FORM 6-K

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Report of Foreign Private Issuer
Pursuant to Rule 13a-16 or 15d-16 of
The Securities Exchange Act of 1934

For the month of August 2002 – Enerplus Resources Fund – Press Release –2nd ***Quarter Interim Financial Statements of Enerplus Resources Fund***

ENERPLUS RESOURCES FUND
(Translation of registrant's name into English)

Dome Tower - 3000 – 333 – 7th Avenue S.W., Calgary, Alberta – Canada – T2P 2Z1
(Address of principal executive offices)

[Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F.................................. Form 40-FX

[Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes.................. No......X.........

[If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g-3-2(b): 82-.........

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENERPLUS RESOURCES FUND
(Registrant)

Date August 20, 2002 By .... CHRISTINA MEEUWSEN CORPORATE SECRETARY
(Signature)*

* Print the name and title of the signing officer under his signature

EXPLANATORY NOTE: Attached as Exhibit A to this Form 6-K is a copy of the 2nd Quarter Interim Financial Statements issued by Enerplus Resources Fund.

SECOND QUARTER SIX MONTHS ENDED JUNE 30, 2002

EXHIBIT "A"

COMBINED FINANCIAL AND OPERATING RESULTS

For the six months ended June 30,	2002	2001[1]
OPERATING		
Average Daily Volumes:		
Crude oil (bbls/day)	**22,892**	25,276
NGLs (bbls/day)	**4,403**	4,888
Natural gas (Mcf/day)	**207,519**	205,335
Total (BOE/day) (6:1)	**61,882**	64,387
% Natural gas	**56%**	53%
Reserve Life Index (years)[3]	**14.0**	13.7

	CDN$		US$[2]	
For the six months ended June 30,	**2002**	2001[1]	**2002**	2001[1]
Average Selling Price Pre-Hedging				
Crude oil (per bbl)	**$ 31.74**	$ 33.62	**$ 20.17**	$ 21.91
NGLs (per bbl)	**21.75**	39.67	**13.82**	25.85
Natural gas (per Mcf)	**3.48**	7.22	**2.21**	4.71
Currency exchange rate (CDN$ to US$)	**$ 0.6354**	$ 0.6517	**$ 0.6354**	$ 0.6517
FINANCIAL (combined basis, unaudited) ($000)				
Oil and gas sales before hedging	**$ 279,159**	$ 457,532	**$ 177,380**	$ 298,175
Proceeds (cost) of hedging	**(2,037)**	(6,593)	**(1,295)**	(4,297)
Royalties	**59,531**	108,724	**37,826**	70,856
Operating costs	**61,164**	64,576	**38,864**	42,084
Operating netback	**156,427**	277,639	**99,395**	180,938
General and administrative	**6,733**	6,703	**4,279**	4,369
Management fees	**6,355**	7,203	**4,038**	4,694
Interest expense, net	**7,229**	10,322	**4,593**	6,727
Capital taxes	**2,656**	2,798	**1,688**	1,824
Site restoration and abandonment	**2,107**	1,257	**1,339**	819
Funds flow from operations	**131,347**	249,356	**83,458**	162,505
Cash withheld for debt reduction	**$ 29,999**	$ 34,451	**$ 19,061**	$ 22,452

(1) The 2001 operating and financial information reflects the combined results of Enerplus and EnerMark as if the Merger had been effective January 1, 2001. Combined information provides a historical perspective of the capabilities of the combined entity. This information is also relevant as both Enerplus Resources Fund and EnerMark Income Fund have been managed by the same management group since inception. **This information is unaudited and does not conform to Canadian Generally Accepted Accounting Principles.**

(2) All $US amounts shown in the table above were converted using the Canadian to U.S. dollar exchange rate for the applicable periods as indicated within the table.

(3) Calculated at December 31 of prior year.

Message to Unitholders

HIGHLIGHTS:

In am pleased to report that second quarter results for Enerplus Resources Fund were in line with our outlook for this period. Commodity prices strengthened over first quarter levels resulting in a 33% increase in cash flow and a corresponding 24% increase in cash distributions payable to unitholders. We continue to apply a portion of the Fund's cash flow, approximately $18 million in the second quarter, to debt repayment incurred as a result of capital development activities.

The most significant event that occurred during the quarter was the closing of a US$175 million private placement debt issue. This offering was extremely successful with 11 U.S. institutional investors participating. The offering not only diversifies the Fund's capital sources, but also provides a new source of long-term funding at attractive rates. As a result of this offering, Enerplus now has a stronger financial capacity and is ideally positioned to pursue acquisition opportunities as they become available. Although we did not close any new significant acquisitions for the Fund in the second quarter, recent activities are providing greater potential opportunities as we remain disciplined and focused in this area.

Operationally, Enerplus performed very well during the quarter with production volumes averaging 61,146 BOE per day, in line with the 2002 target of 61,000 BOE per day. Operating expenses continue to be lower than anticipated and general and administrative expenses have held constant from the first quarter. Capital expenditures during the second quarter totalled $21 million, lower than anticipated due to project delays caused by poor weather. However, as a result of these delays, planned 3rd and 4th quarter activities have been increased to ensure we remain on track with our target. Enerplus plans to invest approximately $75 million in development activity in the second half of the year drilling in excess of 175 wells, primarily in the shallow gas areas of Hanna Garden, Fox Valley, Medicine Hat and Bantry/Verger. We continue to review the Fund's asset portfolio in order to determine where the greatest opportunities exist to add value not only through development activity, but also through acquisitions of additional working interests in existing areas and selected divestments.

Gordon J. Kerr
President & Chief Executive Officer

2002 CASH DISTRIBUTIONS PER UNIT

Production Month	Payment Month	CDN$	US$
January	March	$ 0.20	$ 0.13
February	April	0.20	0.13
March	May	0.28	0.18
First Quarter total		**$ 0.68**	**$ 0.44**
April	June	0.28	0.18
May	July	0.28	0.18
June	August	0.28	0.18*
Second Quarter total		**$ 0.84**	**$ 0.54**

*Using an estimated Canadian/US dollar exchange rate of 1.58

UNIT TRADING SUMMARY

Three months ended June 30, 2002	Toronto Stock Exchange ERF.un - (CDN$)	New York Stock Exchange ERF - (US$)
High	$ 28.19	$ 18.59
Low	$ 25.15	$ 15.92
Close	$ 28.19	$ 18.55
Volume	10,103,638	6,636,100

DEVELOPMENT ACTIVITIES

Enerplus' development activity is designed to help offset the Fund's natural reservoir decline through the exploitation of existing assets. These activities add value to the Fund through the addition of new production volumes and incremental reserves. During the second quarter, Enerplus continued with its development program, however, activities were reduced due to project delays caused by wet weather. Capital expenditures totalled approximately $21 million with 67 new wells (gross) drilled with a 99% success rate. The majority of these wells were drilled in the shallow natural gas area of Medicine Hat and the non-operated oil property of Jenner. Third quarter spending levels will be higher than anticipated due to the carry over of those activities not concluded during the second quarter and we remain on target to meet our capital expenditure budget of approximately $130 million in 2002.

2002 SECOND QUARTER DRILLING ACTIVITY

	Crude Oil Wells		Natural Gas Wells		Dry & Abandoned Wells		Total Wells	
Drilling Activity	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	14.0	3.0	51.0	47.1	1.0	0.5	66.0	50.6
Saskatchewan	1.0	0.3	-	-	-	-	1.0	0.3
Total	**15.0**	**3.3**	**51.0**	**47.1**	**1.0**	**0.5**	**67.0**	**50.9**

Success Rate: 99%

JOARCAM, ALBERTA (OPERATED, W.I. 80%)

The Joarcam area, located southeast of Edmonton, Alberta, is the Fund's largest crude oil producing property. An aggressive capital program designed to enhance the light oil production from the Viking reservoir in this area continued in the first quarter of 2002 with 11 Viking oil wells drilled, completed and tied-in. Extensive upgrade and expansion of area infrastructure was completed in the second quarter to handle the incremental production from the new wells and to improve the efficiency of existing production. Fluids that were previously being processed at non-operated facilities are now being directed to Enerplus owned and operated facilities.

Joarcam produced an average of 2,987 BOE/day net to the Fund during the second quarter, which was comprised of 1,839 bbls/day of crude oil and natural gas liquids and 6.9 MMcf/day of natural gas. Production was down slightly from the first quarter due to the extensive work being carried out on the infrastructure in the area. Including the new wells on production in June, the exit production rate for the second quarter was 3,900 BOE/day net with incremental oil production from these new wells approximately 700 bbls/day. Total capital expenditures at Joarcam are approximately $14 million year to date.

The Fund has plans to drill six additional infill Viking oil wells in the fourth quarter of 2002 as well as five non-associated natural gas wells to follow up on the successful Belly River gas well that was drilled in the second quarter 2002.

MEDICINE HAT NORTH, ALBERTA (OPERATED, W.I. 100%)

Enerplus initiated its shallow gas development program for 2002 during the second quarter with the commencement of a 50 well development program on this property. This activity is a follow up to the successful 13 well infill program completed late in the fourth quarter of 2001. Approximately half of the wells in the 50 well program were drilled in the second quarter with the remaining wells to be drilled in the third quarter. Additional compression capacity will be installed during the third quarter to handle the anticipated 2.7 MMcf/day of production from this infill program. The Medicine Hat North property produced an average of 2.2 MMcf/day during the second quarter.

GLENEATH UNIT, SASKATCHEWAN (OPERATED, W.I. 81%)

Enerplus continued to increase production from this light oil property during the second quarter by fracture stimulating an additional 12 wells. Combined with the activities concluded in the first quarter, 37 oil wells have now been fracture stimulated year to date. The average incremental production volume from these re-stimulations is approximately 300 BOE/day net to the Fund. Enerplus has scheduled 12 additional re-stimulations to be carried out in the third quarter of 2002 to complete this program and will also initiate an infill drilling program of up to ten wells during the third quarter. Production from the Gleneath Unit averaged 1,049 BOE/day net to the Fund during the second quarter, an increase of 29% over first quarter production levels.

BENJAMIN, ALBERTA (NON-OPERATED, W.I. 20%)

During the second quarter of 2002, Enerplus participated in the drilling of two successful natural gas wells in this non-operated, deep foothills natural gas property. These wells were planned for 2002 as a result of the completion of additional pipeline and processing capabilities in 2001, ensuring that future gas development could be realized. The first well drilled, in which the Fund has a 6.5% working interest, encountered three Turner Valley zones which were completed and production tested at a rate of 18 MMcf/day gross (1.2 MMcf/day net) to the Fund. This well was subsequently placed on production at 15 MMcf/day. The second well, in which Enerplus has a 25.8% working interest, was drilled later in the quarter and will be completed, tested and placed on production in the third quarter. It is anticipated that this well will produce approximately 15 MMcf/day gross or 3.9 MMcf/day net to the Fund. The Benjamin area produced an average of 10.9 MMcf/day net to the Fund during the second quarter.

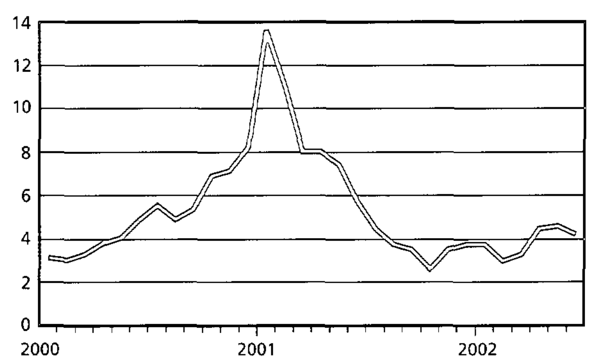
JENNER, ALBERTA (NON-OPERATED, W.I. 20%)

During the second quarter, Enerplus participated in six successful horizontal oil wells to more fully develop the Glauconite oil pool at Jenner. These wells were completed and placed on production providing incremental production of 108 bbls/day net to the Fund. This horizontal development drilling program will be completed in the third quarter with four additional wells being drilled. Oil production from this area averaged 330 bbls/day net to the Fund during the second quarter of 2002.

MARKETING

NATURAL GAS

AECO 30 Day Spot Price
(CDN$/Mcf)



Canadian natural gas prices in the second quarter of 2002 marked a 33% increase over the first quarter of the year as the AECO monthly index price rose from CDN$3.34/Mcf in the first quarter to CDN$4.43/Mcf in the second quarter of 2002. This strength in natural gas prices was unexpected given the mild end to winter and the high natural gas storage levels. In the U.S. the NYMEX natural gas price averaged US$3.37/Mcf in the second quarter of 2002 compared to US$2.38/Mcf in the first quarter of the year, an increase of 42%.

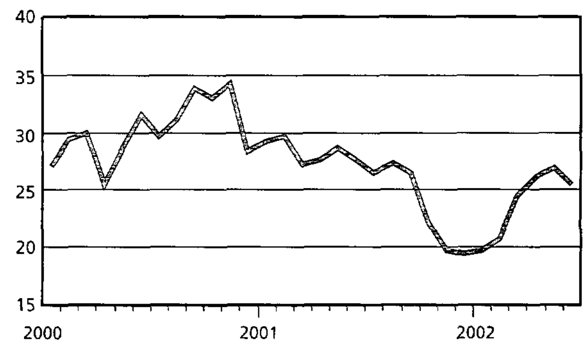
Although there was a slight recovery in North American industrial and commercial demand, natural gas markets were largely supported by the strength of the crude oil market. Increasing crude oil prices carried the price of competing fuels, such as natural gas, higher. Many non-commercial gas traders and funds were caught by surprise, adding further support for prices as they scrambled to cover short positions. In the near term, weather continues to have a major impact on the market, with air conditioning energy requirements on the east coast adding price support, while greater rainfall and hydroelectric capacity on the west coast offset this by reducing demand for natural gas.

The current forward market anticipates some near-term natural gas price weakness. Recently, Canadian natural gas prices have not kept pace with U.S. natural gas prices. Canadian natural gas prices have been under pressure as exports to the U.S. west coast have been reduced by competing hydroelectric power, while Canadian exports to the central and eastern regions of the U.S. have been restricted by pipeline capacity and a lack of Canadian storage capacity.

Over the mid-to longer-term, supply constraints caused by the recent reduction in drilling activity, reduction in capital investment, and lack of exploration success are expected to support natural gas prices, especially in the event of an economic recovery in North America.

CRUDE OIL

WTI Crude Oil Price
(US$/bbl)



Throughout the second quarter of 2002, world crude oil prices continued to be influenced by political tension in the Middle East and OPEC's quota management. West Texas Intermediate ("WTI") benchmark crude averaged US$26.25/bbl for the second quarter, an increase of 21% over the US$21.64/bbl WTI price experienced in the first quarter of the year.

Experts estimate that current oil prices reflect a "war premium" of US$4 – $6 per barrel. In the near term, prices may continue to be supported at these levels, with no end in sight for the Middle Eastern tensions, and with OPEC electing to extend their production quotas.

Heavy Oil differentials (price discounts to account for the increased refining costs of heavy oil) remained in the US$6.00 per barrel range in the second quarter of 2002, with seasonal demand for asphalt increasing the requirement for heavy oil feedstock, and adherence to quotas reducing the supply of OPEC heavy oil in the North American marketplace. This is a significant improvement over the US$13.00/bbl heavy oil differential experienced in 2001. Continued weakness in the Canadian dollar continues to benefit the Fund's crude oil revenues as the majority of Canada's crude oil is priced with reference to the US$ benchmarks.

MANAGEMENT DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of the financial results of Enerplus Resources Fund ("Enerplus" or the "Fund") should be read in conjunction with:

- the MD&A and Audited Consolidated Financial Statements as at and for the years ended December 31, 2001 and 2000; and
- the Interim Unaudited Consolidated Financial Statements as at and for the three months ended March 31, 2002 and 2001 and as at and for the three and six months ended June 30, 2002 and 2001.

All amounts are stated in Canadian dollars unless otherwise specified. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. In accordance with Canadian practice, production volumes, reserve volumes and revenues are reported on a gross basis, including Crown and freehold royalties, unless otherwise indicated.

SECOND QUARTER 2002 HIGHLIGHTS

- The Fund paid $0.84 per trust unit ($58.7 million) in cash distributions to unitholders with respect to the quarter and retained $0.26 per trust unit ($18.4 million) to reduce debt incurred on development spending.
- During the second quarter of 2002, Enerplus diversified its debt portfolio by repaying a portion of its bank debt with the proceeds raised through the issuance of US$175 million senior, 12-year amortizing unsecured notes with a coupon rate of 6.62%.
- The Fund experienced significantly lower prices for its natural gas and NGL's in the second quarter of 2002 when compared to the second quarter of 2001. Natural gas prices declined 32% and NGL prices declined 29% during this time period. These price declines were offset marginally by the 6% increase in the price of crude oil over the same period.
- Operating costs were $5.54/BOE for the three months ended June 30, 2002 compared to $5.68/BOE for the same period in 2001. Most of this decrease in operating costs can be attributed to lower electricity costs during 2002.
- Enerplus continued with its active development program, investing $21.4 million in development drilling and facilities enhancements for the three months ended June 30, 2002. During the quarter, Enerplus drilled 67 gross wells (51 net wells) with a 99% success rate.

IMPORTANT INFORMATION REGARDING COMPARATIVE FINANCIAL STATEMENTS

On June 21, 2001, the respective unitholders of the EnerMark Income Fund ("EnerMark") and the Enerplus Resources Fund overwhelmingly approved a merger combining the two funds ("the Merger"). As the former unitholders of EnerMark held approximately 69% of the outstanding trust units of the combined fund at the date of acquisition, the Merger was accounted for using the reverse takeover form of the purchase method of accounting for business combinations. For accounting purposes, EnerMark acquired Enerplus effective June 21, 2001 and continues as Enerplus Resources Fund which has a 16-year history, market recognition and a listing on the New York Stock Exchange.

With the reverse takeover form of the purchase method of accounting, the unaudited consolidated financial statements presented herein include the accounts of EnerMark and Enerplus as at, and for the three and six months ended June 30, 2002. The historical comparative financial information for the year 2001 presented in the interim unaudited consolidated financial statements includes the results of EnerMark for the entire period, and the results of Enerplus for the 10 day period from the date of the Merger to June 30, 2001.

RESULTS OF OPERATIONS

Production

Daily production averaged 61,146 BOE/day during the three months ending June 30, 2002, representing a 31% increase over production volumes of 46,789 BOE/day for the same period in 2001. The increase is attributed primarily to the reverse takeover of Enerplus by EnerMark as the financial statements do not reflect the results of Enerplus prior to the effective date of June 21, 2001.

Compared to the first quarter of 2002, Enerplus' production decreased 2% to 61,146 BOE/day from 62,626 BOE/day. Crude oil and NGL production remained relatively constant for the first half of the year as natural reservoir declines were offset by production gains from development activity and a $20.5 million acquisition of an additional working interest in the Medicine Hat Glauc "C" property in March 2002. Natural gas production decreased to 203,370 Mcf/day for the quarter ending June 30, 2002 from 211,713 Mcf/day for the quarter ending March 31, 2002 as a result of reservoir declines and facility maintenance on both operated and non-operated facilities.

Enerplus' average production portfolio for the three months ended June 30, 2002 was weighted 56% natural gas, 37% crude oil, and 7% natural gas liquids. Average production volumes are outlined below:

	Three months ended June 30,			Six months ended June 30,		
Daily Sales Volumes	**2002**	2001	% change	**2002**	2001	% change
Natural gas (Mcf/day)	**203,370**	149,201	36%	**207,519**	150,775	38%
Crude oil (bbl/day)	**22,820**	17,986	27%	**22,892**	18,383	25%
Natural gas liquids (bbl/day)	**4,431**	3,936	13%	**4,403**	3,534	25%
Total daily sales (BOE/day)	**61,146**	46,789	31%	**61,882**	47,046	32%

PRICING AND PRICE RISK MANAGEMENT

The average price that Enerplus received for its natural gas (before hedging) decreased 32% from $5.81/Mcf for the three months ending June 30, 2001 to $3.93/Mcf for the same period in 2002. In comparison, during this time period, the AECO monthly index price decreased 37% from $7.08/Mcf in 2001 to $4.43/Mcf in 2002 and the NYMEX index price decreased 29% from US$4.78/Mcf in 2001 to US$3.37/Mcf in 2002.

The average price that Enerplus received for its crude oil (before hedging) increased 6% from CDN$33.18/bbl for the second quarter of 2001 to CDN$35.18/bbl in the same quarter in 2002, despite a comparative 6% decrease in the price of benchmark West Texas Intermediate (WTI) crude oil. Enerplus benefited from a narrower price differential on heavier blends of crude oil during the quarter. For example, the Lloydminster Blend heavy crude oil price differential narrowed from US$11.46/bbl in the second quarter of 2001 to US$5.96/bbl in the second quarter of 2002.

The realized prices for natural gas liquids ("NGL's") decreased 29% from the second quarter of 2001 to average $25.28/bbl for the second quarter of 2002, reflecting the influence of lower natural gas prices.

	Three months ended June 30,			Six months ended June 30,		
Average Selling Price	**2002**	2001	% change	**2002**	2001	% change
Natural gas (Mcf/day)	**$ 3.93**	$ 5.81	-32%	**$ 3.48**	$ 7.20	-52%
Crude oil (bbl/day)	**$ 35.18**	$ 33.18	6%	**$ 31.74**	$ 33.20	-4%
Natural gas liquids (bbl/day)	**$ 25.28**	$ 35.44	-29%	**$ 21.75**	$ 40.36	-46%
Total daily sales (BOE/day)	**$ 27.98**	$ 34.25	-18%	**$ 24.92**	$ 39.08	-36%

	Three months ended June 30,			Six months ended June 30,		
Benchmark Pricing	**2002**	2001	% change	**2002**	2001	% change
AECO (30 day) natural gas (per Mcf)	**$ 4.43**	$ 7.08	-37%	**$ 3.89**	$ 8.99	-57%
NYMEX natural gas (US$ per Mcf)	**$ 3.37**	$ 4.78	-29%	**$ 2.88**	$ 6.03	-52%
WTI crude oil (US$ per bbl)	**$ 26.25**	$ 27.96	-6%	**$ 23.95**	$ 28.35	-16%
Currency $1CDN in US$	**$ 0.6436**	$ 0.6489	-1%	**$ 0.6354**	$ 0.6517	-3%

Enerplus has continued to implement hedging transactions in accordance with its commodity price risk management program during the second quarter. The program is intended to provide a measure of stability to the Fund's cash distributions as well as ensure Enerplus realizes positive economic returns from its capital development and acquisition activities. Enerplus' commodity risk management program at June 30, 2002 is described in detail in Note 5 to the financial statements.

For the three months ended June 30, 2002, Enerplus realized a hedging loss of $1.6 million on natural gas and $0.5 million on crude oil as a result of its price risk management program. This realized loss is mainly due to an improvement in the markets for natural gas and crude oil during the period. The mark-to-market value of Enerplus' forward commodity price contracts at June 30, 2002 represented an unrealized loss of $7.0 million for natural gas and an unrealized loss of $4.9 million for crude oil.

REVENUES

Crude oil and natural gas revenues, including hedging costs, were $153.6 million for the three months ended June 30, 2002, which was 6% higher than the $144.5 million reported for the same period in 2001. The increased revenue was due primarily to the increase in production volumes resulting from the reverse takeover of Enerplus on June 21, 2001 offset by a reduction in natural gas prices for the second quarter of 2002 compared to 2001.

Analysis of Sales Revenues ($millions)	Crude Oil	NGL	Natural Gas	Total
2001 - 2nd Quarter Revenues	$ 52.7	$ 12.7	$ 79.1	$144.5
Price variance	4.2	(3.6)	(33.9)	(33.3)
Volume variance	14.5	1.1	27.5	43.1
Hedging cost variance	1.1	-	(1.8)	(0.7)
2002 - 2nd Quarter Revenues	**$ 72.5**	**$ 10.2**	**$ 70.9**	**$ 153.6**

ROYALTIES

Royalties decreased from $35.1 million or 24% of oil and gas sales for the three months ended June 30, 2001 to $33.1 million or 21% for the three months ended June 30, 2002. The decrease in the royalty rate is attributable to lower commodity reference prices which are used to determine prevailing royalty rates.

OPERATING EXPENSES

Operating expenses increased to $30.9 million for the three months ended June 30, 2002 from $24.2 million for the same period in 2001, due mainly to the higher production volumes associated with the reverse takeover of Enerplus. Operating costs were $5.54/BOE for the three months ended June 30, 2002 compared to $5.68/BOE for the same period in 2001. The decrease in operating costs per BOE is primarily a result of lower electricity costs during 2002.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative ("G&A") expenses were $3.4 million for the three months ended June 30, 2002 compared to $2.6 million for the same period in 2001. G&A costs were $0.60/BOE for the three months ended June 30, 2002 compared to $0.61/BOE for the same period in 2001. The G&A costs for the second quarter of 2002 included several one-time costs associated with relocating our Calgary head office.

In accordance with the full cost method of accounting, Enerplus capitalized $2.0 million or 25% of gross G&A costs for the three months ended June 2002 compared to $1.4 million or 24% for the same period in 2001. The majority of these capitalized costs represent compensation costs for staff involved in development and acquisition activities and the capitalized portion is consistent with prior periods.

MANAGEMENT FEES

Six months ended June 30, ($ millions)	2002	2001
Base management fees	$ 4.0	$ 4.5
Performance fees	2.4	-
Total management fees	$ 6.4	$ 4.5

Base management fees, which are now calculated based on 2.75% of net operating income, decreased to $4.0 million or $0.36/BOE in the first half of 2002 from $4.5 million or $0.52/BOE for the same period in 2001. The decrease is a result of lower net operating income.

The performance fee can range between 0% and 4% of the Fund's annual operating income based on the total return of the Fund and the relative performance compared to other senior oil and gas trusts. Although the performance fee is determined on December 31, 2002, management has accrued a performance fee based on the fact that, had the calculation been performed at June 30, 2002, the performance fee for 2002 would be 1.5% of net operating income. The $2.4 million is an estimate which may increase or decrease throughout the remainder of the year until year end, at which time the performance fee is calculated and finalized.

INTEREST EXPENSE

Interest expense for the three months ended June 30, 2002 was $4.2 million, an increase of 6% from the comparable period of 2001. The increase is the result of the additional bank debt attributable to the reverse takeover and capital spending of Enerplus, offset by a reduction in interest rates of approximately 2.4%.

The principal and interest payments with respect to the US$175 million senior unsecured debentures were swapped to Canadian dollar debt and Canadian floating rates set at the prevailing three month Canadian banker's acceptances rate plus 1.18%, on a principal amount of CDN$268.3 million until June 19, 2010 and on declining amounts, thereafter, as the outstanding principal is paid down. As at June 30, 2002, this swap instrument had a positive mark-to-market value of $0.1 million.

Also in connection with the debt offering, Enerplus entered into interest rate swaps that fixed the interest rate on a notional $50 million of debt for three years. A similar swap was entered into in the first quarter of 2002 resulting in the following fixed rate positions as at June 30, 2002:

Notional amount	Swap term	Fixed rate [1]
$25 million	To January 18, 2005	3.89%
$25 million	To June 3, 2005	4.70%
$25 million	To June 4, 2005	4.65%

[1] Before banking fees that are expected to range between 0.85% and 1.05%.

As at June 30, 2002, the $75 million in floating to fixed interest rate swaps had a negative mark-to-market value of $0.3 million.

DEPLETION, DEPRECIATION AND AMORTIZATION

Depletion, depreciation and amortization increased to $51.8 million for the three months ended June 30, 2002 from $40.4 million for the same period in 2001. Additional production, as a result of the reverse takeover of Enerplus, increased the overall depletion, depreciation and amortization expense, however the depletion, depreciation and amortization rate per BOE was lower at $9.31/BOE for the three months ended June 30, 2002 versus $9.48/BOE for the same period in 2001.

TAXES

For the three months ended June 30, 2002, a future income tax recovery of $1.7 million was recorded in income. Under Canadian generally accepted accounting principles, the Fund does not recognize any future income taxes, as taxable income is distributed to unitholders in the form of taxable distributions. However, the Fund's operating companies are required to account for future income taxes. Future income taxes for the operating companies are dependant upon the method by which funds are transferred to the Fund from the operating companies. The future income tax recovery results from taxable distributions, which can take the form of interest or royalties, being transferred from the operating companies to the Fund's unitholders.

NETBACKS

Netbacks per BOE of production (6:1)	Three months (Q2)		Six months (YTD)	
for the period ended June 30, 2002	**2002**	2001	**2002**	2001
Oil and gas sales	**$ 27.60**	$ 33.92	**$ 24.74**	$ 38.58
Royalties	**(5.94)**	(8.26)	**(5.32)**	(9.70)
Operating	**(5.54)**	(5.68)	**(5.46)**	(5.45)
Operating netback per BOE	**$ 16.12**	$ 19.98	**$ 13.96**	$ 23.43
General and administrative	**(0.60)**	(0.61)	**(0.60)**	(0.56)
Management fees	**(0.84)**	(0.46)	**(0.57)**	(0.52)
Net interest	**(0.72)**	(0.83)	**(0.64)**	(0.91)
Capital taxes	**(0.27)**	(0.24)	**(0.24)**	(0.27)
Total cash netback per BOE	**$ 13.69**	$ 17.84	**$ 11.91**	$ 21.17

NET INCOME AND FUNDS FLOW FROM OPERATIONS

Net income for the three months ended June 30, 2002 was $26.1 million or $0.37 per trust unit, down 55% from $58.5 million or $1.30 per trust unit for the same period in 2001. After adding back non-cash expenses, the resultant Funds Flow from Operations was $75.2 million for the quarter ended June 30, 2002 or $1.08 per trust unit compared to $75.6 million or $1.67 per trust unit for the same period in 2001. This difference in funds flow per unit is primarily due to additional units being issued as a result of the Merger, combined with a decrease in natural gas revenues during the second quarter of 2002 compared to the same period in 2001.

Management monitors the Fund's distribution payout policy with respect to forecast cash flows, debt levels, and spending plans. Management is 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.

With respect to the second quarter of 2002, Enerplus distributed $58.7 million, or $0.84 per trust unit in cash distributions to unitholders and withheld $18.4 million or $0.26 per trust unit for debt reduction. For the six month period, Enerplus has distributed $106.1 million, or $1.52 per trust unit and withheld $30.0 million or $0.43 per trust unit for debt reduction.

The table on the following page reconciles Enerplus' "Funds Flow from Operations" as per the Statement of Cash Flows with the cash available for distribution to unitholders.

Reconciliation of cash available for distribution for the period ended June 30,	Three months (Q2) 2002	Three months (Q2) 2001	Six months (YTD) 2002	Six months (YTD) 2001
($ millions except per unit amounts)				
Funds flow from operations	$ 75.2	$ 75.6	$ 131.3	$ 179.7
Cash withheld for debt reduction	(18.4)	(8.6)	(30.0)	(26.6)
Enerplus cash flows	-	16.9	-	16.9
Accruals*	1.9	2.4	4.8	2.3
Cash available for distribution	$ 58.7	$ 86.3	$ 106.1	$ 172.3
Cash available for distribution per trust unit	$ 0.84	$ 1.50	$ 1.52	$ 3.52

* According to the Royalty Agreement with Enerplus Resources Corporation, the royalty paid to the Fund must be on a cash basis. As a consequence, the change in accrued net revenues for the period are added back to funds flow from operations for purposes of this reconciliation.

Cash available for distribution per trust unit of $0.84 for the three months ended June 30, 2002 represents what an Enerplus unitholder will have received from the production for the second quarter of 2002 (paid to unitholders June 20, 2002, July 20, 2002 and August 20, 2002). Cash available for distribution of $1.50 per trust unit for the same period in 2001 represents what an EnerMark unitholder would have received after converting 1 EnerMark unit for 0.173 Enerplus unit pursuant to the terms of the Merger.

CAPITAL EXPENDITURES

During the six months ended June 30, 2002, Enerplus spent $54.9 million (2001- $53.1 million) on capital expenditures prior to acquisitions and divestitures. Capital expenditures are lower than anticipated for the first half of 2002 due to wet spring weather conditions that limited lease and facility access. The Fund expects capital spending to accelerate in the third and fourth quarters and it continues to target annual capital expenditures of approximately $130.0 million excluding acquisitions and divestitures.

For the six months ended June 30, ($millions)	2002	2001
Development drilling and recompletions	$ 30.5	$ 27.8
Plant and facilities	19.8	21.0
Land and seismic	1.7	3.2
Office	2.9	1.1
Total capital spending	54.9	53.1
Acquisitions of oil and gas properties	22.9	2.8
Dispositions of non-core oil and gas properties	(2.1)	(20.0)
Net capital expenditures	$ 75.7	$ 35.9

The following table outlines the development spending by major property:

For the six months ended June 30, ($millions)	2002				2001
	Drilling	Facilities	Other	Total	Total
Joarcam	$ 5.4	$ 8.1	$ 0.1	$ 13.6	$ 2.4
Medicine Hat	1.3	1.7	-	3.0	2.3
Valhalla	2.1	0.6	-	2.7	1.1
Bantry	1.1	1.5	-	2.6	2.8
Hanna/Garden Plains	2.4	(0.5)	-	1.9	16.8
Verger	1.2	0.3	-	1.5	-
Gleneath	1.4	(0.2)	-	1.2	-
Kaybob	0.7	0.4	-	1.1	0.7
Giltedge	-	0.8	-	0.8	1.6
Badger	0.1	0.7	-	0.8	-
Komie	-	0.7	-	0.7	-
Wildhorse Creek	-	-	-	-	2.3
Other	14.8	5.7	4.5	25.0	23.1
Total	$ 30.5	$ 19.8	$ 4.6	$ 54.9	$ 53.1

The Fund continued to pursue and evaluate numerous acquisition opportunities during the second quarter of 2002. No significant transactions were closed during the quarter as the acquisition market continues to be challenging in view of the prices being paid for properties. However, on a positive note, management has recently witnessed an increase in potential opportunities, driven by motivated sellers and a tempering of commodity price expectations. Enerplus will continue to pursue acquisition opportunities while maintaining a focused effort on the development of existing reserves that provide attractive potential economic returns to unitholders.

LIQUIDITY AND CAPITAL RESOURCES

During the second quarter of 2002, Enerplus diversified its debt portfolio by repaying a portion of its bank debt with the proceeds raised through the issuance of US$175 million senior, unsecured notes with a coupon rate of 6.62% priced at par (the "Notes"). The Notes have a final maturity of June 19, 2014, with amortizing payments of 20% per annum on each of the five anniversary dates commencing on June 19, 2010. The Notes provide the Fund with a new source of financing and the assurance of long-term credit commitments at attractive rates.

Concurrent with the issuance of the Notes, Enerplus swapped the US$175 million into Canadian dollar denominated floating rate debt at an exchange rate of 1.5333 for gross proceeds of $268.3 million at a floating interest rate, based on Canadian three month banker's acceptances, plus 1.18%.

The issuance of the Notes and related swap resulted in bank debt as at June 30, 2002 of $172.5 million. When combined with the Canadian equivalent value of the Notes Enerplus' long-term debt as at June 30, 2002 was $440.8 million compared to $412.6 million as at December 31, 2001. This increase largely arises from the acquisition and development of oil and gas properties.

Financial Leverage and Coverage Ratios	**Quarter ended June 30, 2002**	Year ended December 31, 2001
Long-term debt to funds flow from operations	**1.5 x**	1.2 x
Funds flow from operations to interest expense*	**17.4 x**	19.3 x
Long-term debt to long-term debt plus equity	**25%**	23%

* Funds flow from operations to interest expense ratio is based on the first six months of 2002 plus the last six months of 2001.

TRUST UNIT INFORMATION

Enerplus had 69,853,000 trust units and no warrants outstanding at June 30, 2002 compared to 64,562,000 trust units and 2,507,000 warrants at June 30, 2001. The weighted average number of trust units outstanding during the second quarter of 2002 was 69,740,000 (2001- 45,021,000).

TAXABILITY OF DISTRIBUTIONS

In the current commodity price environment, Enerplus expects that approximately 65% of the distributions paid to Canadian unitholders in 2002 will be taxable and the remaining 35% will be treated as a tax deferred return of capital.

FORWARD-LOOKING STATEMENTS

This discussion and analysis contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of Enerplus. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted.

ENERPLUS RESOURCES FUND

CONSOLIDATED BALANCE SHEET

($thousands), (Unaudited)	June 30, 2002	December 31, 2001
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,363	$ 979
Accounts receivable	63,223	100,089
Other current	4,432	4,869
	69,018	105,937
Property, plant and equipment	2,743,200	2,667,504
Accumulated depletion and depreciation	(592,362)	(489,188)
	2,150,838	2,178,316
Deferred charges (Note 4)	1,887	-
	$ 2,221,743	$ 2,284,253
LIABILITIES		
Current liabilities		
Accounts payable	$ 54,367	$ 72,341
Distributions payable to unitholders	19,560	20,860
Payable to related party (Note 3)	4,990	7,915
	78,917	101,116
Long-term debt (Note 4)	440,809	412,589
Future income taxes	325,346	333,560
Accumulated site restoration	57,534	55,403
Deferred credits	5,429	6,591
Payable to related party (Note 3)	1,653	1,909
	830,771	810,052
EQUITY		
Unitholders' capital (Note 2)	1,833,930	1,826,507
Accumulated income	359,988	324,570
Accumulated cash distributions	(881,863)	(777,992)
	1,312,055	1,373,085
	$ 2,221,743	$ 2,284,253
Number of Trust Units outstanding (thousands)	69,853	69,532

ENERPLUS RESOURCES FUND

CONSOLIDATED STATEMENT OF INCOME

($thousands except per unit amounts), (Unaudited)	Three months ended June 30, 2002	Three months ended June 30, 2001	Six months ended June 30, 2002	Six months ended June 30, 2001
REVENUES				
Oil and gas sales	**$ 153,618**	$ 144,465	**$ 277,122**	$ 328,596
Crown royalties	**(24,735)**	(27,452)	**(44,852)**	(65,305)
Freehold and other royalties	**(8,322)**	(7,692)	**(14,679)**	(17,319)
	120,561	109,321	**217,591**	245,972
Interest and other income	**208**	456	**307**	570
	120,769	109,777	**217,898**	246,542
EXPENSES				
Operating	**30,852**	24,199	**61,164**	46,440
General and administrative	**3,368**	2,609	**6,733**	4,734
Management fees (Note 3)	**4,659**	1,943	**6,355**	4,460
Interest (Note 5)	**4,241**	4,013	**7,536**	8,352
Depletion, depreciation and amortization	**51,806**	40,362	**106,250**	80,462
	94,926	73,126	**188,038**	144,448
Income before taxes	**25,843**	36,651	**29,860**	102,094
Capital taxes	**1,478**	1,070	**2,656**	2,272
Future income tax recovery	**(1,686)**	(22,876)	**(8,214)**	(18,366)
NET INCOME	**$ 26,051**	$ 58,457	**$ 35,418**	$ 118,188
Net income per trust unit				
Basic	**$ 0.37**	$ 1.30	**$ 0.51**	$ 2.71
Diluted	**$ 0.37**	$ 1.29	**$ 0.51**	$ 2.70
Weighted average number of units outstanding (thousands)				
Basic	**69,740**	45,021	**69,666**	43,601
Diluted	**69,874**	45,312	**69,762**	43,698

CONSOLIDATED STATEMENT OF ACCUMULATED INCOME

($thousands), (Unaudited)	Three months ended June 30, 2002	Three months ended June 30, 2001	Six months ended June 30, 2002	Six months ended June 30, 2001
Accumulated income, beginning of period	**$ 333,937**	$ 204,032	**$ 324,570**	$ 144,301
Net income	**26,051**	58,457	**35,418**	118,188
Accumulated income, end of period	**$ 359,988**	$ 262,489	**$ 359,988**	$ 262,489

ENERPLUS RESOURCES FUND

CONSOLIDATED STATEMENT OF CASH FLOWS

($thousands), (Unaudited)	Three months ended June 30, 2002	Three months ended June 30, 2001	Six months ended June 30, 2002	Six months ended June 30, 2001
OPERATING ACTIVITIES				
Net income	$ 26,051	$ 58,457	$ 35,418	$ 118,188
Depletion, depreciation and amortization	51,806	40,362	106,250	80,462
Future income tax recovery	(1,686)	(22,876)	(8,214)	(18,366)
Site restoration and abandonment costs incurred	(986)	(326)	(2,107)	(624)
Funds flow from operations	75,185	75,617	131,347	179,660
Decrease (increase) in non-cash operating working capital	4,936	(17,376)	20,040	(28,214)
	80,121	58,241	151,387	151,446
FINANCING ACTIVITIES				
Issue of trust units, net of issue costs	3,582	28,177	6,683	34,592
Cash distributions to unitholders	(50,392)	(87,061)	(102,571)	(159,835)
Increase (decrease) in long-term debt	(2,989)	28,114	28,220	13,557
Payment to related party (Note 3)	(128)	-	(256)	-
Deferred charges	(1,887)	-	(1,887)	-
	(51,814)	(30,770)	(69,811)	(111,686)
INVESTING ACTIVITIES				
Property, plant and equipment	(30,383)	(30,989)	(83,330)	(54,828)
Proceeds on sale of property, plant and equipment	1,920	10,416	2,138	26,826
Corporate acquisitions	-	(6,689)	-	(11,802)
	(28,463)	(27,262)	(81,192)	(39,804)
Increase (decrease) in cash	(156)	209	384	(44)
Cash, beginning of period	1,519	593	979	846
Cash, end of period	$ 1,363	$ 802	$ 1,363	$ 802
Funds flow from operations per unit	$ 1.08	$ 1.67	$ 1.89	$ 4.12
SUPPLEMENTARY CASH FLOW INFORMATION				
Cash income taxes paid	-	-	-	-
Cash interest paid	$ 3,601	$ 3,736	$ 7,384	$ 7,905

CONSOLIDATED STATEMENT OF ACCUMULATED CASH DISTRIBUTIONS

($thousands), (Unaudited)	Three months ended June 30, 2002	Three months ended June 30, 2001	Six months ended June 30, 2002	Six months ended June 30, 2001
Accumulated cash distributions, beginning of period	$ 823,245	$ 523,105	$ 777,992	$ 447,158
Cash distributions	58,618	95,946	103,871	171,893
Accumulated cash distributions, end of period	$ 881,863	$ 619,051	$ 881,863	$ 619,051

SELECTED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(Tabular amounts in thousands of Canadian dollars and thousands of units except per unit amounts)

1. 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, 2001 except as stated below. 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 financial statements for the year ended December 31, 2001. The disclosures provided below are incremental to those included in the 2001 annual consolidated financial statements.

(a) The accounting of the merger of EnerMark Income Fund ("EnerMark") and Enerplus Resources Fund ("Enerplus") which occurred on June 21, 2001 ("the Merger"), applied the reverse takeover form of the purchase method of accounting for business combinations. Accordingly, these consolidated financial statements of the Fund include the accounts of the merged Fund for the six months ended June 30, 2002 but the comparative figures for the prior year include the accounts of EnerMark as at and for the six months ended June 30, 2001, plus the results of Enerplus from June 21, 2001 to June 30, 2001.

All numbers of trust units and Warrants up to the June 21, 2001 Merger date have been restated using the merger exchange ratio of 0.173 EnerMark unit for each Enerplus unit (the "Merger Exchange Ratio").

(b) Effective for the fiscal years beginning on or after January 1, 2002, the Fund adopted the recommendations of the CICA on accounting for stock-based compensation which apply to new rights granted on or after that date. The Fund has elected to continue to measure compensation cost based on the intrinsic value of the award at the date of the grant and recognize that cost over the vesting period. As the exercise price of the rights granted approximates the market price of the trust units at the grant date, no compensation cost has been provided in the statement of income.

The exercise price of the rights granted under the Fund's rights plan may be reduced in future periods in accordance with the terms of the rights plan. The amount of the reduction cannot be reasonably determined as it is dependent upon a number of factors including, but not limited to, future prices received on the sale of oil and natural gas, future production of oil and natural gas, determination of the amounts to be withheld from future distributions to fund capital expenditures and the purchase and sale of property, plant and equipment. Therefore, it is not possible to determine a fair value for the rights granted under the plan.

2. FUND CAPITAL

(a) Unitholders' Capital

Authorized: Unlimited Number of Trust Units

Issued: (thousands)	June 30, 2002		December 31, 2001	
	Units	**Amount**	Units	Amount
Balance, beginning of period	**69,532**	**$ 1,826,507**	40,925	$ 1,050,986
Issued for cash:				
Pursuant to public offerings	**-**	**-**	4,313	101,039
Pursuant to Option Plans	**70**	**1,352**	135	2,530
Pursuant to exercise of warrants	**-**	**-**	1,197	33,319
Pursuant to expiry of warrants	**-**	**-**	-	2,846
Issued pursuant to the deemed acquisition of Enerplus (Note 1)	**-**	**-**	20,863	582,364
Issued pursuant to the management agreement (Note 3)	**-**	**-**	173	5,000
Distribution Reinvestment & Unit Purchase Plan	**220**	**5,344**	659	16,577
Issued for acquisition of property interests	**31**	**740**	1,267	31,846
Other	**-**	**(13)**	-	-
Balance, end of period	**69,853**	**$ 1,833,930**	69,532	$ 1,826,507

(b) Trust Unit Option Plan

As at June 30, 2002, 180,000 options issued pursuant to the Trust Unit Option Plan were outstanding representing 0.3% of the total units outstanding. Activity for the options issued pursuant to the option plan is summarized as follows:

(thousands except per unit amounts)	June 30, 2002		December 31, 2001	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Options outstanding at beginning of period	264	$ 20.93	27	$ 15.30
Exercised	(70)	$ 19.56	52	$ 17.10
Cancelled	(14)	$ 22.70	185	$ 22.90
Options outstanding at end of period	180	$ 21.41	264	$ 20.93
Options exercisable at end of period	119		99	

No new options have been granted under the Trust Unit Option Plan as this plan was superseded by the Trust Unit Rights Incentive Plan discussed below.

(c) Trust Unit Rights Incentive Plan

As at June 30, 2002, 1,359,000 rights issued pursuant to the Trust Unit Rights Incentive Plan were outstanding representing 1.9% of the units outstanding. Under the Incentive Plan, distributions per trust unit to Enerplus unitholders in a calendar quarter which represent a return of more than 2.5% of the net property, plant and equipment of Enerplus at the end of such calendar quarter would result in a reduction in the exercise price of the rights. During the three months ended June 30, 2002, the exercise price on 1,293,000 rights were reduced by $0.12 per right.

As it is not possible to determine the fair value of rights granted under the plan, compensation cost for pro forma disclosure purposes has been determined based on the excess of the unit price over the exercise price at the date of the financial statements. For the three and six months ended June 30, 2002, net income would be reduced by $9,000 and $19,000, for the estimated compensation cost associated with rights granted under the plan on or after January 1, 2002 with negligible impact on net income per trust unit during these periods.

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

(thousands except per unit amounts)	June 30, 2002		December 31, 2001	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Rights outstanding at beginning of period	1,318	$ 24.50	-	$ 24.50
Granted	81	$ 26.11	1,360	$ 24.50
Cancelled	(40)	$ 24.47	(42)	$ 24.50
Rights outstanding at end of period	1,359	$ 24.48	1,318	
Rights exercisable at end of period	-		-	

3. RELATED PARTY TRANSACTIONS

Management, advisory and administration services are supplied to the Fund on a fee and cost reimbursement basis, pursuant to an agreement with Enerplus Global Energy Management Company ("EGEM"). Management fees of $4,659,000 are reported on the Consolidated Statement of Income. As at June 30, 2002, $4,481,000 was payable to EGEM, pursuant to this agreement.

In addition, pursuant to a share purchase agreement related to the June 21, 2001 Merger, the Fund acquired shares of Enerplus Resources Corporation from EGEM for $2,545,000 payable over five years in quarterly instalments of $128,000 through a reduction of management fees. At June 30, 2002, the indebtedness remaining pursuant to this agreement was $2,162,000 of which $509,000 has been classified as current.

In addition to the transactions described above, Enerplus has entered into financial instrument contracts with an indirect subsidiary of El Paso Corporation, the ultimate parent of EGEM, as described in Note 5.

4. LONG-TERM DEBT

	June 30, 2002	December 31, 2001
Bank credit facilities	$ 172,481	$ 412,589
Senior unsecured notes	268,328	-
Total long-term debt	$ 440,809	$ 412,589

The senior unsecured notes (the "Notes") were issued on June 19, 2002 in the amount of US$175,000,000. They have a final maturity of June 19, 2014 and bear interest at 6.62% per annum, with interest paid semi-annually on June 19 and December 19 of each year. The Note Purchase Agreement requires the Fund to make five annual amortizing principal repayments of 20% of the initial principal amount, commencing on June 19, 2010.

Concurrent with the issuance of the Notes, the Fund entered into a cross currency swap, with a syndicate of major 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 banker's acceptances, plus 1.18%. Costs incurred in connection with issuing the Notes, in the amount of $1,992,000, are being amortized over the term of the Notes.

Proceeds from the Notes were fully applied to outstanding bank indebtedness and reduced the amount of credit available under the bank credit facilities (the "Facilities") from $620,000,000 to $351,672,000. The Facilities remain unsecured and consist of a $322,000,000 revolving committed line with an incremental two-year term, and a $29,672,000 demand operating line. Various borrowing options are available under the Facilities including prime rate based advances and banker's acceptance loans.

5. FINANCIAL INSTRUMENTS

The Fund uses various types of financial instruments to manage the risk related to fluctuating commodity prices. 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 these instruments as at June 30, 2002 with reference to forward prices and mark-to-market valuations provided by independent sources. The Fund may be exposed to losses in the event of default by the counterparties to these instruments. This credit risk is controlled by the Fund through the selection of financially sound counterparties.

Interest rate and cross currency swaps:

In addition to the cross currency swap described in Note 4, the Fund has entered into various interest rate swaps on a notional amount of bank debt, as follows:

Term	Notional Amount	Fixed Rate (1)
January 18, 2002 to January 18, 2005	$ 25 million	3.89%
June 3, 2002 to June 3, 2005	25 million	4.70%
June 4, 2002 to June 4, 2005	25 million	4.65%
	$ 75 million	

(1) Before banking fees that are expected to range between 0.85% and 1.05%.

The mark-to-market values of the $75 million interest rate swaps and the cross currency interest rate swap related to the Senior Unsecured Notes as at June 30, 2002 represent an unrealized loss of $299,000 and an unrealized gain of $106,000, respectively.

Crude Oil

Enerplus has entered into the following financial option transactions that are designed to reduce a downward impact of crude oil prices on 9,675 bbls/day of crude oil production for the remainder of 2002. The Fund also has contract positions of 6,500 bbls/day of crude oil for 2003 and 2,000 bbls/day of crude for 2004. The remaining costs to be amortized associated with these transactions was approximately $0.01 per trust unit or $430,000. The mark-to-market value of the financial crude oil hedges as at June 30, 2002 reflect an unrealized loss of $4,931,000.

TERM	Volume	WTI Crude Oil Price US$		
	bbls/day	Sold Call	Purchased Put	Sold Put
July 1, 2002 - Dec. 31, 2002 - 3-way	1,500	US$27.00	US$19.50	US$16.00
- 3-way (1)	1,500	US$25.00	US$19.50	US$17.00
- 3-way	2,175	US$27.00	US$19.50	US$17.00
- 3-way	1,500	US$28.00	US$20.10	US$17.00
- 3-way (2)	1,500	US$31.00	US$22.00	US$19.50
- 3-way (2)	1,500	US$30.00	US$24.00	US$21.35
Jan. 1, 2003 - Dec. 31, 2003 - 3-way	1,500	US$27.00	US$19.50	US$17.00
- 3-way	1,500	US$28.00	US$20.15	US$17.00
- 3-way (2)	1,500	US$28.51	US$22.00	US$19.50
Jan. 1, 2003 - Jun. 30, 2004 - 3-way (2)	1,500	US$28.00	US$22.50	US$19.60
- 3-way (2)	500	US$28.00	US$22.50	US$19.90

(1) *The counterparty to this 3-way crude oil option is a subsidiary of El Paso Corporation which is the ultimate parent of EGEM (refer to Note 3) and* the amount receivable/payable with respect to this transaction is currently not material. The remaining option premium for this instrument is $138,000 and is being amortized over the remaining term.

(2) Financial option transactions entered into during the second quarter of 2002.

Natural Gas

In addition to the crude oil price protection initiatives described above, Enerplus also has physical and financial contracts in place on approximately 76.9 MMcf/day of natural gas until October 31, 2002. The Fund also has varying contract and term positions with respect to 51.3 MMcf/day of natural gas for 2003 and 15.3 MMcf/day of natural gas for 2004. The remaining costs to be amortized associated with these transactions are $0.01 per trust unit or $1,017,000 in 2002 and $0.02 per trust unit or $1,694,000 in 2003. The mark-to-market value of the financial natural gas hedges as at June 30, 2002 reflects an unrealized loss of $7,025,000.

	MMcf/day	AECO $/Mcf CDN$				
	Daily volumes	Sold Call	Purchased Put	Sold Put	Fixed Price	Escalated Price
July 1, 2002 - Oct. 31, 2002						
Physical	3.8	-	-	-	$2.63	-
Physical	8.5	-	-	-	$3.97	-
Collar (1)	9.5	$5.27	$3.69	-	-	-
Put (1)	9.5	-	$3.69	-	-	-
3-way	9.5	$4.22	$3.29	$2.37	-	-
July 1, 2002 - Dec. 31, 2002						
Physical	2.8	-	-	-	$2.64	-
Physical	2.0	-	-	-	-	$2.01
Swap	3.8	-	$2.90	-	-	-
Collar	7.6	$4.22	$3.43	-	-	-
Collar	5.7	$4.81	$3.43	-	-	-
Collar	14.2	$4.22	$3.32	-	-	-
Continued on next page						

	MMcf/day	AECO $/Mcf CDN$				
	Daily volumes	Sold Call	Purchased Put	Sold Put	Fixed Price	Escalated Price
Nov. 1, 2002 - Dec. 31, 2002						
Collar [1]	7.1	$5.27	$3.69	-	-	-
Put [1]	7.1	-	$3.69	-	-	-
Call	9.5	$6.33	-	-	-	-
Jan. 1, 2003 - Mar. 31, 2003						
Call	9.5	$6.33	-	-	-	-
Jan. 1, 2003 - Oct. 31, 2003						
Physical	2.8	-	-	-	$2.64	-
Collar [1]	7.1	$5.27	$3.69	-	-	-
Put [1]	7.1	-	$3.69	-	-	-
Jan. 1, 2003 - Dec. 31, 2003						
Physical	2.0	-	-	-	-	$2.23
Swap	3.8	-	$2.90	-	-	-
3-way [2]	9.5	$7.91	$4.27	$3.17	-	-
3-way [2]	9.5	$7.39	$4.75	$3.17	-	-
Jan. 1, 2004 - Oct. 31, 2004						
Swap	3.8	-	$2.90	-	-	-
Jan. 1, 2004 - June 30, 2004						
3-way [2]	9.5	7.39	$4.75	$3.17	-	-
2004 - 2010						
Physical	2.0		-	-	-	$2.33

[1] The counterparty to these natural gas collars and puts is a subsidiary of El Paso Corporation which is the ultimate parent of EGEM (refer to Note 3) and the amounts receivable/payable with respect to these transactions are currently not material. The option premiums for these instruments are $2,711,000 and are being amortized over their remaining terms.

[2] Additional transactions entered into during the second quarter of 2002.

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(2) Environment, Safety & Reserves Committee
(3) Corporate Governance Committee
(4) Compensation & Human Resources Committee
(5) *Chairman of the Board*
(6) Chairman of the Audit & Risk Management Committee
(7) Chairman of the Environment, Safety & Reserves Committee
(8) Chairman of the Corporate Governance Committee
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ABBREVIATIONS

AECO	Alberta Energy Company interconnect with the Nova Gas System
ARTC	Alberta Royalty Tax Credit
bbl(s)/day	barrel(s) per day
BOE(s)/day	barrel of oil equivalent per day (6 Mcf gas = 1 bbl crude oil)
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
MMcf/day	million cubic feet per day
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
W.I.	percentage working interest of ownership
WTI	West Texas Intermediate oil at Cushing, Oklahoma