we participated in 24 gross wells (8.8 net), with production expected to come on stream in May. At Bantry we initiated a high density well program (16 wells/section) with the drilling of 17 gross wells (15.6 net). We expect that production from this program will be on stream in August. We also drilled 17 wells (100% WI) at Medicine Hat North and participated in drilling 18 wells (8.8 net) at Shackleton. Significant additional drilling activity is planned at Shackleton, Hanna and Medicine Hat during the year.

WATERFLOOD DEVELOPMENT

In the first quarter, we invested approximately $14.1 million on waterflood drilling, re-completions, stimulations and optimization activities. We drilled 14 gross wells (11.2 net) including 11 wells (100% WI) at Joarcam in the Viking formation. The Joarcam wells are part of a larger 22 oil well program expected to add 500 BOE/day in 2006. During the course of the year, we plan to drill 7 wells (100% WI) at Pembina and execute on other significant development activities at Medicine Hat and Virden.

BAKKEN OIL DEVELOPMENT

We became a significant Bakken crude oil player in 2005 with the acquisition of interests in the Sleeping Giant project in northeast Montana. In February, we opened our Denver office and are currently building a team of technical professionals to support our strategic growth plans for the United States. First quarter production and development activities occurred as planned with capital investment of $27 million to drill 8 horizontal oil wells (5.6 net) resulting in average production volumes of over 10,000 BOE/day. We ship our crude oil production from this area via a combination of pipeline and trucking. Currently, both pipeline and trucking systems are effectively fully utilized and we could experience temporary curtailments of approximately 250 – 500 bbls/day at any given time. We are working closely with the shippers and industry partners to ensure that the effects of these restrictions are mitigated. Also the pipeline company has plans to expand capacity out of the area to handle the additional production volumes anticipated with the on-going development spending in the area.

OIL SANDS DEVELOPMENT

Our oil sands project continues to be a significant part of our planning activity and future growth opportunity as we progress on both the SAGD and mine development. Enerplus and the operator, Deer Creek Energy Ltd., a wholly-owned subsidiary of Total E&P Canada ("Total"), are currently reviewing options on the optimal lease development plan given the flexibility which exists for both SAGD and mining recovery of the bitumen resource. Given the overburden depth relative to bitumen resource on the western portion of the lease, the option to expand the current mining area exists and could impact the area originally identified for SAGD recovery.

Phase II (SAGD)

Phase II is the first phase of commercial SAGD development on the lease. In the first quarter we completed the initial SAGD drilling and began steam injection as expected. We currently have 17 new well pairs in Phase II plus the initial pilot well pair which will be included in the first commercial project. We expect production from the new wells to begin in May of this year with peak production to occur in the fourth quarter of 2007.

The SAGD development project is slightly behind schedule but is expected to come in essentially on budget at just over $200 million gross ($30 million net to Enerplus). The Joslyn sales pipeline, however, was over budget due to weather, right of way and operational issues. As a result of the project delays, the 2006 exit rate production is projected to be approximately 5,000 bbls/day (gross) and reach peak production expectations in the order of 10,000 bbls/day (1,500 bbls/day net to Enerplus) in the fourth quarter of 2007. We do not expect to report any production until such time as commercial operations have been established and as such, have not included any of these volumes in our overall 2006 corporate guidance.

Phase IIIA/IIIB (SAGD)

Phase IIIA is a 26 well pair SAGD project expected to start up in 2008 and reach an estimated 15,000 bbls/day gross peak production rate in 2010. Phase IIIB is an additional 15,000 bbls/day gross peak production rate project which may startup in 2010. The operator has completed the preliminary engineering design for Phase IIIA and we anticipate receiving regulatory approval early in the third quarter. Currently Phase IIIA is booked as probable reserves and no reserves are carried for the Phase IIIB project.

We are currently reviewing options for lease development including the potential to mine areas of the lease which could impact the scope of Phase IIIA and IIIB. Given that we currently have a portion of the Phase IIIA SAGD reserves booked as probables and no reserves associated with Phase IIIB, a decision to mine some currently identified SAGD areas could result in changes to reserves and projected production on this portion of the lease. Mining typically provides about twice the recovery of the original bitumen in place versus SAGD projects.

Mining Resource Potential

The Joslyn lease has the potential for resource recovery from both the SAGD process as well as mining. An independent third party analysis commissioned by Enerplus considered the mining opportunities contained within the lease and prepared a low, best and high estimate of gross lease recoverable, surface mineable, bitumen resources of approximately 1.1, 1.7 and 2.3 billion barrels, respectively. Enerplus has a 15 percent working interest in the lease.

The resource estimates recognize select mine areas beyond the North Mine, however, they do not consider potential mining opportunities within the SAGD potential area. The range reflects the current uncertainty associated with the geological model, pit development and design issues, and extraction recovery. The low resource estimate considers a total volume of material to bitumen in place (TV:BIP) limit of approximately 12:1, consistent with the North Mine application, while the high resource estimate considers a TV:BIP limit of approximately 15:1, subject to site layout constraints relating to the North Mine development plan. As the TV:BIP pit limit increases, the mine operation accesses deeper bitumen with increased overburden. If the mining areas were expanded to impact the SAGD area, this would likely result in incremental total resources and ultimately reserves for the lease.

Additional work including detailed economic comparisons of expanded mining operations versus SAGD, confirmation of project timing, pilot testing on new technologies included in the North Mine application, development of the marketing plans for the lease, and additional core hole drilling will further define the opportunities for both SAGD and mining development on this lease. Given the uncertainties around the specific project scope, timing, use of new technologies, and the marketing plans for the lease, none of the resources associated with the mining area were classified as reserves at this time. As these uncertainties are further resolved, we would expect to begin booking probable reserves for the mining area.

North Mine

The North Mine represents a 100,000 bbl/day (gross) project and 890 million barrels of recoverable resource per the application submitted by the operator (134 million barrels net to Enerplus). The North Mine application was filed in February and is currently being reviewed by the government regulators. The operator currently anticipates project approval late in 2007 with project startup in 2010/2011 and full production by 2014. Current industry pressures from a significant number of competing projects could impact project timing.

The interim reserves/resources report includes a best estimate of resources for the North Mine of 950 million barrels (142 million net) which is comparable to the recoverable resource estimated in the mining application discussed above. The report also includes a low and high estimate for the North Mine of 790 and 1,170 million barrels (gross), respectively.

COALBED METHANE DEVELOPMENT

Coalbed methane ("CBM") continues to represent a significant piece of Enerplus' capital development portfolio. During the first quarter of 2006, we invested approximately $16.8 million on development activities, including participation in 41 gross wells (25.6 net) targeting the Horseshoe Canyon formation in central Alberta. The Horseshoe Canyon coals are typically dry and do not have the water handling issues often associated with CBM production found in other areas in North America. At Bashaw, we drilled 7 gross wells (5.6 net). We also participated in 12 gross wells (6 net) at Joffre and drilled 8 gross wells (6.8 net) at Trochu. We expect that all of these new wells at Bashaw, Joffre and Trochu will be tied in by the end of the second quarter. We are currently reviewing our 2006 CBM drilling plans at Bashaw due to area transportation issues. This review could result in a reallocation of a portion of our 2006 CBM capital program to other play types with the balance of CBM drilling deferred to 2007.

OTHER CONVENTIONAL DEVELOPMENT

During the first quarter of 2006, we invested $47.6 million in other conventional development properties, drilling 99 gross wells (20.6 net) throughout western Canada. We invested $9 million of this total participating in the drilling of 21 gross wells (1.2 net) in the deep gas formations of the Foothills and Deep Basin areas of western Alberta and northeast British Columbia. We expect to continue to participate in joint venture deep gas drilling opportunities during the remainder of the year.

At Bantry North, a non-operated sour gas facility was completed allowing for additional production capability of 1,400 BOE/day from our 2005 development activities to come on stream. We have experienced some production interruptions as the plant undergoes expansion and we expect that our full production capability will be achieved during the course of the year. Additional 2006 development plans include drilling 5 (100% WI) oil wells in the Sunburst formation in the third quarter.

ACQUISITIONS AND DIVESTMENTS

Although no significant acquisitions were completed in the first quarter, we did execute on a number of focused acquisitions, increasing working interests in existing strategic portfolio areas. This included the addition of interests to our Gleneath light oil unit and the Sleeping Giant project in Montana. In total, we acquired approximately 2.9 million BOE of proved plus probable reserves and 442 BOE/day of production for $30 million resulting in attractive acquisition metrics of $10.23 per BOE of proved plus probable reserves excluding future development capital and $67,990/BOE of current daily production.

We also divested 3.3 million BOE of proved plus probable reserves, with no associated production for $19.7 million. The bulk of our disposition activity was the strategic sale of a 1% working interest in our Joslyn oil sands project in return for an equity ownership position in Laricina Energy Ltd. Laricina is a private oil sands focused company run by the former CEO of Deer Creek Energy Limited. In addition to the equity interest, we are participating with Laricina in an area of mutual interest to jointly pursue additional in-situ oil sands ventures.

We continue to actively evaluate conventional opportunities in the Canadian and U.S. markets focusing on acquisitions which provide attractive base economics and long-term upside through repeatable low risk development. Given a very competitive acquisition market and our extensive portfolio of internal development opportunities we remain focused in our acquisition efforts looking for transactions which complement our execution capabilities and that meet our risk/return requirements. In addition to our conventional activities, we continue to evaluate transactions to expand our non-conventional opportunity set including: additional oil sands opportunities, our equity investment strategy and expansion into new international areas.

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

The following discussion and analysis of financial results is dated May 4, 2006 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, 2005 and 2004; and
- the unaudited interim consolidated financial statements as at and for the three months ended March 31, 2006 and 2005.

All amounts are stated in Canadian dollars unless otherwise specified. 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. 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.

NON-GAAP MEASURES

Throughout the MD&A, we use the terms funds flow from operations ("funds flow") and cash available for distribution. These terms as presented do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles ("GAAP"), and therefore they may not be comparable with the calculation of similar measures for other entities. Funds flow as presented is not intended to represent operating cash flows or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. Funds flow is used by management to analyze operating performance, leverage and liquidity. All references to funds flow throughout this report are based on cash flow from operating activities before changes in non-cash working capital. Refer to the Cash Available for Distribution section of the MD&A for a quantitative reconciliation of funds flow to cash flow from operating activities.

Cash available for distribution is calculated using funds flow less discretionary amounts of cash withheld for acquisitions, capital expenditures and debt repayment. In the past, we have used the term "distributable income" and "cash available for distribution" interchangeably in our public disclosure documents. In the future, we intend to only use the term "cash available for distribution" in all such documents.

OVERVIEW

Increased production from prior year acquisitions and our ongoing development capital program combined with continued high commodity prices delivered strong funds flow in the first quarter. Development capital spending totaled $128.7 million, resulting in the addition of 124 net wells with a 100% success rate. Overall operating metrics were in-line with our guidance. We continue to expect annual production for 2006 to average approximately 84,000 BOE/day with an average exit rate of 89,000 BOE/day. We closed an equity offering at $58.00 per unit on March 20, 2006 that resulted in gross proceeds of $253.5 million ($240.3 million net of issuance costs). The net proceeds were used to repay bank indebtedness and will subsequently be used to fund development capital and other general corporate expenditures.

RESULTS OF OPERATIONS

Production

We achieved average production of 85,392 BOE/day for the first quarter of 2006, an 8% increase over our average production volumes of 78,813 BOE/day for the first quarter of 2005. This increase is a result of our acquisitions completed during the second half of 2005 as well as our ongoing development capital program.

Our average production during the three months ended March 31, 2006 was weighted 53% natural gas and 47% crude oil and natural gas liquids on a BOE basis, compared to the first quarter of 2005 when our production was weighted 59% natural gas and 41% liquids on a BOE basis. Our U.S. acquisitions of light sweet crude oil contributed to this change in production mix. Average production volumes for the three months ended March 31, 2006 and 2005 are outlined below:

	Three months ended March 31,		
Daily Production Volumes	2006	2005	% Change
Natural gas (Mcf/day)	270,765	280,463	(3%)
Crude oil (bbls/day)	35,853	27,448	31%
Natural gas liquids (bbls/day)	4,411	4,621	(5%)
Total daily sales (BOE/day)	85,392	78,813	8%

We are maintaining our annual production estimate of 84,000 BOE/day, however during the second quarter we expect a temporary decrease in production as a result of scheduled plant maintenance.

Pricing

Our earnings, funds flow and financial condition are dependent on the prices received for our natural gas and crude oil production. The following tables compare our average selling prices and benchmark price indices for the three months ended March 31, 2006 and 2005.

	Three months ended March 31,		
Average Selling Price[1]	2006	2005	% Change
Natural gas (per Mcf)	$ 8.33	$ 6.58	27%
Crude oil (per bbl)	55.20	47.61	16%
Natural gas liquids (per bbl)	50.57	43.80	15%
Per BOE	$52.27	$42.55	23%

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

Average Benchmark Pricing	Three months ended March 31, 2006	2005	% Change
AECO natural gas – monthly index (CDN$/Mcf)	$ 9.27	$ 6.69	39%
AECO natural gas – daily index (CDN$/Mcf)	7.56	6.87	10%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	9.07	6.32	44%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	10.43	7.71	35%
WTI crude oil (US$/bbl)	63.48	49.84	27%
WTI crude oil: CDN$ equivalent (CDN$/bbl)	72.99	60.78	20%
CDN$/US$ exchange rate	$ 0.87	$ 0.82	6%

We realized an average price on our natural gas of $8.33/Mcf (net of transportation) during the three months ended March 31, 2006 an increase of 27% from $6.58/Mcf for the same period in 2005. In general, natural gas prices in February and March 2006 retracted approximately 35% from January levels in response to the unusually warm winter and the lower than normal storage withdrawal. In comparison to the first quarter of 2005, the AECO monthly index price for natural gas increased 39% and the AECO daily index price increased 10%. We sell our natural gas under both month and day AECO index contracts. As a result, our realized natural gas price during the first quarter increased 27%, comparable to the 24% blended increase of the combined indices.

The average price we received for our crude oil during the three months ended March 31, 2006 increased 16% to $55.20/bbl (net of transportation) from $47.61/bbl during the same period of 2005. In comparison, the West Texas Intermediate ("WTI") crude oil benchmark price, after adjusting for the change in the US$ exchange rate, increased 20% for the corresponding period in 2005. Our average crude oil price did not increase to the extent of the underlying WTI despite the fact that we added additional light sweet production in 2006. Across North America the differential between physically delivered crude oil and the WTI contract traded in New York at the Mercantile Exchange (NYMEX) has widened impacting realized prices within our industry. The differentials widened due to a number of factors including North American supply and demand, inventory levels, reduced refinery utilization and quality differences.

The Canadian dollar strengthened 6% against the U.S. dollar during the first quarter of 2006 compared to the same period in 2005. 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 reduced the Canadian dollar prices that we would have otherwise realized.

Price Risk Management

We continue to review our risk management strategies in response to the volatile price environment and the economics of our acquisitions and development projects together with our overall financial position. We have not entered into any financial contracts since the third quarter of 2005 and as a result the number of outstanding derivative financial instruments continues to decrease as existing contracts expire. All current outstanding financial contracts will expire during 2006.

Our commodity price risk management program incurred cash costs of $12.9 million on crude oil contracts and cash costs of $10.0 million on natural gas contracts during the first quarter of 2006, compared to cash costs of $18.8 million and $1.4 million respectively during the first quarter of 2005. Fewer outstanding crude oil contracts, partially offset by increased crude oil prices, caused the decrease in cash costs on crude oil contracts. Although there were fewer natural gas contracts outstanding, significantly higher natural gas prices in January of 2006 caused the increase in cash costs on natural gas contracts.

The unrealized gain on our financial contracts of $40.3 million for the three months ended March 31, 2006 represents the change in the fair value of financial contracts since December 31, 2005 and results in a non-cash increase to earnings. At March 31, 2006 the fair value of our financial contracts of $17.1 million is recorded on the balance sheet as a deferred credit. See Note 2 for details.

Effective December 31, 2005, we elected to stop designating our commodity financial contracts as hedges. As a result we recorded a deferred credit representing the fair value of these contracts on that day, with an offset recorded as a deferred financial asset that is amortized to income over the life of the underlying contracts. For the period ended March 31, 2006 we recorded $18.3 million of amortization related to these contracts. The remaining deferred financial asset of $31.6 million at March 31, 2006 will be amortized during the remainder of the year as the underlying contracts mature. See Note 2 for details.

Risk Management Costs ($ millions, except per unit amounts)	Three months ended March 31, 2006		Three months ended March 31, 2005	
Cash costs:				
Crude oil	$ 12.9	$ 4.00/bbl	$18.8	$ 7.61/bbl
Natural Gas	10.0	$ 0.41/Mcf	1.4	$0.06/Mcf
Total Cash costs	$ 22.9	$ 2.98/BOE	$20.2	$2.86/BOE
Non-cash costs:				
Change in fair value – financial contracts	$(40.3)	$(5.24)/BOE	$31.3	$4.41/BOE
Amortization of deferred financial assets	18.3	2.38/BOE	1.0	0.14/BOE
Total Non-cash costs	$(22.0)	$(2.86)/BOE	$32.3	$4.55/BOE
Total costs	$ 0.9	$ 0.12/BOE	$52.5	$7.41/BOE

REVENUES

Crude oil and natural gas revenues for the three months ended March 31, 2006 were $401.7 million ($407.8 million, net of $6.1 million of transportation costs) compared to $301.8 million ($309.0 million, net of $7.2 million of transportation costs) for the same period in 2005. The increase of $99.9 million, or 33%, is primarily due to higher commodity prices as well as increased crude oil production resulting from our 2005 acquisitions.

Analysis of Sales Revenue(1) ($ millions)	Crude oil	NGLs	Natural Gas	Total
Quarter ended March 31, 2005	$117.6	$18.2	$166.0	$301.8
Price variance(1)	24.5	2.7	43.1	70.3
Volume variance	36.0	(0.8)	(5.6)	29.6
2006 Sales Revenue	$178.1	$20.1	$203.5	$401.7

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

ROYALTIES

Royalties are paid to various government entities and other land and mineral rights owners. For the three months ended March 31, 2006 royalties increased to $80.0 million compared to $62.3 million during 2005, both approximately 20% of oil and gas sales, net of transportation. The increase is consistent with our revenue analysis of higher production and commodity prices during the first quarter. We continue to expect royalties to be between 19% and 20% for the remainder of the year.

OPERATING EXPENSES

Operating expenses for the three months ended March 31, 2006 were $58.2 million or $7.57/BOE compared to $49.5 million or $6.98/BOE for the same period in 2005. Total operating costs have increased over the prior period due to cost pressures related to the high level of industry activity and more specifically those costs associated with repairs and maintenance, well servicing and utilities. These increases were in line with our expectations for the first quarter.

Scheduled plant maintenance that will temporarily impact production is expected to increase operating costs both in total and per BOE during the second quarter. We are maintaining our operating cost guidance of approximately $7.95/BOE for the year ended 2006.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative ("G&A") expenses were $13.3 million or $1.73/BOE for the three months ended March 31, 2006 compared to $8.3 million or $1.18/BOE for the first quarter of 2005. Cash G&A expenses of $1.58/BOE in the first quarter of 2006 were slightly higher than our guidance of $1.55/BOE and significantly higher compared to $1.09/BOE in the first quarter of 2005. The cost pressures to retain, recruit and expand a highly skilled professional and technical team have resulted in increased compensation and benefits being paid during 2006 compared to previous years.

On October 1, 2005 we retroactively adopted the fair value method of accounting for our trust unit rights incentive plan to January 1, 2003. For comparative purposes the 2005 quarters have been restated to reflect the adoption of the fair value method of accounting for the trust unit rights incentive plan. See Notes 1 and 4 for further details. For the three months ended March 31, 2006 these non-cash charges were $1.2 million or $0.15/BOE compared to $0.6 million or $0.09/BOE for the first quarter of 2005.

We are maintaining our annual guidance of $1.70/BOE for G&A.

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

General and Administrative Costs	Three months ended March 31,	
($ millions)	2006	2005
Cash	$12.1	$ 7.7
Non-cash trust unit rights incentive plan[1]	1.2	0.6
Total G&A	$13.3	$ 8.3

(Per BOE)	2006	2005
Cash	$1.58	$1.09
Non-cash trust unit rights incentive plan[1]	0.15	0.09
Total G&A	$1.73	$1.18

(1) See trust unit rights incentive plan discussion in Note 1

INTEREST EXPENSE

Interest expense increased to $8.2 million for the first quarter of 2006 from $5.9 million during the same period of 2005. The increase is due to higher average indebtedness and higher interest rates during the first quarter of 2006. At March 31, 2006, approximately 26% of our debt was based on fixed interest rates while 74% was floating.

CAPITAL EXPENDITURES

During the three months ended March 31, 2006 we spent $128.7 million on development drilling and facilities compared to $69.3 million during the same period in 2005. We achieved a 100% success rate in drilling 124 net wells during the quarter focusing primarily on shallow gas and CBM development. We also made significant development investments in our U.S. Bakken oil property and Canadian conventional oil and gas properties.

Property acquisitions for the quarter included additional interests in the Gleneath area for $11.8 million and the Sleeping Giant project in Montana for $14.6 million. We also sold a 1% interest in the Joslyn project for $19.7 million in exchange for an equity interest of approximately 19% in Laricina Energy Ltd. ("Laricina") valued at $19.5 million and cash of $0.2 million. This reduced our interest in the Joslyn project to 15%.

Our capital expenditures were financed by withholding a portion of our cash available for distribution, additional debt and an equity issuance completed during the first quarter. Total net capital expenditures of $139.8 million for the first quarter of 2006 compared to $9.9 million for the first quarter of 2005 are outlined below.

Capital Expenditures ($ millions)	Three months ended March 31, 2006	2005
Development expenditures	$ 97.7	$ 54.3
Plant and facilities	31.0	15.0
Development Capital	128.7	69.3
Office	0.8	0.5
Sub-total	129.5	69.8
Acquisitions of oil and gas properties	30.0	1.8
Dispositions of oil and gas properties	(19.7)	(61.7)
Total Net Capital Expenditures	$139.8	$ 9.9
Total Capital Expenditures financed with funds flow	$ 61.1	$ 9.9
Total Capital Expenditures financed with debt and equity	98.2	–
Total non-cash consideration for 1% sale of Joslyn project	(19.5)	–
Total Net Capital Expenditures	$139.8	$ 9.9

We are maintaining our 2006 annual guidance of $485 million for development capital spending.

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, 2006, DDA&A increased to $111.6 million or $14.52/BOE compared to $87.0 million or $12.26/BOE during the corresponding period in 2005. The increase in DDA&A per BOE is due to increased plant, property and equipment from acquisitions completed during the second half of 2005.

No impairment of the Fund's assets existed at March 31, 2006 using year-end reserves updated for acquisitions, divestitures and management's estimates of future prices.

TAXES

Future Income Taxes

Future income taxes arise from differences between the accounting and tax bases of the operating companies' assets and liabilities. The future income tax liability that is recorded on the balance sheet is recovered through earnings over time.

For the three months ended March 31, 2006, a future income tax recovery of $1.7 million was recorded in income compared to a future income tax recovery of $29.6 million during the same period in 2005. This change is due to the combination of a future tax expense with respect to our U.S. operations and a change in estimate of royalty payments between the operating subsidiaries and the Fund.

Current Income Taxes

In our current structure, payments are made between the Canadian operating entities and the Fund, ultimately transferring both income and future income tax liability to our unitholders. Therefore, no cash income taxes have been paid by our Canadian operating entities.

For the three months ended March 31, 2006, our U.S. operations incurred taxes (income and withholding) in the amount of $3.9 million. We did not have U.S. operations during the first quarter of 2005 therefore no amount was recorded. 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 funds flow were lower in the first quarter, we continue to expect current and income withholding taxes will be approximately 20% of funds flow from U.S. operations on an annual basis.

SELECTED FINANCIAL RESULTS

	Three months ended March 31,	
Per BOE of production (6:1)	2006	2005
Production per day	85,392	78,813
Weighted average sales price[1]	$ 52.27	$ 42.55
Royalties	(10.40)	(8.78)
Financial contracts	(0.12)	(7.41)
Add back / (deduct): Non-cash financial contracts	(2.86)	4.55
Operating costs	(7.57)	(6.98)
General and administrative[2]	(1.73)	(1.18)
Add back: Non-cash G&A expense (trust unit rights)[2]	0.15	0.09
Interest expense, net of interest and other income	(0.89)	(0.72)
Foreign exchange (loss) gain	(0.02)	(0.04)
Deduct: Non-cash foreign exchange loss	0.01	0.05
Capital taxes	(0.18)	(0.17)
Current income tax	(0.50)	–
Restoration and abandonment cash costs	(0.40)	(0.29)
Funds flow from operations	27.76	21.67
Restoration and abandonment cash costs	0.40	0.29
Non-cash items:		
Depletion, depreciation, amortization and accretion	(14.52)	(12.26)
Financial contracts	2.86	(4.55)
G&A expense (trust unit rights)[2]	(0.15)	(0.09)
Foreign exchange	(0.01)	(0.05)
Future income tax recovery	0.22	4.18
Total net income per BOE	$ 16.56	$ 9.19

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments
(2) See trust unit rights incentive plan discussion in Note 1

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

The following table provides a geographical analysis of key financial results for the three months ended March 31, 2006. Prior period information has not been presented as we commenced operations in the U.S. on August 30, 2005.

	Three months ended March 31, 2006		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total
Daily Production Volumes			
Natural gas (Mcf/day)	265,354	5,411	270,765
Crude oil (bbls/day)	26,339	9,514	35,853
Natural gas liquids (bbls/day)	4,411	–	4,411
Total Daily Sales (BOE/day)	74,976	10,416	85,392
Pricing[1]			
Natural gas (per Mcf)	$ 8.32	$ 8.61	$ 8.33
Crude oil (per bbl)	$51.69	$64.93	$55.20
Natural gas liquids (per bbl)	$50.57	$ –	$50.57
Capital Expenditures			
Development capital and office	$102.0	$ 27.5	$129.5
Acquisitions of oil and gas properties	$ 15.4	$ 14.6	$ 30.0
Dispositions of oil and gas properties	$ (19.7)	$ –	$ (19.7)
Revenues			
Oil and gas sales[1]	$348.0	$ 59.8	$407.8
Royalties[2]	$ (68.6)	$ (11.4)	$ (80.0)
Financial contracts	$ (0.9)	$ –	$ (0.9)
Expenses			
Operating	$ 56.5	$ 1.7	$ 58.2
General and administrative	$ 12.5	$ 0.8	$ 13.3
Depletion, depreciation, amortization and accretion	$ 85.7	$ 25.9	$111.6
Current income taxes	$ –	$ 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

FUNDS FLOW FROM OPERATIONS AND NET INCOME

Funds flow from operations for the three months ended March 31, 2006 was $213.3 million or $1.80 per trust unit compared to $153.7 million or $1.47 per trust unit for the three months ended March 31, 2005. The increase in funds flow from operations was primarily a result of higher production and commodity prices, offset by higher operating and G&A costs during the first quarter of 2006 compared to 2005.

Net income for the first quarter of 2006 was $127.3 million or $1.08 per trust unit compared to $65.2 million or $0.63 per trust unit for the first quarter of 2005. The increase in net income was largely due to more favourable commodity prices, higher production and a non-cash gain (versus a non-cash cost in 2005) on the fair market value of our financial contracts. This was partially offset by increased royalties, depletion and operating costs as well as a lower future income tax recovery.

QUARTERLY FINANCIAL INFORMATION

Generally, oil and gas revenues have increased due to higher commodity prices and production, offset by an increased Canadian/U.S. dollar exchange rate. Production increases can be attributed to our acquisitions and development capital program during the last two years. Oil and gas revenues decreased from the fourth quarter of 2005 to the first quarter of 2006 largely due to lower natural gas prices. Net income has been affected by fluctuations in oil and gas sales, changes in cash and non-cash risk management costs, the strengthening Canadian dollar and inflationary increases associated with the high level of industry activity.

Quarterly Financial Information ($ millions, except per trust unit amounts)	Oil and Gas Revenue(1)	Net Income	Net income per trust unit	
			Basic	Diluted
2006				
First quarter	$ 401.7	$127.3	$1.08	$1.07
2005(2)				
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
2004				
Fourth quarter	$ 317.5	$114.5	$1.10	$1.10
Third quarter	302.2	50.6	0.49	0.49
Second quarter	265.6	48.0	0.51	0.51
First quarter	239.3	45.2	0.48	0.48
Total	$1,124.6	$258.3	$2.60	$2.60

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments
(2) See trust unit rights incentive plan discussion in Note 1

CASH AVAILABLE FOR DISTRIBUTION

Our payout ratio for the three months ended March 31, 2006 was 71%, the same as the corresponding period in 2005. During the first quarter of 2006, we funded $159.5 million in acquisitions and capital spending by withholding a portion of our cash available for distribution, additional debt and an equity issuance.

We continually monitor our distribution payout ratio with respect to forecasted funds flows, debt levels and spending plans. The level of cash withheld typically varies between 10% and 40% of annual funds flow. We are prepared to adjust the payout levels in an effort to balance the investor's desire for distributions with the Fund's requirement to maintain a prudent capital structure. The actual amount of cash withheld is dependant upon our current levels of production, the prevailing commodity price environment and the Board of Directors' discretion.

The following table reconciles Enerplus' funds flow from operations with the cash available for distribution to unitholders.

Reconciliation of Cash Available for Distribution ($ millions, except per unit amounts)	Three months ended March 31, 2006	2005
Cash flow from operating activities	$189.3	$130.3
Change in non-cash working capital	24.0	23.4
Funds flow from operations	213.3	153.7
Cash withheld for acquisitions, capital expenditures and debt repayment[1]	(61.1)	(43.9)
Cash available for distribution[2]	$152.2	$109.8
Cash available for distribution per trust unit	$ 1.26	$ 1.05
Payout ratio	71%	71%

(1) Cash withheld for acquisitions, capital expenditures and debt repayment is a discretionary amount and represents the difference between cash flow from operations less distributions

(2) Cash available for distribution will differ from Cash Distributions to Unitholders on the Consolidated Statements of Cash Flows due to the timing of distribution announcements and the number of trust units outstanding on the record dates

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2006 our balance sheet remains strong with conservative debt levels of 0.6 times debt to trailing funds flow. This is a result of the current high commodity price environment, increased production, and our net proceeds of $240.3 million from our March 2006 equity issue, offset by our first quarter capital spending.

During the first quarter long-term debt, net of cash, decreased $123.9 million to $525.9 million, which is comprised of $194.5 million of bank indebtedness and $331.4 million of senior unsecured notes.

The following table provides certain key financial ratios for the Fund:

Financial Leverage and Coverage	March 31, 2006	December 31, 2005
Long-term debt to trailing funds flow	0.6x	0.8x
Funds flow to interest expense	30.5x	30.8x
Long-term debt to long-term debt plus equity	16%	21%

Long-term debt is measured net of cash
Funds flow and interest expense are 12-months trailing (calculated based on the last 12 months after adjusting for acquisitions)

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 funds flow be insufficient to repay this indebtedness.

We anticipate that we will continue to have adequate liquidity to fund future working capital and planned capital expenditures during 2006 primarily through funds flow from operations and the proceeds of the March 2006 equity issue. Enerplus' capital budget for 2006 can be revised downward in the event of a significant commodity price downturn or a similar economic event.

TRUST UNIT INFORMATION

We had 122,232,000 trust units outstanding at March 31, 2006 compared to 104,586,000 trust units at March 31, 2005 and 117,539,000 at December 31, 2005. The weighted average basic number of trust units outstanding during the first quarter of 2006 was 118,221,000 (2005 – 104,269,000).

During the three months ended March 31, 2006, 323,000 trust units (2005 – 462,000) were issued pursuant to the Trust Unit Monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP") and the trust unit rights incentive plan. This resulted in $13.4 million (2005 – $14.6 million) of additional equity to the Fund. For further details see Note 4.

On March 20, 2006 we closed an equity offering for a total of 4,370,000 units at a price of $58.00 per unit for gross proceeds of $253.5 million ($240.3 million net of issuance costs). The proceeds of the offering were initially used to repay indebtedness under our credit facilities and will subsequently be used to fund development capital as well as other general corporate expenditures.

CANADIAN AND U.S. TAXPAYERS

Enerplus estimates that approximately 95% of cash distributions paid to Canadian and U.S. unitholders will be taxable and the remaining 5% 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 funds 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.

In May 2006, Enerplus estimated its non-resident ownership to be approximately 71%.

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 discussion and analysis contains certain forward-looking statements and forward-looking information which are based on Enerplus' current internal expectations, estimates, projections, assumptions and beliefs. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "plan", "should", "believe" and similar expressions are intended to identify forward-looking statements and forward-looking information. These statements are not guarantees of future performance and 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 statements or information. Enerplus believes the expectations reflected in those forward-looking statements and information are reasonable but no assurance can be given that these expectations will prove to be correct, and such forward-looking statements and information included in this discussion and analysis should not be unduly relied upon. Such forward-looking statements and information speak only as of the date of this discussion and analysis and Enerplus does not undertake any obligation to publicly update or revise any forward-looking statements or information, except as required by applicable laws.

CONSOLIDATED BALANCE SHEETS

(CDN$ thousands) (Unaudited)	March 31, 2006	December 31, 2005
Assets		
Current assets		
Cash	$ 1,265	$ 10,093
Accounts receivable	134,943	170,623
Deferred financial assets (Note 2)	31,578	49,874
Other current	22,454	26,751
	190,240	257,341
Property, plant and equipment (Note 3)	3,689,539	3,650,327
Goodwill	221,847	221,234
Other assets	21,200	1,721
	$ 4,122,826	$ 4,130,623
Liabilities		
Current liabilities		
Accounts payable	$ 241,400	$ 316,875
Distributions payable to unitholders	51,367	49,367
Deferred credits (Note 2)	17,087	57,368
	309,854	423,610
Long-term debt	527,129	659,918
Future income taxes	441,887	442,970
Asset retirement obligations	115,464	110,606
	1,084,480	1,213,494
Equity		
Unitholders' capital (Note 4)	3,665,481	3,410,614
Accumulated income	1,535,470	1,408,178
Accumulated cash distributions	(2,459,950)	(2,309,705)
Cumulative translation adjustment	(12,509)	(15,568)
	2,728,492	2,493,519
	$ 4,122,826	$ 4,130,623

CONSOLIDATED STATEMENTS OF INCOME

(CDN$ thousands except per trust unit amounts) (Unaudited)	Three months ended March 31, 2006	2005
Revenues		
Oil and gas sales	$407,838	$308,960
Royalties	(79,971)	(62,268)
Derivative instruments (Notes 2 and 5)		
Financial contracts – qualified hedges	–	(2,892)
Other financial contracts	(895)	(49,649)
Interest and other income	1,335	808
	328,307	194,959
Expenses		
Operating	58,165	49,477
General and administrative	13,305	8,343
Transportation	6,112	7,159
Interest on long-term debt	8,163	5,921
Foreign exchange loss	154	313
Depletion, depreciation, amortization and accretion	111,551	86,963
	197,450	158,176
Income before taxes	130,857	36,783
Capital taxes	1,435	1,241
Current taxes	3,862	–
Future income tax recovery	(1,732)	(29,636)
Net Income	$127,292	$ 65,178
Net income per trust unit		
Basic	$ 1.08	$ 0.63
Diluted	$ 1.07	$ 0.62
Weighted average number of trust units outstanding (thousands)		
Basic	118,221	104,269
Diluted	118,725	104,777

CONSOLIDATED STATEMENTS OF ACCUMULATED INCOME

(CDN$ thousands) (Unaudited)	Three months ended March 31, 2006	2005
Accumulated income, beginning of period	$1,408,178	$ 976,137
Net income	127,292	65,178
Accumulated income, end of period	$1,535,470	$1,041,315

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended March 31,	
(CDN$ thousands) (Unaudited)	2006	2005
Operating Activities		
Net income	$ 127,292	$ 65,178
Non-cash items add/(deduct):		
Depletion, depreciation, amortization and accretion	111,551	86,963
Financial contracts (Note 2)	(21,985)	32,296
Foreign exchange loss	65	324
Trust unit rights incentive plan (Note 4)	1,187	662
Future income tax recovery	(1,732)	(29,636)
Asset retirement costs incurred	(3,063)	(2,046)
	213,315	153,741
Increase in non-cash working capital	(24,034)	(23,382)
	189,281	130,359
Financing Activities		
Issue of trust units, net of issue costs (Note 4)	253,680	14,587
Cash distributions to unitholders	(150,245)	(109,686)
Decrease in bank credit facilities	(132,854)	(22,946)
Decrease in non-cash financing working capital	2,000	164
	(27,419)	(117,881)
Investing Activities		
Capital expenditures	(129,560)	(69,747)
Property acquisitions	(30,027)	(1,820)
Property dispositions	189	61,689
Increase in non-cash investing working capital	(11,433)	(2,600)
	(170,831)	(12,478)
Effect of exchange rate changes on cash	141	–
Change in cash	(8,828)	–
Cash, beginning of period	10,093	–
Cash, end of period	$ 1,265	$ –
Supplementary Cash Flow Information		
Cash income taxes paid	$ 254	$ –
Cash interest paid	$ 4,523	$ 2,385

CONSOLIDATED STATEMENTS OF ACCUMULATED CASH DISTRIBUTIONS

	Three months ended March 31,	
(CDN$ thousands) (Unaudited)	2006	2005
Accumulated cash distributions, beginning of period	$2,309,705	$1,811,500
Cash distributions	150,245	109,686
Accumulated cash distributions, end of period	$2,459,950	$1,921,186

(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, 2005. 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, 2005. The disclosures provided below are incremental to those included in the 2005 annual consolidated financial statements.

On October 1, 2005 the Fund retroactively adopted the fair value method of accounting for the trust unit rights incentive plan to January 1, 2003. Under this method, the fair value of the rights is calculated on the date in which fair value can reasonably be determined, generally being the grant date. The impact of the adoption on our 2003 and 2004 reported earnings was not material and therefore those prior year financial statements have not been restated. The 2005 impact was recorded upon adoption. For comparison purposes the 2005 quarters have been restated to reflect the fair value methodology. The impact on the first quarter of 2005 was a decrease to general and administrative expenses ("G&A") of $2,986,000 and a decrease to contributed surplus of $5,276,000.

2. DEFERRED FINANCIAL ASSETS AND DEFERRED CREDITS

Current Deferred Financial Assets
($ thousands)

Deferred financial assets as at December 31, 2005	$ 49,874
Amortization of deferred financial assets(1)	(18,296)
Deferred financial assets as at March 31, 2006	**$ 31,578**

(1) Represents the amortization of the fair value of financial contracts on December 31, 2005 for which hedge accounting is no longer applied. These deferred financial assets will be amortized over the remaining lives of the associated financial contracts.

Current Deferred Credits
($ thousands)

Deferred credits as at December 31, 2005	$ 57,368
Change in fair value – other financial contracts(1)	(40,281)
Deferred credits as at March 31, 2006	**$ 17,087**

(1) Changes in the fair value of financial contracts that do not qualify for hedge accounting are taken into income during the period as other financial contracts and reflected as an increase or decrease in the deferred financial liability

The following table summarizes the income statement effects of other financial contracts:

Other Financial Contracts ($ thousands)	Three months ended March 31, 2006	2005
Change in fair value	$(40,281)	$31,290
Amortization of deferred financial assets	18,296	1,006
Realized cash costs, net	22,880	17,353
Other financial contracts	$ 895	$49,649

During the three months ended March 31, 2006 the Fund realized cash costs of $nil, net of gains and losses from financial contracts that qualified as hedges compared to cash costs of $2,892,000 during the same period of 2005.

3. PROPERTY, PLANT AND EQUIPMENT

($ thousands)	March 31, 2006	December 31, 2005
Property, plant and equipment	$ 5,454,952	$ 5,306,137
Accumulated depletion, depreciation and accretion	(1,765,413)	(1,655,810)
Net property, plant and equipment	$ 3,689,539	$ 3,650,327

Capitalized development G&A of $3,208,000 (2005 – $2,508,000) is included in property, plant and equipment ("PP&E") for the three months ended March 31, 2006. Excluded from PP&E for the purpose of the depletion and depreciation calculation is $49,328,000 (2005 – $36,134,000) related to the Joslyn development project that has not yet commenced commercial production.

4. FUND CAPITAL

(a) Unitholders' Capital

Trust Units
Authorized: Unlimited number of trust units

Issued: (thousands)	Three months ended March 31, 2006 Units	Three months ended March 31, 2006 Amount	Year ended December 31, 2005 Units	Year ended December 31, 2005 Amount
Balance before Contributed Surplus, beginning of period	117,539	$3,407,567	104,124	$2,826,641
Issued for cash:				
Pursuant to public offerings	4,370	240,287	10,638	466,885
Pursuant to rights plans	210	7,166	805	24,737
Trust unit rights incentive plan (non-cash) – exercised	–	519	–	4,629
DRIP*, net of redemptions	113	6,227	339	15,613
Issued for acquisition of corporate and property interests (non-cash)	–	–	1,633	69,062
	122,232	3,661,766	117,539	3,407,567
Contributed Surplus (Trust unit rights incentive plan)	–	3,715	–	3,047
Balance, end of period	122,232	$3,665,481	117,539	$3,410,614

* Distribution Reinvestment and Unit Purchase Plan

Contributed surplus ($ thousands)	Three months ended March 31, 2006	Year ended December 31, 2005
Balance, beginning of period	$3,047	$ 4,636
Trust unit rights incentive plan (non-cash) – exercised	(519)	(4,629)
Trust unit rights incentive plan (non-cash) – expensed	1,187	3,040
Balance, end of period	$3,715	$ 3,047

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, 2006, a total of 2,576,000 rights pursuant to the Trust Unit Rights Incentive Plan ("Rights Plan") at an average exercise price of $44.35 were outstanding. This represents 2.1% of the total trust units outstanding of which 526,000 rights with an average exercise price of $32.89 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, 2006 reduced the exercise price of the outstanding rights by $0.50 per trust unit effective July 2006.

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

	Three months ended March 31, 2006		Year ended December 31, 2005	
	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	2,621	$42.80	2,401	$34.33
Granted	198	56.55	1,125	53.07
Exercised	(210)	34.07	(805)	30.72
Cancelled	(33)	48.67	(100)	37.15
End of period	2,576	44.35	2,621	42.80
Rights exercisable at the end of the period	526	$32.89	643	$32.46

(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 $1,187,000 ($0.01 per unit) related to the rights issued since January 1, 2003 have been charged to general and administrative expense during the three months ended March 31, 2006 (2005 – $662,000, $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)	2006	2005
Weighted average units	118,221	104,269
Dilutive impact of rights	504	508
Diluted trust units	118,725	104,777

5. FINANCIAL INSTRUMENTS

The Fund's financial instruments presented on the balance sheet consist of accounts receivable, other current assets, current liabilities and long-term debt.

The carrying value of accounts receivable, current liabilities and outstanding bank credit facility balances approximate their fair value. Other current assets are comprised of prepaid expenses and marketable securities. The marketable securities are carried on the balance sheet at the lower of cost and fair value. The fair value of the marketable securities at March 31, 2006 exceeded the cost of these securities by $13,890,000. The Fund has US$54,000,000 of senior unsecured notes with fixed rate debt and a fair value of $61,486,000 at March 31, 2006. In addition, the Fund has US$175,000,000 of senior unsecured notes with fixed rate debt that was converted to CDN$268,328,000 floating rate debt through a cross-currency swap with a syndicate of financial institutions. At March 31, 2006 the fair value of the senior unsecured note was $210,379,000.

The estimated fair values have been determined based on available market information and appropriate valuation methods. The actual amounts realized may differ from these estimates.

(a) Derivative Financial Instruments

The Fund uses certain derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. The fair values of these instruments are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the instruments outstanding as at March 31, 2006 with reference to forward prices and market valuations provided by independent sources.

The fair values of derivative financial instruments are as follows:

Interest Rate and Cross Currency Swaps

The Fund has entered into interest rate swaps on $75,000,000 of notional debt at rates varying from 3.97% to 4.12% before banking fees that are expected to range between 0.60% and 1.15%. These interest rate swaps mature between June 2006 and January 2007. The fair value of the $75,000,000 interest rate swaps as at March 31, 2006 represents an unrealized cost of $87,000. These swaps have been designated as hedges for accounting purposes.

The fair value of the cross currency swap related to the US$175,000,000 senior unsecured notes as at March 31, 2006 represents an unrealized cost of $66,128,000 whereas the fair value of the underlying debt instrument as at March 31, 2006 represents an unrealized gain of $57,949,000. The cross currency swap has been designated as a hedge for accounting purposes.

Subsequent to March 31, 2006 the Fund entered into an interest rate swap on $50,000,000 of notional debt at a rate of 4.607%. This swap is effective June 2006 and matures June 2011. It has been designated as a hedge for accounting purposes.

Crude Oil Instruments

The Fund has financial contracts in place on its crude oil production as described below. Effective December 31, 2005, the Fund elected to stop designating commodity contracts as qualified hedges.

The following table summarizes the Fund's crude oil risk management positions at April 26, 2006:

	Daily Volumes	WTI US$/bbl		
	bbls/day	Sold Call	Purchased Put	Sold Put
Term				
April 1, 2006 – June 30, 2006				
3-way option	1,500	$45.80	$31.50	$27.50
Put*	1,500	–	$41.50	–
Put	1,500	–	–	$35.00
April 1, 2006 – June 30, 2006				
Costless Collar*	1,500	$35.35	$30.00	–
Costless Collar*	1,500	$37.00	$30.00	–
April 1, 2006 – December 31, 2006				
Put*	1,500	–	$50.00	–
Put	1,500	–	–	$41.00
April 1, 2006 – December 31, 2006				
Put*	1,500	–	$53.00	–
Put	1,500	–	–	$43.00
April 1, 2006 – December 31, 2006				
Put*	1,500	–	$53.00	–
Put	1,500	–	–	$43.00

* Financial contracts that were treated as hedges during 2005, however the Fund elected to stop designating these contracts as hedges as of December 31, 2005

The Fund did not enter into any new contracts in the first quarter of 2006.

Natural Gas Instruments

The Fund has physical and financial contracts in place on its natural gas production as described below. Effective December 31, 2005, the Fund elected to stop designating commodity contracts as qualified hedges.

The following table summarizes the Fund's natural gas risk management positions at April 26, 2006:

		AECO CDN$/Mcf			
	Daily Volumes MMcf/day	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term					
April 1, 2006 – October 31, 2006					
Swap*	9.5	–	–	–	$5.47
Swap*	4.8	–	–	–	$5.25
Swap*	4.8	–	–	–	$5.24
Swap*	4.8	–	–	–	$5.28
April 1, 2006 – October 31, 2006					
Put*	9.5	–	$7.38	–	–
Put*	9.5	–	$7.38	–	–
Put*	9.5	–	$7.38	–	–
2006 - 2010					
Physical (escalated pricing)	2.0	–	–	–	$2.52

* Financial contracts that were treated as hedges during 2005, however the Fund elected to stop designating these contracts as hedges as of December 31, 2005

The Fund did not enter into any new contracts in the first quarter of 2006.

Electricity Instrument

The Fund has entered into an electricity swap contract that has fixed the price of electricity on 5MWh of Alberta Power Pool electricity consumption at $49.99/MWh from April 1, 2006 to December 31, 2006. This has been designated as a cash flow hedge and the fair value of this instrument as at March 31, 2006 is an unrealized gain of $382,000. Proceeds or costs realized from the electricity hedge are recognized as operating costs.

BOARD OF DIRECTORS

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Calgary, Alberta

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Corporate Director
Calgary, Alberta

Gordon J. Kerr
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EnerMark Inc.
Calgary, Alberta

Robert L. Normand[6][9]
Corporate Director
Rosemere, Québec

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Corporate Director
Canmore, Alberta

W.C. (Mike) Seth[7]
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Calgary, Alberta

Donald T. West[7][12]
Corporate Director
Calgary, Alberta

Harry B. Wheeler[5][8]
President
Colchester Investments Ltd.
Calgary, Alberta

Robert L. Zorich[4][11]
Managing Director
EnCap Investments L.P.
Houston, Texas

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

OFFICERS

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Garry A. Tanner
Executive Vice President & Chief Operating Officer

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Senior Vice President, Corporate Services

Ian C. Dundas
Senior Vice President, Business Development

Eric P. Tremblay
Senior Vice President, Capital Markets

Robert J. Waters
Senior Vice President & Chief Financial Officer

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Vice President, Investor Relations

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Vice President, Operations

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Vice President, General Counsel & Corporate Secretary

Daniel M. Stevens
Vice President, Development Services

Wayne G. Ford
Controller, Operations

Jodine J. Jenson Labrie
Controller, Finance

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS RESOURCES FUND

EnerMark Inc.
Enerplus Resources Corporation
Enerplus Oil & Gas Ltd.
Enerplus Commercial Trust
Enerplus Resources (USA) Corporation

LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Calgary, Alberta

AUDITORS

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CO-TRANSFER AGENT

Mellon Investor Services L.L.C.
Ridgefield, New Jersey

INDEPENDENT RESERVE ENGINEERS

Sproule Associates Limited
Calgary, Alberta

GLJ Petroleum Consultants
Calgary, Alberta

DeGolyer and MacNaughton
Dallas, Texas

STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

Toronto Stock Exchange: ERF.un
New York Stock Exchange: ERF

ABBREVIATIONS

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

enerPLUS
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