ENERPLUS RESOURCES FUND
Form SUPPL
November 26, 2002

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FILED PURSUANT TO GENERAL INSTRUCTION II.L. OF FORM F-10; FILE NO. 333-101240

PROSPECTUS

7,000,000 Trust Units

US$16.54 per Trust Unit

We are selling 7,000,000 trust units. We have granted the underwriters an option to purchase up to 1,050,000 additional trust units solely to cover over-allotments.

Our trust units are listed on the New York Stock Exchange under the symbol "ERF" and on the Toronto Stock Exchange under the symbol "ERF.UN." The last reported sale price of our trust units on the New York Stock Exchange on November 25, 2002 was US$16.54 per trust unit and the last reported sale price of our trust units on the Toronto Stock Exchange on November 25, 2002 was Cdn$25.99 per trust unit.

Investing in our trust units involves risks. See "Risk Factors" beginning on page 17.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

We are permitted to prepare this prospectus in accordance with Canadian disclosure requirements, which are different from those of the United States. We prepare our financial statements in accordance with Canadian generally accepted accounting principles, and they are subject to Canadian auditing and auditor independence standards. They may not be comparable to financial statements of United States companies.

Owning the trust units may subject you to tax consequences both in the United States and Canada. This prospectus may not describe these tax consequences fully. You should read the tax discussion under "Certain Income Tax Considerations."

Your ability to enforce civil liabilities under the United States federal securities laws may be affected adversely because we are organized in Canada, some of our officers and directors and some of the experts named in this prospectus are Canadian residents, and substantially all of our assets and the assets of those officers, directors and experts are located outside of the United States.

	Per Trust Unit		Total	
Public Offering Price	US$	16.540	US$	115,780,000
Underwriting Discount	US$	0.827	US$	5,789,000
Proceeds to Enerplus Resources Fund, before expenses	US$	15.713	US$	109,991,000

The underwriters expect to deliver the trust units to purchasers on or about November 29, 2002.

Joint Book-Running Managers

Salomon Smith Barney **CIBC World Markets**

RBC Capital Markets

BMO Nesbitt Burns

Lehman Brothers

Scotia Capital

UBS Warburg

Putnam Lovell NBF

TD Securities

Canaccord Capital USA

Raymond James

November 25, 2002

You should rely only on the information contained or incorporated by reference in this prospectus. We have not authorized anyone to provide you with different information. We are not making an offer to sell these securities in any jurisdiction where the offer is not permitted. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the front of this prospectus.

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EXCHANGE RATES

We present our financial information in Canadian dollars. In this prospectus, except where we indicate otherwise, all dollar amounts are in Canadian dollars. References to "$" or "Cdn$" are to Canadian dollars and references to "US$" are to United States dollars. The following table sets forth certain exchange rates based upon the noon buying rate in New York City for cable transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York. These rates are set forth as United States dollars per Cdn$1.00 and are the inverse of the noon buying rate. The average is derived by taking an average of the exchange rates on the last business day of each month during the applicable period. On November 25, 2002, the inverse of the noon buying rate was US$0.6355 per Cdn$1.00.

	Year Ended December 31,				Nine Months Ended September 30,	
	1998	1999	2000	2001	2001	2002
High	0.7105	0.6925	0.6969	0.6697	0.6697	0.6619
Low	0.6341	0.6535	0.6410	0.6241	0.6330	0.6200
Period end	0.6504	0.6925	0.6669	0.6279	0.6330	0.6304

	Year Ended December 31,				Nine Months Ended September 30,	
Average	0.6722	0.6746	0.6727	0.6446	0.6491	0.6369

PRESENTATION OF OUR FINANCIAL AND OPERATIONAL INFORMATION

The financial statements included and incorporated by reference in this prospectus have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). Canadian GAAP differs in some significant respects from U.S. GAAP and thus our financial statements may not be comparable to the financial statements of U.S. companies. The principal differences as they apply to us are summarized in the notes to the financial statements included or incorporated by reference in this prospectus.

The merger of Enerplus Resources Fund and EnerMark Income Fund, which occurred on June 21, 2001, was accounted for as a reverse take-over because the former unitholders of EnerMark Income Fund owned the majority of the outstanding trust units of the consolidated Fund after the merger. Under this form of purchase accounting, according to both Canadian and U.S. GAAP, EnerMark Income Fund is deemed to have acquired Enerplus Resources Fund. The consolidated financial statements of the Fund for the year ended December 31, 2001 therefore include only EnerMark Income Fund's operating and financial results prior to the merger and the results of the merged Fund thereafter. Unless otherwise indicated, all comparative figures and references to prior years are those of EnerMark Income Fund. Accordingly, unless otherwise indicated, all references to "our" or "Enerplus' " financial statements or information for periods prior to June 21, 2001 are to those of EnerMark Income Fund, including the consolidated financial statements of the Fund for the years ended December 31, 2000 and 1999 included and incorporated by reference in this prospectus. The financial statements of Enerplus Resources Fund as it existed prior to the merger (referred to in this prospectus as "pre-merger Enerplus") are incorporated by reference in this prospectus. Except for trust unit information contained in "Summary", "Price Range and Trading Volumes of Trust Units" and "Distributions", all disclosures of trust units and per trust unit data up to the June 21, 2001 merger date have been restated using the merger exchange ratio of 0.173 of a trust unit of pre-merger Enerplus for each trust unit of EnerMark Income Fund.

Additionally, unless otherwise indicated, all historical production, reserve and other operational information is based on the historical operations of EnerMark Income Fund only. Unless otherwise indicated, the production, reserve and other operational information attributable to the operations of pre-merger Enerplus is not included; however, this information is included for the merged Fund since June 21, 2001.

Unless otherwise indicated, pro forma financial information included in this prospectus gives pro forma effect to the merger of Enerplus Resources Fund with EnerMark Income Fund completed on June 21, 2001 and other transactions and adjustments as if the merger had occurred on January 1, 2001, as described in the notes to the pro forma financial statements beginning on page F-49.

We have adopted the standard of 6 Mcf:1 barrel of oil equivalent when converting natural gas to barrels of oil equivalent, or Boe.

PRESENTATION OF OUR RESERVE INFORMATION

The United States Securities and Exchange Commission generally permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves net of royalties and interests of others that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. Canadian securities laws permit oil and gas companies, in their filings with Canadian securities regulators, to disclose not only proved reserves but also probable reserves, and to disclose reserves and production on a gross basis before deducting royalties. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. Because we are permitted to prepare this prospectus in accordance with Canadian disclosure requirements, we have disclosed in this prospectus and in the documents incorporated by reference reserves designated as "probable" and "established." The SEC's guidelines strictly prohibit reserves in these categories from being included in filings with the SEC that are required to be prepared in accordance with U.S. disclosure requirements. Moreover, we have determined and disclosed estimated future net cash flow from our reserves using both constant and escalated prices and costs, whereas the SEC generally requires that prices and costs be held constant at levels in effect at the date of the reserve report.

Reserve estimates of Enerplus contained in, and incorporated by reference into, this prospectus are based upon reports prepared by Sproule Associates Limited, a large, established Canadian independent firm of petroleum engineers, with respect to our reserves as of January 1, 2002. Sproule evaluated properties which comprised approximately 86% of our gross proved developed producing reserve value and 83% of our gross proved plus probable reserve value, in both cases discounted at 12%. We have evaluated the balance of the properties internally using evaluation parameters consistent with those used by Sproule. Reserve estimates of recently acquired Celsius Energy Resources Ltd. contained in this prospectus are based upon two separate reports prepared by Sproule and by Gilbert Laustsen Jung Associates Ltd., or GLJ, as of January 1, 2002. Together, Sproule and GLJ evaluated 100% of Celsius' reserves.

Although the definitions of proved reserves under SEC Regulation S-X and Canadian National Policy 2-B are different, in the opinion of Sproule Associates Limited, estimates of our net proved reserves using constant price and cost assumptions in this prospectus are, in all material respects, equivalent to those which would be determined under SEC Regulation S-X. This prospectus has not been, and will not be, reviewed by the SEC.

In this prospectus, all estimates of reserves and production are before deduction of royalties, unless otherwise indicated. All future cash flows have been stated prior to any provision for income taxes, interest, general and administrative costs and management fees and indirect costs and after deduction of royalties and estimated future capital expenditures. The estimated present worth values of future net cash flow contained in this prospectus are not representative of the fair market value of the reserves. Our actual reserves will be greater than or less than the estimates provided herein.

Outlined below are certain important terms that are used in the description of our reserves. Please also read "Glossary of Terms" for additional terms used to describe our reserves.

gross. When used to describe our share of reserves means the total of our working interests before deducting royalties payable to third parties.

net. When used to describe our share of reserves means the total of our working interests after deducting royalties payable to third parties.

proved reserves. Those quantities of oil, natural gas and natural gas by-products which, upon analysis of geologic and engineering data, appear with a high degree of certainty to be recoverable at commercial rates in the future from known oil and natural gas reservoirs under current economic and operating conditions for reserves based on constant price and cost assumptions, and presently anticipated economic and operating conditions for the reserves based on escalated price and cost assumptions.

probable reserves. Those reserves which may be recoverable as a result of the beneficial effects which may be derived from the future institution of some form of pressure maintenance or other secondary recovery method, or as a result of a more favourable performance of the existing recovery mechanism than that which would be deemed proved at the present time, or those reserves which may reasonably be assumed to exist because of geophysical or geological indications and drilling done in regions which contain proved reserves. Probable reserves are presented before deduction of royalties and are based on escalated price and cost assumptions, unless otherwise indicated.

established reserves. Proved reserves plus 50% of probable reserves, before the deduction of royalties and based on escalated price and cost assumptions, unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this prospectus, and in certain documents incorporated by reference into this prospectus, constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Act of 1934, as amended, which are made pursuant to the safe harbor provisions of the United States Private Securities Litigation Reform Act of 1995. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "plans", "should", "believe" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in our forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable. However, we cannot assure you that these expectations will prove to be correct. You should not unduly rely on forward-looking statements included in, or incorporated by reference into, this prospectus. These statements speak only as of the date of this prospectus or as of the date specified in the documents incorporated by reference into this prospectus, as the case may be.

In particular, this prospectus, and the documents incorporated by reference in this prospectus, contain forward-looking statements pertaining to the following:

- the size of our reserves;

- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to our reserves through acquisitions;
- expectations regarding the ability to maintain or increase our production through exploitation and development of our reserves;
- treatment under governmental regulatory regimes;
- timing and amount of future production;
- prices for oil and natural gas produced;
- operating and other costs;
- business strategies and plans;
- capital expenditure programs; and
- projections of distributions on our trust units.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this prospectus:

- volatility in market prices for oil, NGLs and natural gas;
- liabilities inherent in our oil and gas operations;
- uncertainties associated with estimating and producing reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems; and
- the other factors discussed under "Risk Factors."

These factors should not be construed as exhaustive. We undertake no obligation to publicly update or revise any forward-looking statements.

SUMMARY

This summary highlights selected information contained in greater detail elsewhere in this prospectus. This summary does not contain all of the information that you should consider before investing in our trust units. You should carefully read the entire prospectus and the documents incorporated by reference herein, including the section entitled "Risk Factors" and the financial statements included or incorporated by reference herein, before making an investment decision.

Some of the terms used in this prospectus and the documents incorporated by reference are defined in "Glossary of Terms." All references to "Enerplus", "we", "us" and "our" refer to Enerplus Resources Fund, EnerMark Inc. and Enerplus Resources Corporation and their subsidiaries on a collective basis. All references to the "Fund" refer to Enerplus Resources Fund only. All references to "EnerMark" refer to EnerMark Inc. and its subsidiaries, and all references to "ERC" refer to Enerplus Resources Corporation and its subsidiaries. EnerMark and ERC are collectively referred to as the "Operating Companies." All references to "EGEM" or the "Manager" refer to Enerplus Global Energy Management Company. References to "$" or "Cdn$" are to Canadian dollars and references to "US$" are to United States dollars.

Enerplus

Who We Are

We are the largest conventional oil and gas trust in North America in terms of market capitalization, production volumes and oil and natural gas reserves. Our trust units are listed on the Toronto Stock Exchange and the New York Stock Exchange and our market capitalization as at November 25, 2002 was approximately $1.9 billion. Through our operating subsidiaries, we actively manage the acquisition and development of, and production from, oil and natural gas properties. Our operations are currently focused exclusively in western Canada.

We hold interests in a diversified and balanced portfolio of mature oil and natural gas properties. Our properties generally have predictable production profiles, long reserve lives and the opportunity for development. Approximately 55% of our production and reserves is comprised of natural gas and approximately 45% is comprised of crude oil and natural gas liquids, or NGLs. As of January 1, 2002, we had established reserves of 312 MMBoe and net proved reserves of 215 MMBoe. The established reserve life index and the R/P ratio of our properties as of January 1, 2002 was 14.0 years and 9.4 years, respectively.

Our primary purpose is to generate and distribute cash flows to unitholders. As such, we focus on the acquisition and lower-risk development of mature, long-life oil and natural gas properties. We do not participate in exploration activity because of the higher risks involved. Our production is typically more predictable and stable than traditional exploration and production, or E&P, companies and our operations are generally not as capital intensive.

We make monthly cash distributions to our unitholders from the net cash flows that we receive from our oil and gas operations. The amount of that net cash flow is subject to many factors, including fluctuations in the quantity of oil and natural gas that we produce, the prices we receive for that production and the operating costs associated with that production. Our cash distribution for November 2002 was $0.30 (US$0.19) per trust unit, and we have paid cumulative distributions of $3.40 (US$2.16) per trust unit in the twelve months through and including October 2002.

Since its inception, Enerplus Resources Fund has grown significantly through a series of mergers and acquisitions, the most significant of which was the merger of Enerplus Resources Fund and EnerMark Income Fund on June 21, 2001. During that time, Enerplus, meaning Enerplus Resources Fund as it existed prior to the merger with EnerMark Income Fund on June 21, 2001 (referred to as "pre-merger Enerplus") and the merged Fund after that date, has increased its average daily production volumes from 34 Boe/day for the twelve months ended November 30, 1986 to 61,493 Boe/day for the nine months ended September 30, 2002.

For Canadian income tax purposes, we are classified as a "mutual fund trust." For United States federal income tax purposes, we are considered a corporation and are not a partnership or a master limited partnership (or MLP). You should read the information in "Certain Income

Tax Considerations" and consult your own tax advisors to find out more about the tax consequences of owning trust units.

Our Business Strategy

Our objective is to maximize our net cash flows, and therefore the distributions to our unitholders, while minimizing the risk associated with these cash flows, optimizing the economic recovery from our properties and assets and maintaining a prudent capital structure. To accomplish these goals, our business strategy is to:

continue to develop our existing properties to maintain and enhance oil and natural gas production;

acquire suitable energy-related properties and assets such as mature, long-life oil and natural gas properties with predictable production profiles;

maintain a balanced portfolio of geographically and geologically diversified oil and natural gas properties;

control costs through the efficient operation of existing and acquired properties;

manage commodity price risk, when appropriate, through hedging agreements; and

employ financial and corporate policies that facilitate access to capital.

History of Distributions and Unit Price

The following charts present historical distribution and trust unit price information for a specified period. Other periods will have different results and those differences may be significant. These charts are for illustrative purposes only and are not intended to be indicative of future distributions or trust unit prices.

You should consider the following notes when reading these charts, as well as the notes following each chart:

(1) Historical distributions for the periods prior to June 2001 represent only the distributions paid by pre-merger Enerplus. They do not represent the historical distributions paid by EnerMark Income Fund prior to its merger with Enerplus Resources Fund on June 21, 2001. Please read "Presentation of Our Financial and Operational Information." Certain information with respect to the historical distributions paid by EnerMark Income Fund can be found under "Distributions."

(2) Distributions presented in the chart are calculated on a calendar basis. Distribution and trust unit price information give effect to the one for six consolidation of the trust units of pre-merger Enerplus which became effective on June 8, 2000.

(3) Distributions paid do not include cash flow retained by Enerplus for debt reduction. See "Distributions Distributions Policy."

Since January 1, 1992, Enerplus Resources Fund has made cumulative cash distributions of $38.19 per trust unit, including the distribution of $0.30 per trust unit paid in October 2002. The closing price of our trust units on the Toronto Stock Exchange on October 31, 2002 was $28.01 per trust unit compared to a closing price of $14.10 per trust unit on the Toronto Stock Exchange on December 31, 1991. In connection with the chart below, please read the notes on page 2 of this prospectus.

Cumulative Cash Distributions per Trust Unit
January 1, 1992 to October 31, 2002(1)

Since 1992, the annual cash distributions per trust unit paid by Enerplus Resources Fund have ranged from $2.46 to $5.95 and have tended to fluctuate with commodity prices. In connection with the chart below, please read the notes on page 2 of this prospectus.

Cash Distributions per Trust Unit and Benchmark Crude Oil Prices
January 1992 to Ten Months Ended October 2002[(1)]

Our trust units are listed on the Toronto Stock Exchange under the symbol "ERF.UN" and have been listed on the New York Stock Exchange under the symbol "ERF" since November 17, 2000. In connection with the charts below, please read the notes on page 2 of this prospectus, as well as the notes following each of the charts.

Total Pre-Tax Return Performance of Enerplus,
the S&P/TSX Composite Index and the TSX Oil & Gas Producers Index
November 1, 1992 to October 31, 2002(1)(2)(3)(4)

(4) Assumes the reinvestment of gross distributions and/or dividends without deduction for the payment of (i) applicable taxes on those distributions and/or dividends or (ii) applicable transaction costs incurred in the reinvestment, and therefore is not illustrative of returns achieved by most investors.

(5) Based on the weekly closing price of Enerplus trust units on the Toronto Stock Exchange.

Total Pre-Tax Return Performance of Enerplus,
the S&P 500 Index and the S&P 500 Energy Index
November 1, 1992 to October 31, 2002(1)(2)(3)(6)

(6) Assumes the reinvestment of gross distributions and/or dividends without deduction for the payment of (i) applicable taxes on those distributions and/or dividends or (ii) applicable transaction costs incurred in the reinvestment, and therefore is not illustrative of returns achieved by most investors.

(7) Based on the weekly closing price of Enerplus trust units on the Toronto Stock Exchange in Canadian dollars, converted to United States dollars at the Bank of Canada exchange rate on such date.

Our Organizational Structure

Our trust structure provides us with an efficient means to distribute our net cash flows to our unitholders. Our structure increases the amount of cash distributions available to our unitholders as cash flows have historically flowed from the Operating Companies to the Fund with little or no corporate income tax payable at the Operating Company level. As the Fund distributes all of its taxable income to its unitholders, no income taxes are paid at the Fund level.

The following diagram represents a summary of our current structure and the flow of funds from the oil and natural gas properties owned by the Operating Companies to the Fund, as well as the cash distributions to our unitholders.

The Fund's primary sources of net cash flow are (1) payments received from 95% and 99% net royalty interests granted to the Fund by EnerMark and ERC, respectively, on the production from their oil and natural gas properties, (2) interest and principal payments on debt issued to the Fund by EnerMark, and (3) dividend payments received by the Fund from EnerMark and, indirectly, from ERC.

Enerplus Resources Fund

Enerplus Resources Fund is a publicly traded open-ended investment trust whose principal undertaking is to issue trust units to the public and to indirectly invest its funds in oil and natural gas properties and other energy-related assets. The Fund's investment in these oil and natural gas interests is held entirely through its Operating Companies. Each trust unit represents an equal, undivided beneficial interest in the Fund. The Fund pays cash distributions to its unitholders from the net cash flow received from the Operating Companies. The Fund is managed by EGEM pursuant to a management agreement. The Fund is governed by the laws of the Province of Alberta. Its head and principal office is located at The Dome Tower, Suite 3000, 333 - 7th Avenue S.W., Calgary, Alberta, Canada T2P 2Z1.

EnerMark Inc. and Enerplus Resources Corporation

EnerMark and ERC own and operate our oil and gas properties on behalf of the Fund. Both EnerMark and ERC are corporations organized under the *Business Corporations Act* (Alberta). All of the issued and outstanding shares of EnerMark are owned by the Fund, and all of the issued and outstanding shares of ERC are owned by EnerMark. EnerMark and ERC are managed by EGEM pursuant to a management agreement.

Enerplus Global Energy Management Company

EGEM manages the Fund and the Operating Companies pursuant to a management agreement. EGEM is a corporation organized under the *Companies Act* (Nova Scotia) and is an indirect wholly-owned subsidiary of El Paso Corporation of Houston, Texas. The board of directors of EnerMark, which oversees the business and affairs of Enerplus, has retained EGEM to provide comprehensive management services and to administer and regulate the day-to-day operations and make executive decisions in respect of Enerplus that conform to general policies and principles established by the board of directors of EnerMark. For these services, EGEM receives a management fee, incentive fees based on the performance of the Fund and reimbursement of its general and administrative expenses. Please read "Management and Corporate Governance."

Governance of Enerplus

EnerMark's board of directors is responsible for the overall governance of Enerplus and establishes the general policies and principles outlining the overall management and direction of Enerplus, including the supervision of EGEM. The board of directors must be comprised of a minimum of seven directors, three of which are nominated by EGEM pursuant to the governance agreement. The remainder of the board is nominated by the unitholders. Currently there are eight directors of EnerMark, a majority of which are independent, including the Chairman of the board of directors. The board of directors is responsible for the annual renewal, for continuous three year terms, of the management agreement pursuant to which EGEM is engaged, with the current term expiring on June 30, 2005. For further details, please read "Management and Corporate Governance."

Our Properties

Substantially all of our oil and natural gas properties are located in western Canada in the provinces of Alberta, British Columbia and Saskatchewan. As of January 1, 2002, we had established reserves of 132 MMBbls of crude oil and NGLs and 1,082 Bcf of natural gas, for a total of 312 MMBoe, and net proved reserves of 91 MMBbls of crude oil and NGLs and 745 Bcf of natural gas, for a total of 215 MMBoe. For the nine month period ended September 30, 2002, our properties produced, on a barrel of oil equivalent basis, approximately 55% natural gas, 38% crude oil and 7% NGLs. The gross average daily production from our properties for the nine months ended September 30, 2002 was 204,463 Mcf/day of natural gas and 27,416 Bbls/day of crude oil and NGLs, for a total of 61,493 Boe/day.

For a description of the general characteristics of the principal regions in which our properties are located, please read "Business Our Properties."

The following table shows our principal properties by region, together with the gross average daily production for the nine months ended September 30, 2002 attributable to our interests in each property.

	Gross Average Daily Production for the Nine Months Ended September 30, 2002
	Total

	Gross Average Daily Production for the Nine Months Ended September 30, 2002			
	Oil and NGLs	Natural Gas		% of Total Production
	(Bbls/day)	(Mcf/day)	(Boe/day)	(%)
Principal Properties:				
North West Region				
Deep Basin	631	11,219	2,501	4.1%
Valhalla	762	8,610	2,197	3.6
Progress	759	5,527	1,680	2.7
Cranberry	68	3,060	578	0.9
Central Region				
Joarcam	2,194	5,743	3,151	5.1
Pembina 5 Way/South Buck Lake	2,395	1,592	2,660	4.3
Kaybob	344	4,953	1,170	1.9
Pine Creek	224	4,522	978	1.6
Willesden Green	208	2,748	666	1.1
East Central Region				
Giltedge	1,635	416	1,704	2.8
Gleneath	1,038	390	1,103	1.8
Auburndale	559	573	655	1.1
Hayter	676	14	678	1.1
Kessler	576	101	593	1.0
Cadogan	442		442	0.7
David	372	58	382	0.6
South Central Region				
Hanna/Garden Plains	2	12,500	2,085	3.4
Benjamin	13	12,425	2,084	3.4
Sylvan Lake	689	3,556	1,282	2.1
Ferrier	240	4,738	1,030	1.7
Bashaw	16	3,491	598	1.0
Harmattan	221	1,257	431	0.7
South East Region				
Medicine Hat Region	7	35,690	5,955	9.7
Medicine Hat Glauconite "C"	1,152	1,248	1,360	2.2
Jenner	394	1,883	708	1.2
Other	11,799	78,149	24,822	40.2
Total	27,416	204,463	61,493	100.0%

We actively manage our portfolio of oil and natural gas properties through our acquisition, divestiture and development activities. Our properties generally have the following characteristics:

Long-life properties with predictable production profiles. The majority of our properties have predictable production profiles and are relatively long-life properties. This facilitates our ability to generate relatively stable and predictable production from our properties. As of January 1, 2002, the established reserve life index and R/P ratio of our properties was 14.0 years and 9.4 years, respectively.

Diversified and balanced portfolio of assets with focus on core areas. Our portfolio of properties is both diversified, from a geographical and geological perspective, and well balanced between liquids and natural gas. Our properties are located throughout the Western Canadian Sedimentary Basin and access both shallow and deep producing horizons. For the nine months ended September 30, 2002, production from our properties was approximately 55% natural gas and 45% crude oil and NGLs, on a Boe basis. We are not dependent on any single property for a significant portion of our production as no single property currently represents more than 10% of our total production. Notwithstanding this diversity, our top 25 principal properties currently represent approximately 60% of our total production. Our focus on these core areas increases the efficiency of our operations and generally allows us to reduce operating costs, develop a strong understanding of the characteristics of these properties and continue to expand in these areas as we identify favourable opportunities.

Substantial development opportunities. We have identified development opportunities to mitigate declines in production, upgrade our reserves and extend the useful lives of many of our properties. We believe that these opportunities will allow us to add to our production at costs that are typically lower than through acquisitions. Our development activities have historically been relatively low-risk. In 2001, we participated in the drilling of 321.6 net development wells with a 99% success rate. For the nine months ended September 30, 2002, we participated in the drilling of 181.0 net development wells with a 99% success rate.

High level of operatorship. As at September 30, 2002, we operated properties comprising approximately 65% of our production. By operating our properties we are better able to control both the operating costs and the optimization of recovery from our reserves.

Acquisition and Development Activities

Since we do not engage in exploration activities, we rely primarily upon acquisitions to both replenish and add to our oil and natural gas reserves. In pursuing acquisitions, we employ a focused and disciplined strategy to ensure that the reserves being considered are a strategic fit with our existing portfolio of properties. We have typically funded our acquisitions through either borrowings from our existing credit facility or the direct issuance of trust units. Borrowings are subsequently repaid through the issuance of additional trust units or from internally generated cash flows. This strategy provides us with the flexibility to respond to acquisition opportunities.

A common strategy of E&P companies is to divest mature properties in order to redeploy capital into higher-risk exploration. Because of our focus on exploiting mature properties, we provide them with a ready, accessible market for those divestitures. To the extent that our acquisitions include undeveloped properties, we enter into farmout or swap agreements under which an E&P company will explore and drill the undeveloped properties on our behalf, generally at no cost to us, in exchange for a portion of our interests in the property. Additionally, our size facilitates our ability to make relatively large acquisitions as compared to many of our competitors. Finally, the tax effectiveness of our trust structure allows us to bid competitively for oil and natural gas properties against less tax-efficient entities.

We undertake lower-risk development activities to mitigate declines in total production, upgrade our reserves and extend the useful lives of many of our properties. Development activities are particularly important to us during periods when there are a limited number of attractive acquisition opportunities. Our development activities provide a lower-risk, less capital intensive alternative for increasing production volumes than do traditional exploration activities. Our development activities are typically funded through debt which is subsequently repaid through issuances of trust units and internally-generated cash flow.

Recent Developments

Potential Acquisitions

We continue to evaluate potential acquisitions of oil and natural gas properties, companies and trusts and other energy-related assets as part of our ongoing acquisition program. We are currently in negotiations regarding several potential acquisitions which together could have purchase prices aggregating approximately $200 million. As of the date of this prospectus, we have not reached agreement with the potential sellers on the price or terms of any of the potential acquisitions. Accordingly, we cannot predict whether any of these current opportunities will result in one or more acquisitions for the Fund.

Acquisition of Celsius Energy Resources Ltd.

On October 21, 2002, we acquired all of the outstanding shares and retired the debt of Celsius Energy Resources Ltd., a private oil and natural gas producer based in Calgary, Alberta which was a wholly owned Canadian subsidiary of U.S.-based Questar Market Resources Inc., for total cash consideration of $165.9 million, after working capital adjustments. On October 22, 2002, Celsius was amalgamated with EnerMark.

The Celsius properties are primarily located in Alberta and northeastern British Columbia. Many of the Celsius properties are located in areas in which we were active prior to the acquisition, including the Verger, Countess, Pine Creek and Deep Basin areas. The gross average daily production from the Celsius properties for September 2002 was approximately 5,750 Boe/day consisting of a 22,476 Mcf/day of natural gas, 1,724 Bbls/day of crude oil and 280 Bbls/day of NGLs. We estimate that the Celsius properties contained 18 MMBoe of established reserves as of July 31, 2002, resulting in an acquisition cost of $27,826 per daily producing Boe and $8.89 per Boe of established reserves. The Celsius properties have operating characteristics that are generally consistent with our existing properties. Included in the acquisition are approximately 103,000 net acres of undeveloped land that will provide further development opportunities to us through potential farmout and swap agreements.

Please read "Appendix B Information Regarding Celsius Energy Resources Ltd.," which contains additional information regarding the operations and reserves of Celsius, including a description of certain assumptions made in preparing the reserve evaluations of Celsius.

Issuance of Trust Units

On September 12, 2002, we completed an offering of 4,750,000 trust units for gross proceeds of $127,538,000. The offering was conducted exclusively in Canada, and the net proceeds of $120,886,000 were used to reduce debt incurred with respect to acquisitions, capital expenditures and general corporate expenditures.

Issuance of Senior Unsecured Notes

On June 19, 2002, EnerMark completed the private placement of US$175 million of senior unsecured notes to a group of United States institutional investors. The notes have a coupon rate of 6.62% based on the par price and have a twelve year term with a ten year average life, as 20% of the principal repayment is required on June 19, 2010 and annually thereafter, until June 19, 2014. The net proceeds were used to repay bank indebtedness, which reduced the amount of credit available under EnerMark's bank facilities.

The Offering

Trust units offered by Enerplus Resources Fund	7,000,000 trust units
Trust units to be outstanding after the offering	81,811,975 trust units
Over-allotment option	1,050,000 trust units
New York Stock Exchange symbol	ERF
Toronto Stock Exchange symbol	ERF.UN
Use of proceeds	We will use the net proceeds from this offering to reduce outstanding borrowings under our credit facilities. These outstanding borrowings were incurred in connection with our acquisition of Celsius and our ongoing acquisition and development activities. Our credit facility may thereafter be drawn upon from time to time to finance acquisitions (including those described under "Recent

	Developments Potential Acquisitions"), development projects or for general working capital purposes. Please read "Use of Proceeds."
Risk factors	An investment in our trust units involves risks. See "Risk Factors" beginning on page 17 of this prospectus.
Timing of next distribution	Cash distributions by the Fund are generally payable on the twentieth day of each month to unitholders of record on the tenth day or the immediately preceding business day of such month. A distribution of $0.30 (US$0.19) per trust unit was paid in November 2002. Purchasers in this offering will be eligible to receive the distribution for December 2002 on December 20, 2002 (so long as the purchaser is a unitholder of record on December 10, 2002). Cash distributions payable to United States holders are payable on the same date and are converted into U.S. dollars. Please read "Distributions" for further details and "Certain Income Tax Considerations Canadian Federal Income Tax Considerations Taxation of Unitholders Not Resident in Canada" for a discussion of the Canadian withholding tax applicable to United States holders.
U.S. tax considerations	We are a corporation, and not a partnership, for United States federal income tax purposes. The ownership or sale of trust units by a regulated investment company or mutual fund will generate qualifying income to it, and a trust unit will be treated as a qualifying asset. Please read "Certain Income Tax Considerations United States Federal Income Tax Considerations for United States Holders."

The number of trust units to be outstanding after the offering is based on 74,811,975 trust units outstanding as of October 31, 2002 and assumes no exercise of the underwriters' over-allotment option. It does not include 1,483,633 trust units that may be issued upon exercise of options and rights outstanding as of October 31, 2002 under our trust unit option or rights incentive plans.

Unless otherwise indicated, the information presented in this prospectus assumes the underwriters' over-allotment option is not exercised.

Summary Operating Information

The following table contains a summary of certain of our operating information for the periods indicated. The operating information for 1999, 2000 and up to June 21, 2001 contained in the following table is only that of EnerMark Income Fund. Information attributable to the operations of pre-merger Enerplus is not included. Operating information of the merged Fund is included in the 2001 information from June 21, 2001 forward. Please read "Presentation of Our Financial and Operational Information."

	Year Ended December 31,			Nine Months Ended September 30,
	1999	**2000**	**2001**	**2002**
Gross Daily Average Production:				
Oil and natural gas liquids (Bbls/day)	13,396	14,200	24,570	27,416
Natural gas (Mcf/day)	71,713	101,473	176,671	204,463
Total (Boe/day)	25,348	31,112	54,015	61,493
Average Realized Price:(1)				
Oil ($ per Bbl)	$ 23.26	$ 33.67	$ 31.21	$ 33.30
Natural gas ($ per Mcf)	2.33	4.53	5.60	3.43
Natural gas liquids ($ per Bbl)	16.14	32.33	31.12	23.06
Combined ($ per Boe)	18.32	30.14	32.43	25.52
Crown, freehold and other royalties ($ per Boe)	$ 3.47	$ 7.10	$ 6.73	$ 5.27
Operating costs ($ per Boe)	$ 4.02	$ 4.83	$ 6.09	$ 5.71

(1) Average realized prices are inclusive of hedging activity. Please read "Business Risk Management."

Summary Reserve Information

The following tables show selected oil and natural gas reserve data for Enerplus. The following information has been derived from the report prepared by Sproule Associates Limited with respect to our reserves as of January 1, 2002, which was the effective date of our last independent reserves evaluation. Sproule is a large, established Canadian independent firm of petroleum engineers. These tables should be read together with the information under "Appendix A Enerplus Reserves Information" and, in particular, the notes following the reserves tables contained in Appendix A, which include a description of certain assumptions made in preparing our reserve evaluations. Certain columns may not add due to rounding. For a description of certain terms used below and certain differences between estimating reserves under Canadian and U.S. reserve disclosure guidelines, please read "Presentation of Our Reserve Information" and "Glossary of Terms."

Reserves as of January 1, 2002
Canadian Presentation
(Gross Reserves Using Escalated Prices and Costs)

					Estimated Future Net Cash Flow(1)	
	Crude Oil	**Natural Gas Liquids**	**Natural Gas**	**Total**	**Undiscounted**	**Discounted at 10%**
	(MBbls)	**(MBbls)**	**(MMcf)**	**(MBoe)**	**(in thousands)**	
Proved reserves:						
Developed producing	86,770	13,685	722,692	220,904	$ 2,992,588	$ 1,376,940
Developed non-producing	620	512	58,791	10,930	157,757	78,807
Undeveloped	7,457	1,917	169,650	37,649	401,713	170,532
Total proved reserves	94,847	16,114	951,133	269,483	3,552,058	1,626,279
Probable reserves (risked at 50%)	18,821	2,337	130,345	42,882	644,955	159,099
Established reserves	113,668	18,451	1,081,478	312,365	$ 4,197,013	$ 1,785,378

(1) The present value of estimated future net cash flow includes the Alberta Royalty Tax Credit and is stated before deduction of income tax. **Estimated future net cash flow is not to be construed as the fair market value of our reserves.**

Reserves as of January 1, 2002
U.S. Presentation
(Net Reserves Using Constant Prices and Costs)

					Estimated Future Net Cash Flow(1)	
	Crude Oil	**Natural Gas Liquids**	**Natural Gas**	**Total**	**Undiscounted**	**Discounted at 10%**
	(MBbls)	**(MBbls)**	**(MMcf)**	**(MBoe)**	**(in thousands)**	
Proved reserves:						
Developed producing	73,302	9,432	558,990	175,899	$ 2,040,855	$ 1,088,148

					Estimated Future Net Cash Flow[1]	
Developed non-producing	527	349	46,461	8,620	110,681	62,525
Undeveloped	6,320	1,218	139,485	30,785	265,004	111,270
Total proved reserves	80,149	10,999	744,936	215,304	$ 2,416,540	$ 1,261,942

(1)
The present value of estimated future net cash flow includes the Alberta Royalty Tax Credit and is stated before deduction of income tax. **Estimated future net cash flow is not to be construed as the fair market value of our reserves.**

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Summary Financial Data

The following table presents our summary consolidated historical financial data for the years ended December 31, 1999, 2000 and 2001 and for the nine months ended September 30, 2001 and 2002 and our balance sheet data at September 30, 2002, actual and adjusted to reflect the acquisition of Celsius and further adjusted for this offering and the application of the proceeds therefrom. The table also presents our pro forma income statement data for the year ended December 31, 2001 reflecting the merger of Enerplus Resources Fund and EnerMark Income Fund on June 21, 2001. The information for the years ended December 31, 1999, 2000 and 2001 is derived from our audited consolidated financial statements contained in this prospectus, and the information as at September 30, 2002 and for the nine months ended September 30, 2001 and 2002 is derived from our unaudited consolidated interim financial statements contained in this prospectus. The financial data of the Fund for the years ended December 31, 1999 and 2000 is that of EnerMark Income Fund. The financial data of the Fund for the year ended December 31, 2001 and the nine months ended September 30, 2001 includes only EnerMark Income Fund's operating results prior to the merger and the results of the merged Fund thereafter. All disclosures of trust units and per trust unit data up to the June 21, 2001 merger date have been restated using the merger exchange ratio of 0.173 of a trust unit of Enerplus Resources Fund for each trust unit of EnerMark Income Fund. See "Presentation of Our Financial and Operational Information."

You should read the following data along with our "Management's Discussion and Analysis of Operating Results and Financial Condition" and our consolidated financial statements and related notes included in this prospectus. The historical results are not necessarily indicative of results to be expected in future periods.

The unaudited pro forma income statement and other data gives effect to the merger between Enerplus Resources Fund and EnerMark Income Fund, and the other transactions and adjustments as described in the notes to the pro forma statements, as if they had occurred on January 1, 2001. You should read the pro forma data together with our unaudited pro forma consolidated financial statements and related notes included in this prospectus as well as the consolidated financial statements and related notes included in this prospectus. The pro forma financial data may not be indicative of the results that would have occurred if the merger had been consummated as of January 1, 2001 or that will be obtained in the future.

	Year Ended December 31,				Nine Months Ended September 30,	
	1999	2000	2001	Pro Forma 2001	2001	2002
Income Statement Data:			(in thousands, except per trust unit amounts)			
Revenues:						
Oil and gas sales	$ 169,541	$ 343,182	$ 639,379	$ 761,722	$ 492,420	$ 428,408
Crown, freehold and other royalties	(32,145)	(80,943)	(132,660)	(158,314)	(115,568)	(88,515)
Interest and other income	1,045	611	858	1,035	680	338
Net revenues	138,441	262,850	507,577	604,443	377,532	340,231
Expenses:						

	Year Ended December 31,				Nine Months Ended September 30,	
Operating	37,228	54,997	120,082	138,218	81,157	95,853
General and administrative	5,726	7,202	12,971	14,940	6,367	10,085
Management fees	2,204	4,556	9,323	12,478	6,957	13,571
Interest	9,078	15,322	17,605	20,322	13,473	12,705
Depletion, depreciation and amortization	61,857	80,309	194,080	217,857	135,885	158,906
Total expenses	116,093	162,386	354,061	403,815	243,839	291,120
Income before taxes	22,348	100,464	153,516	200,628	133,693	49,111
Taxes:						
Capital taxes	1,551	2,936	4,722	5,248	3,624	3,950
Future income taxes	(4,957)	15,378	(31,475)	(31,201)	(13,260)	(19,338)
Net income	$ 25,754	$ 82,150	$ 180,269	$ 226,581	$ 143,329	$ 64,499

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	Year Ended December 31,				Nine Months Ended September 30,	
	1999	2000	2001	Pro Forma 2001	2001	2002
	(in thousands, except per trust unit amounts)					
Net income per trust unit:						
Basic	$ 1.25	$ 3.06	$ 3.28	$ 3.50	$ 2.82	$ 0.92
Diluted	1.25	3.05	3.28	3.50	2.82	0.92
Weighted average number of trust units outstanding:						
Basic	20,532	26,841	54,907	64,762	50,738	70,066
Diluted	20,607	26,928	54,956	64,811	50,817	70,181
U.S. GAAP						
Net income (loss)	$ 48,024	$ 98,261	$ (261,288)[1]	$ (191,199)[1]	$ (282,686)[1]	$ 83,211
Net income (loss) per trust unit:						
Basic	$ 2.34	$ 3.66	$ (4.76)	$ (2.95)	$ (5.57)	$ 1.19
Diluted	2.33	3.65	(4.76)	(2.95)	(5.57)	1.19
Other Financial Data:						
EBITDA[2]	$ 93,283	$ 196,095	$ 365,201	$ 438,807	$ 283,051	$ 220,722
Capital expenditures, before acquisitions and divestitures	$ 20,771	$ 39,996	$ 143,280	N/A	$ 94,983	$ 101,040
Cash available for distribution[3]	$ 78,189	$ 168,181	$ 316,454	$ 364,613	$ 253,868	$ 170,506
Cash available for distribution per trust unit[4]	$ 3.70	$ 5.49	$ 5.67	$ 5.63	$ 4.77	$ 2.40

September 30, 2002

	September 30, 2002		
	Actual	As Adjusted for Celsius	As Further Adjusted for this Offering(5)
		(in thousands)	
Balance Sheet Data:			
Property, plant and equipment (net)	$ 2,170,796	N/A	N/A
Total assets	2,255,129	N/A	N/A
Long-term debt	362,458	$ 528,358	$ 357,458
Unitholders' equity	1,404,138	1,404,138	1,575,038
U.S. GAAP			
Unitholders' equity	837,273	837,273	1,008,173

(1) As of September 30, 2001 and December 31, 2001, the application of the ceiling test under U.S. GAAP created a write-down of $744.3 million ($458.4 million after tax). In comparison, under Canadian GAAP, no write-down was required. Please read Note 8 to our unaudited consolidated financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001.

(2) EBITDA represents earnings before interest expense, taxes, depreciation, depletion and amortization. We have calculated EBITDA as net income plus the following expenses: interest, capital taxes and depletion, depreciation and amortization and future income tax provision (recovery). EBITDA is presented because we believe it is frequently used by securities analysts and others in evaluating companies and their ability to pay interest costs and make cash distributions. However, EBITDA should not be considered as an alternative to net revenue as a measure of liquidity or as an alternative to net income as an indicator of our operating performance or any other measure of performance in accordance with Canadian GAAP or U.S. GAAP. EBITDA, as we use the term herein, may not be comparable to EBITDA as reported by other entities.

(3) Cash available for distribution represents distributions relating to cash flow generated in the applicable year or nine month period which were actually paid to unitholders from March of such period through and including February of the following year, or with respect to a nine month period, through and including November of such year.

(4) Calculated using the actual number of trust units outstanding at the applicable record date, except for pro forma 2001, which is calculated using the weighted average number of trust units outstanding.

(5) Adjusted for both the acquisition of Celsius on October 21, 2002 and the sale of 7,000,000 trust units at a price of $26.00 per trust unit and the application of the net proceeds as described in "Use of Proceeds."

Canadian Federal Income Tax Considerations

A unitholder who is resident in Canada for purposes of the *Income Tax Act* (Canada) will be required to include, in computing income for a particular taxation year, the aggregate of the unitholder's share of the income of the Fund that is either paid to the unitholder in that taxation year or becomes payable in that taxation year. Because of tax deductions available to the Fund, the amounts paid or payable to a unitholder in respect of a taxation year may exceed the income of the Fund for tax purposes for that year. The adjusted cost base of a unitholder's units will be reduced by the portion of any amount paid or payable to the unitholder by the Fund (other than the non-taxable portion of certain capital gains) that was not included in computing unitholder's income, and the unitholder will realize a capital gain in a year to the extent the adjusted cost base of the unitholder's units would otherwise be a negative amount. Please read "Certain Income Tax Considerations Canadian Federal Income Tax Considerations Taxation of Unitholders Resident in Canada."

United States Federal Income Tax Considerations

The Fund is treated as a foreign corporation and the trust units are treated as shares of stock of a foreign corporation for United States federal income tax purposes. Unless the Fund is treated as a passive foreign investment company, a United States unitholder will generally include the gross amount of distributions (unreduced by Canadian withholding taxes) received from the Fund as ordinary dividend income, to the extent of the Fund's accumulated earnings and profits determined for United States federal income tax purposes ("dividend"). Dividend income will not be eligible for the dividends received deduction. Distributions in excess of current and accumulated earnings and profits will first be treated as a return of capital to the extent of the unitholder's basis in his units, and thereafter, the excess will be treated as gain from the sale or exchange of units. Any Canadian withholding tax paid with respect to the dividends may, subject to certain limitations, be claimed as a foreign tax credit against the unitholder's United States federal income tax liability or may be claimed as a deduction for United States federal income tax purposes.

United States residents should receive a 1099-Div form which outlines the amounts of dividend income, return of capital, foreign tax paid and federal income tax withheld for use in preparing a unitholder's income taxes.

An entity exempt from United States federal income tax will not be subject to United States federal income tax resulting from its ownership and disposition of trust units unless the unitholder's investment in trust units is debt-financed. The ownership or sale of trust units by a regulated investment company or mutual fund will generate qualifying income to it, and a trust unit will be treated as a qualifying asset. Provided the Fund is not classified as a passive foreign investment company, a United States unitholder will generally recognize gain or loss on the sale or exchange of units equal to the difference between the amount realized by the unitholder on the sale and the unitholder's adjusted tax basis in his units. Assuming the trust units are held as capital assets, any gain or loss will be capital gain or loss and will be long-term capital gain or loss if the unitholder has held the units for more than one year at the time of sale or exchange.

The application of the passive foreign investment company provisions to us is uncertain, and we may be a passive foreign investment company, or a PFIC, for United States federal income tax purposes for the 2002 taxable year and in subsequent taxable years. If we were considered to be a PFIC, United States holders, other than most tax-exempt investors, would generally be subject to adverse tax rules.

Please read "Certain Income Tax Considerations United States Federal Income Tax Considerations for United States Holders" for a more detailed discussion of United States federal income tax considerations of investing in trust units.

Canadian Federal Income Tax Considerations for Non-Residents of Canada

Where the trust makes distributions to a unitholder that is not resident in Canada, the same considerations as those applicable to residents of Canada will generally apply, except that any distribution of income will generally be subject to Canadian withholding tax at the rate of 25%, unless such rate is reduced under the provisions of a tax treaty between Canada and the unitholder's jurisdiction of residence. Unitholders that are residents of the United States for purposes of the Canada United States Income Tax Convention (1980) may be entitled to a reduced withholding tax rate of 15%. An entity exempt from U.S. federal income tax may be subject to Canadian withholding tax. A gain realized on the disposition of trust units by a unitholder that is not resident in Canada will generally not be subject to Canadian income tax provided that the trust units do not constitute "taxable Canadian property" of the unitholder. See "Certain Income Tax Considerations Canadian Federal Income Tax Considerations Taxation of Unitholders Not Resident in Canada."

RISK FACTORS

Trust units are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in the same business. You should carefully consider the following risk factors, together with other information contained in this prospectus and the information incorporated by reference, before investing in the trust units.

Risks Related to Our Business

Volatility in oil and natural gas prices could have a material adverse effect on our results of operations and financial condition which, in turn, could affect the market price of our trust units and the amount of distributions to our unitholders.

Our results of operations and financial condition are dependent on the prices we receive for the oil and natural gas we sell. Oil and natural gas prices have fluctuated widely during recent years and are likely to continue to be volatile in the future. Oil and natural gas prices may fluctuate in response to a variety of factors beyond our control, including:

- global energy policy, including the ability of OPEC to set and maintain production levels and prices for oil;
- political conditions, including the risk of hostilities in the Middle East;
- global and domestic economic conditions;
- weather conditions;
- the supply and price of imported oil and liquified natural gas;
- the production and storage levels of North American natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity of reserves to, and capacity of, transportation facilities;
- the effect of worldwide energy conservation measures; and
- government regulations.

Any decline in crude oil or natural gas prices may have a material adverse effect on our operations, financial condition, borrowing ability, reserves and the level of expenditures for the development of our oil and natural gas reserves. Any resulting decline in our cash flow could reduce distributions.

We use financial derivative instruments and other hedging mechanisms to try to limit a portion of the adverse effects resulting from volatility in natural gas and oil commodity prices. To the extent we hedge our commodity price exposure, we forego the benefits we would otherwise experience if commodity prices were to increase. In addition, our commodity hedging activities could expose us to losses. These losses could occur under various circumstances, including if the other party to our hedge does not perform its obligations under the hedge agreement or our hedging policies and procedures are not followed.

An increase in operating costs or a decline in our production level could have a material adverse effect on our results of operations and financial condition and, therefore, could reduce distributions to our unitholders.

Higher operating costs for the underlying properties of EnerMark and ERC will directly decrease the amount of cash flow received by the Fund and, therefore, may reduce distributions to our unitholders. Electricity, chemicals, supplies, reclamation and abandonment and labour costs are a few of our operating costs that are susceptible to material fluctuation.

The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in production could result in materially lower revenues and cash flow and, therefore, could reduce the amount available for distributions to our unitholders.

Our distributions may be reduced during periods in which we make capital expenditures or debt repayments using cash flow.

To the extent that either EnerMark or ERC uses cash flow to finance acquisitions, development costs and other significant capital expenditures, the net cash flow that the Fund receives from them will be reduced. Hence, the timing and amount of capital expenditures may affect the amount of net cash flow received by the Fund and, as a consequence, the amount of cash available to distribute to our unitholders. Therefore, distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made.

The board of directors of EnerMark has the discretion to determine the extent to which cash flow from our Operating Companies will be allocated to the payment of debt service charges as well as the repayment of outstanding debt. Funds used for such purposes will not be payable to the Fund. As a consequence, the amount of funds retained by the Operating Companies to pay debt service charges or reduce debt will reduce the amount of cash distributed to our unitholders during those periods in which funds are so retained.

A decline in our ability to market our oil and natural gas production could have a material adverse effect on our production levels or on the price that we receive for our production which, in turn, could reduce distributions to our unitholders.

Our business depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. Canadian federal and provincial, as well as United States federal and state, regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect our ability to produce and market oil and natural gas. If market factors change and inhibit the marketing of our production, overall production or realized prices may decline, which could reduce distributions to our unitholders.

Fluctuations in foreign currency exchange rates could adversely affect our business.

The price that we receive for a majority of our oil and natural gas is based on United States dollar denominated benchmarks, and therefore the price that we receive in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the United States dollar may negatively impact our net production revenue by decreasing the Canadian dollars we receive for a given United States dollar price. Currently, we do not engage in significant risk management activities related to foreign exchange rates, with the exception of the cross-currency swap associated with the senior unsecured notes.

If we are unable to acquire additional reserves, the value of our trust units and our distributions to unitholders may decline.

We do not explore for oil and natural gas reserves. Instead we add to our oil and natural gas reserves primarily through acquisitions. As a result, our future oil and natural gas reserves are highly dependent on our success in acquiring additional reserves. We also distribute the majority of our net cash flow to our unitholders rather than reinvest it in reserve additions. Hence, if capital from external sources is not available on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves will be impaired. Even if the necessary capital is available, we cannot assure you that we will be successful in acquiring additional reserves on terms that meet our investment objectives. Without these reserve additions, our reserves will deplete and, as a consequence, either our production or the average reserve life of our reserves will decline. Either decline may result in a reduction in the value of our trust units and in a reduction in cash available for distribution to our unitholders.

Our actual reserves will vary from our reserve estimates, and those variations could be material.

The value of our trust units depends upon, among other things, the reserves attributable to our properties. Estimating reserves is inherently uncertain. Ultimately, actual reserves attributable to our properties will vary from estimates, and those variations may be material. The reserve information contained in this prospectus, or contained in documents incorporated by reference into this prospectus, are only estimates. A number of factors are considered and a number of assumptions are made when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;

future commodity prices, production and development costs, royalties and capital expenditures;

initial production rates;

production decline rates;

ultimate recovery of reserves;

success of future exploitation activities;

marketability of production;

effects of government regulation; and

other government levies that may be imposed over the producing life of reserves.

Reserve estimates are based on the relevant factors, assumptions and prices on the date the evaluations were prepared. Many of these factors are subject to change and are beyond our control. If these factors, assumptions and prices prove to be inaccurate, our actual reserves could vary materially from our reserve estimates.

If we expand our operations beyond oil and natural gas production in western Canada, we may face new challenges and risks. If we are unsuccessful in managing these challenges and risks, our results of operations and financial condition could be adversely affected.

Our operations and expertise are currently focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin. In the future, we may acquire oil and gas properties outside this geographic area. In addition, our trust indenture does not limit our activities to oil and gas production and development, and we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of our activities into new areas may present challenges and risks that we have not faced in the past. If we do not manage these challenges and risks successfully, our results of operations and financial condition could be adversely affected.

In determining the purchase price of acquisitions, we rely on estimates of reserves that may prove to be inaccurate.

The price that we are willing to pay for reserve acquisitions is based largely on our estimates of the reserves to be acquired. Actual reserves could vary materially from these estimates. Consequently, the reserves we acquire may be less than we expected, which could adversely impact our cash flows and distributions to our unitholders.

An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods and approaches than those of our engineers, and these initial assessments may differ significantly from our subsequent assessments.

Since many of our properties are not operated by us, our results of operations may be adversely affected by the failure of third-party operators.

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the ability of the operators of our properties. At September 30, 2002, approximately 35% of our daily production was from properties operated by third parties. To the extent a third-party operator fails

to perform these duties properly or becomes insolvent, then our cash flows may be reduced. Third party operators also make estimates of future capital expenditures more difficult.

Further, the operating agreements that govern the properties not operated by us typically require the operator to conduct operations in a good and "workmanlike" manner. These operating agreements generally provide, however, that the operator has no liability to the other non-operating working interest owners, such as our unitholders, for losses sustained or liabilities incurred, except for liabilities that may result from gross negligence or wilful misconduct.

Delays in business operations could adversely affect our distributions to unitholders.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of cash available for distribution to our unitholders in a given period and expose us to additional third party credit risks.

Our indebtedness may limit the timing or amount of the distributions that we pay to our unitholders.

The payments of interest and principal with respect to our indebtedness reduces amounts available for distribution to our unitholders. EnerMark and ERC have available to them a $432 million unsecured credit facility that has variable interest rates. In addition, we swapped EnerMark's US$175 million aggregate principal amount of senior unsecured notes with fixed interest rates into $268 million of Canadian dollar denominated floating rate debt. Variations in interest rates and scheduled principal repayments could result in significant changes to the amount of the Operating Companies' cash flows required to be applied to their debt before payment of any amounts by them to the Fund. The agreements governing this credit facility and the senior unsecured notes each stipulate that if we are in default, exceed certain borrowing thresholds or fail to comply with certain covenants, the Fund's ability to make distributions to you may be restricted. Please read "Management's Discussion and Analysis of Operating Results and Financial Condition Liquidity and Capital Resources" for additional information. In addition, the Fund's right to receive payments from the Operating Companies is expressly subordinated to the rights of the lenders under the credit facility and the holders of the senior unsecured notes.

Our credit facility and any replacement credit facility may not provide sufficient liquidity.

The amounts available under our credit facility may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. Our credit facility is available on a one year revolving basis. If the lenders do not extend the facility at the end of the annual revolving period, the loan will convert to a two year term loan. If this occurs, we may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on our business, and distributions to our unitholders may be materially reduced.

We may be unable to compete successfully with other organizations in our industry.

The oil and natural gas industry is highly competitive. We compete for capital, acquisitions of reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than us. Some of these organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a worldwide basis. As a result of these complementary activities, some of our competitors may have greater and more diverse competitive resources to draw on than we do.

The industry in which we operate exposes us to potential liabilities that may not be covered by insurance.

Our operations are subject to all of the risks normally associated with the operation and development of oil and natural gas properties, including the drilling of oil and natural gas wells and the production and transportation of oil and natural gas. These risks and hazards include encountering unexpected formations or pressures, blow-outs, craterings and fires, all of which could result in personal injury, loss of life or environmental and other damage to our property and the property of others. We cannot fully protect against all of these risks, nor are all of these risks insurable. We may become liable for damages arising from these events against which we cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Any costs incurred to repair these damages or pay these liabilities would reduce funds available for distribution to our unitholders.

Our operation of oil and natural gas wells could subject us to environmental claims and liability.

The oil and natural gas industry is subject to extensive environmental regulation pursuant to local, provincial and federal legislation. A breach of that legislation may result in the imposition of fines or the issuance of "clean up" orders. Legislation regulating our industry may be changed to impose higher standards and potentially more costly obligations. For example, the 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change, known as the Kyoto Protocol, which would require (among other things) significant reductions in greenhouse gases, may be ratified by Canada in the near future. Although the implications are unknown at this time, if Kyoto is ratified it may result in significant additional costs for our operations. We do not establish a separate reclamation fund for the purpose of funding our estimated future environmental and reclamation obligations. We cannot assure you that we will be able to satisfy our future environmental and reclamation obligations.

We are not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms. Accordingly, our properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons.

Any site reclamation or abandonment costs incurred in the ordinary course in a specific period will be funded out of cash flows and, therefore, will reduce the amounts available for distribution to our unitholders. Should we be unable to fully fund the cost of remedying an environmental claim, we might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

Lower oil and gas prices increase the risk of write-downs of our oil and gas property investments.

Under Canadian accounting rules, the net capitalized cost of oil and gas properties may not exceed a "ceiling limit" that is based, in part, upon estimated future net cash flows from reserves. If the net capitalized costs exceed this limit, we must charge the amount of the excess against earnings. If oil and natural gas prices decline, our net capitalized cost may exceed this cost ceiling, ultimately resulting in a charge against our earnings. Under United States GAAP, the cost ceiling is generally lower than under Canadian GAAP because the future net cash flows used in the United States ceiling test are discounted to a present value. Accordingly, we would have more risk of a ceiling test write-down in a declining price

environment if we reported under United States GAAP. While these write-downs would not affect cash flow, the charge to earnings could be viewed unfavourably in the market.

Unforeseen title defects may result in a loss of entitlement to production and reserves.

We conduct title reviews in accordance with industry practice prior to any purchase of resource assets. However, these reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat our title to the purchased assets. If this type of defect were to occur, our entitlement to the production and reserves from the purchased assets could be jeopardized and, as a result, distributions to our unitholders may be reduced.

Risks Related to Our Structure and the Ownership of Our Trust Units

Changes in tax and other laws may adversely affect unitholders.

Income tax laws, other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource allowance, may in the future be changed or interpreted in a manner that adversely affects the Fund and our unitholders. Tax authorities having jurisdiction over us or our unitholders may disagree with how we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of our unitholders.

There would be material adverse tax consequences if the Fund lost its status as a mutual fund trust under Canadian tax laws.

We intend that the Fund continue to qualify as a mutual fund trust for purposes of the *Income Tax Act* (Canada). The Fund may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should the status of the Fund as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Fund and the unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- The Fund would be taxed on certain types of income distributed to unitholders, including income generated by the royalties held by the Fund. Payment of this tax may have adverse consequences for some unitholders, particularly unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.

- The Fund would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws if it ceased to be a mutual fund trust.

- Trust units held by unitholders that are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of trust units held by them.

- Our trust units would not constitute qualified investments for Registered Retirement Savings Plans, or "RRSPs," Registered Retirement Income Funds, or "RRIFs," Registered Education Savings Plans, or "RESPs," or Deferred Profit Sharing Plans, or "DPSPs." If, at the end of any month, one of these exempt plans holds trust units that are not qualified investments, the plan must pay a tax equal to 1% of the fair market value of the trust units at the time the trust units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified trust units would be subject to taxation on income attributable to the trust units. If an RESP holds non-qualified trust units, it may have its registration revoked by the Canada Customs and Revenue Agency.

In addition, we may take certain measures in the future to the extent we believe them necessary to ensure that the Fund maintains its status as a mutual fund trust. These measures could be adverse to certain holders of our trust units. See "Description of the Trust Units."

United States unitholders may be subject to passive foreign investment company rules.

We may be a passive foreign investment company for United States federal income tax purposes for the 2002 taxable year and in subsequent taxable years. If the Fund were classified as a passive foreign investment company, United States unitholders (other than most tax-exempt investors) would be subject to adverse tax rules. Under these adverse tax rules, United States unitholders generally would be required to allocate any gain or any excess distributions, which include any annual distributions other than in the first year the unitholder held our trust units, that is greater than 125% of the average annual distributions received by that unitholder in the three preceding taxable years or, if shorter, that unitholder's holding period for our trust units. The amount allocated to the current taxable year and any year prior to the first year in which we were a passive foreign investment company would be taxed as ordinary income in the current year. The amount allocated to each of the other taxable years would be subject to tax at the highest rate of tax in effect for the applicable class of taxpayer for that year, and an interest charge for the deemed deferral benefit would be imposed with respect to the resulting tax attributable to each of the other taxable years. Holders will not be able to make a "qualified electing fund" election or, with respect to the Fund's operating subsidiaries that were considered to be passive foreign investment companies, a "mark-to-market" election to protect themselves from these potential adverse consequences if we were ultimately determined to be a passive foreign investment company. United States unitholders are strongly urged to consult their own tax advisors regarding the United States federal income tax consequences of our possible classification as a passive foreign investment company and the consequences of such classification.

Your rights as a unitholder differ from those associated with other types of investments.

The trust units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in us. The trust units represent an equal fractional beneficial interest in the Fund and, as such, the ownership of the trust units does not provide unitholders with the statutory rights normally associated with ownership of shares of a corporation, including, for example, the right to bring "oppression" or "derivative" actions. The unavailability of these statutory rights may also reduce the ability of our unitholders to seek legal remedies against other parties on our behalf.

The trust units are also unlike conventional debt instruments in that there is no principal amount owing directly to unitholders. Our trust units will have no value when reserves from our properties can no longer be economically produced or marketed. Unitholders will only be able to obtain a return of the capital they invested during the period when reserves may be economically recovered and sold. Accordingly, the distributions you receive over the life of your investment may not meet or exceed your initial capital investment.

Changes in market-based factors may adversely affect the trading price of our trust units.

The market price of our trust units is primarily a function of anticipated distributions to unitholders and the value of the properties owned by us. The market price of our trust units is therefore sensitive to a variety of market based factors, including, but not limited to, interest rates and the comparability of our trust units to other yield oriented securities. Any changes in these market-based factors may adversely affect the trading price of our trust units.

The operation of the Fund is entirely independent from the unitholders, and loss of our key management and other personnel could impact our business.

Unitholders are entirely dependent on the management of EnerMark and EGEM, our manager, with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves, the management and administration of all matters relating to our properties and the administration of the Fund. The loss of the services of key individuals, the termination of our management agreement with or the insolvency of EGEM could have a detrimental effect on the Fund. Investors should carefully consider whether they are willing to rely on the management of EnerMark and EGEM before investing in our trust units.

EGEM, our manager, may have interests that are different from, and conflict with, the interests of the Fund and unitholders.

There may be circumstances in which the interests of EGEM, its affiliates or entities managed by any of them will conflict with those of the Fund and our unitholders. EGEM or its affiliates may acquire oil and gas properties on its own behalf or on behalf of persons other than the Fund. EGEM or its affiliates may manage and administer those additional properties, as well as enter into other types of energy-related management, advisory and investment activities. Although EGEM has agreed to resolve all potential conflicts of interest in a manner that treats the Fund and the other party fairly, neither EGEM, nor its directors, officers or affiliates, carry on their full-time activities on behalf of Enerplus and, when acting on their own behalf or on behalf of others, may at times act in competition with the interests of Enerplus or our unitholders. Some of the directors and officers of EGEM are directors and officers of other organizations in the oil and gas industry. In the ordinary course of business, these other organizations may acquire properties or explore other business opportunities for the benefit of these other organizations that may be suitable for us.

You may experience future dilution.

One of our objectives is to continually add to our oil and gas reserves primarily through acquisitions. Because we do not reinvest all of our cash flow, our success is, in part, dependent on our ability to raise capital from time to time by selling trust units. Unitholders will suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not offset the additional number of trust units issued to acquire those assets. Unitholders may also suffer dilution in connection with future issuances of trust units to effect acquisitions.

The limited liability of our unitholders is uncertain.

Because of uncertainties in the law relating to investment trusts, there is a risk that a unitholder could be held personally liable for obligations of the Fund in respect of contracts or undertakings which the Fund enters into and for certain liabilities arising otherwise than out of contracts including claims in tort, claims for taxes and possibly certain other statutory liabilities. Although every written contract or commitment of the Fund must contain an express disavowal of liability of the unitholders and a limitation of liability to Fund property, such protective provisions may not operate to avoid unitholder liability. Notwithstanding our attempts to limit unitholder liability, unitholders may not be protected from liabilities of the Fund to the same extent that a shareholder is protected from the liabilities of a corporation. Further, although the Fund has agreed to indemnify and hold harmless each unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by the unitholder resulting from or arising out of that unitholder not having limited liability, we cannot assure you that any assets would be available in these circumstances to reimburse you for any such liability.

We have adopted a unitholders' rights plan that may discourage a take-over attempt.

Provisions contained in our unitholder rights plan could make it more difficult for a third party to acquire us, even if doing so might be beneficial to our unitholders. The rights plan imposes various procedural and other requirements on a potential bidder, including a requirement that a potential bidder keep the bid open for a period of at least 45 days and that the bid be accepted by unitholders holding at least 50% of the trust units, other than the trust units held by the potential bidder. In addition, if a unitholder acquires more than 20% of the outstanding trust units, other unitholders may, at the discretion of the board of EnerMark, acquire a number of trust units at 50% of the then prevailing market price, causing significant dilution to the 20% unitholder. Our management agreement also provides that in certain circumstances, including if a unitholder acquires more than 20% of the outstanding trust units, certain termination fees and costs would be payable to EGEM. These rights may have the effect of delaying or deterring a change of control of the Fund, and could limit the price that investors might be willing to pay in the future for our trust units.

The redemption rights of unitholders is limited.

Unitholders have a limited right to require the Fund to repurchase their trust units, which is referred to as a redemption right. See "Description of the Trust Units." It is anticipated that the redemption right will not be the primary mechanism for unitholders to liquidate their investment. Our ability to pay cash in connection with a redemption is subject to limitations. Any securities which may be distributed *in specie* to unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

The management agreement which engages EGEM purports to limit EGEM's fiduciary duties, and these contractual provisions may serve to limit or eliminate the amounts recoverable from EGEM by us or our unitholders.

The management agreement that engages EGEM purports to limit EGEM's fiduciary duties. So long as EGEM exercises the degree of care, diligence and skill outlined therein, it will not be liable to the unitholders. The management agreement also requires us to indemnify EGEM and its directors, officers and employees unless they fail to meet certain standards.

The ability of United States investors to enforce civil remedies may be limited.

We are a trust organized under the laws of Alberta, Canada, and our principal place of business is in Canada. Most of the directors and all of the officers of EnerMark and ERC and the representatives of the experts named in this prospectus are residents of Canada, and all or a substantial portion of their assets and our assets are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or against any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or the securities laws of any state within the United States.

Risk Relating to Arthur Andersen LLP

In connection with this offering, we would normally be required to obtain a written consent from Arthur Andersen LLP, independent public accountants, to our incorporation of their audit report covering the audited financial statements of Enerplus Resources Fund (prior to its merger with EnerMark Income Fund) for the fiscal years ended December 31, 2000, 1999 and 1998 incorporated into this prospectus and to file that consent with the SEC as an exhibit to the registration statement of which this prospectus forms a part and with the Canadian securities commissions. However, on June 3, 2002, Arthur Andersen LLP, which was an Ontario limited liability partnership separate from Arthur Andersen LLP in the U.S., ceased to practice public accounting in Canada, including at its Calgary, Canada office, from which we were primarily serviced. As a consequence, representatives of Arthur Andersen LLP are no longer available to provide a consent in connection with the filing of this prospectus with the Canadian securities commissions and the filing of the registration statement with the SEC. We filed our prospectus in Canada in reliance on a staff notice of the Canadian Securities Administrators and we filed our registration statement with the SEC in reliance on an SEC rule, each of which relieve an issuer from the obligation to obtain Arthur Andersen LLP consents in certain cases. As a result of Arthur Andersen LLP not having provided that consent, you will not be able to recover damages from Arthur Andersen LLP under Canadian securities legislation or Section 11 of the Securities Act of 1933 with respect to their audit report. Furthermore, Arthur Andersen LLP may not possess sufficient assets to satisfy any claims that may arise out of Arthur Andersen LLP's audit of those financial statements.

PRICE RANGE AND TRADING VOLUME OF TRUST UNITS

The trust units trade on the New York Stock Exchange under the symbol "ERF" and trade on the Toronto Stock Exchange under the symbol "ERF.UN." The trust units began trading on the New York Stock Exchange on November 17, 2000. The following table sets forth the high and low closing prices and average daily trading volume of the trust units on the New York Stock Exchange and the Toronto Stock Exchange for the periods indicated, as adjusted to reflect the one for six consolidation of trust units effective June 8, 2000.

	New York Stock Exchange			Toronto Stock Exchange		
	High (US$)	Low (US$)	Average Daily Trading Volume	High ($)	Low ($)	Average Daily Trading Volume
2002						
Fourth Quarter (to November 25, 2002)	US$18.27	US$16.54	183,715	$ 28.77	$ 25.99	171,101
Third Quarter	19.08	16.23	194,652	28.93	25.56	155,850
Second Quarter	18.55	15.95	130,169	28.19	25.35	157,869
First Quarter	16.49	14.50	74,595	26.22	23.01	123,672
2001						
Fourth Quarter	US$17.00	US$14.77	99,853	$ 26.55	$ 23.45	134,704
Third Quarter	19.45	14.60	121,344	29.11	22.99	166,969
Second Quarter	21.51	16.20	129,171	32.76	24.60	109,853
First Quarter	15.85	14.66	18,315	24.40	22.55	59,192
2000						
Fourth Quarter(1)	US$15.25	US$14.69	4,155	$ 23.10	$ 21.80	31,087
Third Quarter				24.55	21.25	26,829
Second Quarter				23.00	16.32	18,663
First Quarter				17.40	15.78	4,708

(1) Our trust units began trading on the New York Stock Exchange on November 17, 2000.

On November 25, 2002, the closing sale price of the trust units on the New York Stock Exchange was US$16.54 and on the Toronto Stock Exchange was $25.99.

DISTRIBUTIONS

Distributions are paid on the distribution payment date to unitholders of record on the corresponding record date. We have established the 20th day of each calendar month as a distribution payment date, with the 10th day of that month being the corresponding record date (with the exception of the January 20th payment date, which is preceded by a distribution record date of December 31st of the prior year). A distribution of $0.30 (US$0.19) per trust unit was paid in November 2002. The first distribution that purchasers in this offering will be eligible to receive will be the December 2002 distribution, to be paid on December 20, 2002 (so long as the purchaser is a unitholder of record on December 10, 2002). Distributions payable to United States holders are payable on the same date and are converted into U.S. dollars at noon on the record date for registered unitholders and noon on the distribution date for non-registered unitholders.

Distributions to unitholders that are not resident in Canada may be subject to Canadian withholding tax. Please read "Certain Income Tax Considerations Canadian Federal Income Tax Considerations Unitholders Not Resident in Canada" for a discussion of the Canadian withholding tax applicable to United States holders.

Distributable Income

The amount available to the Fund to pay distributions depends on the level of net cash flow received by the Fund from the Operating Companies pursuant to the royalty agreements and as interest, principal and dividend payments. The amount paid by the Operating Companies to the Fund pursuant to the royalties is calculated as described in the section entitled "Description of the Royalties and the Subordinated Note." Distributions for a period generally represent net cash flow of the Operating Companies from the period approximately two months prior to the period in which the distribution is made.

Distribution Policy

The amount of cash flow paid to the Fund is, in part, subject to the discretion of the board of directors of EnerMark since it must determine both the extent to which cash flow will be allocated to the repayment of debt, as well as the amount of cash flow to apply to capital expenditures. The board of directors of EnerMark regularly evaluates the Fund's distribution payout with respect to forecast cash flows, debt levels and capital expenditure plans. In the past, the level of cash retained for debt repayment has typically varied between 5% and 20% of total cash flow. For the nine months ended September 30, 2002, approximately 17% of the cash available for distribution was retained for debt repayment.

Distribution History

The Fund may, on or before any distribution record date, declare payable to the unitholders all or any part of the distributable income of the Fund. Please read "Description of the Trust Units Distributions of Distributable Income."

The cash flow available for distribution can vary significantly from period to period for a number of reasons, including fluctuations in: (1) the sales price that we realize for our oil and natural gas production (after hedging contract receipts and payments), (2) the quantity of oil and natural gas that we produce, (3) the cost to produce oil and natural gas and administer the Fund and the Operating Companies, (4) the amount of cash retained for debt service or repayment or to fund capital expenditures, and (5) foreign currency exchange rates and interest rates. In addition, the level of distributions per trust unit will be affected by the number of outstanding trust units. Please read "Management's Discussion and Analysis of Operating Results and Financial Condition Risk Management Strategy Sensitivity Analysis."

The following table summarizes the historical cash distributions paid by Enerplus Resources Fund (as pre-merger Enerplus prior to the June 21, 2001 merger with EnerMark Income Fund) since 1998. Distributions prior to 2000 have been adjusted to give effect to the one for six consolidation of our trust units effective June 8, 2000.

	Cash Distributions Paid by Enerplus Resources Fund				
	2002	2001	2000	1999	1998
Month of Payment					
January	$ 0.30	$ 0.40	$ 0.30	$ 0.15	$ 0.21
February	0.25	0.65	0.36	0.15	0.42
March	0.20	0.45	0.30	0.15	0.21
April	0.20	0.45	0.30	0.15	0.21
May	0.28	0.90	0.54	0.18	0.30
June	0.28	0.52	0.30	0.15	0.21
July	0.28	0.48	0.30	0.15	0.18
August	0.28	0.50	0.43	0.30	0.18
September	0.28	0.45	0.30	0.18	0.18
October	0.30	0.40	0.30	0.24	0.15
November	0.30	0.40	0.75	0.36	0.15
December		0.35	0.40	0.30	0.15
Total	$ 2.95	$ 5.95	$ 4.58	$ 2.46	$ 2.55

EnerMark Income Fund

The following table summarizes EnerMark Income Fund's historical cash distributions from 1998 until the merger with Enerplus Resources Fund on June 21, 2001, without giving effect to the 0.173 exchange ratio for Enerplus trust units pursuant to the merger.

	Cash Distributions Paid by EnerMark Income Fund			
	2001	2000	1999	1998
Month of Payment				
January	$ 0.08	$ 0.06	$ 0.03	$ 0.075
February	0.13	0.06	0.04	0.075
March	0.09	0.06	0.03	0.075
April	0.09	0.06	0.03	0.075
May	0.17	0.09	0.05	0.075
June	0.09	0.06	0.03	0.055
July		0.06	0.03	0.055
August		0.09	0.09	0.055
September		0.06	0.05	0.055
October		0.06	0.05	0.040
November		0.12	0.10	0.045
December		0.08	0.06	0.040
Total	$ 0.65	$ 0.86	$ 0.59	$ 0.720

The historical distribution payments described above may not be reflective of future distribution payments, for the reasons described above and elsewhere in this prospectus. There is no guaranteed minimum distribution payable in any period.

USE OF PROCEEDS

We estimate that the net proceeds of the offering will be approximately $170.9 million (US$108.7 million) after deducting underwriting discounts and estimated expenses of the offering, based on an offering price of $26.00 (US$16.54) per trust unit. The estimated net proceeds will increase to $196.8 million (US$125.2 million) if the underwriters exercise their over-allotment option in full. The U.S. dollar information is based on an exchange rate of US$0.6362 per Cdn$1.00. Please read "Exchange Rates."

We will use the net proceeds to reduce outstanding borrowings under our credit facilities. Please read "Underwriting." These outstanding borrowings were incurred in connection with our acquisition of Celsius and our capital development program. Our credit facilities may thereafter be drawn upon from time to time to finance acquisitions, including those described under "Recent Developments Potential Acquisitions," or development projects or for general working capital purposes. Consistent with our business strategy, we continually pursue and evaluate acquisition opportunities. However, we cannot predict whether any of these opportunities will result in the completion of an acquisition by Enerplus.

CAPITALIZATION

The following table sets forth our consolidated capitalization:

- as of December 31, 2001 and September 30, 2002;
- as adjusted as of September 30, 2002 to give effect to our acquisition of Celsius; and
- as further adjusted as of September 30, 2002 also to give effect to our sale of 7,000,000 trust units in this offering (at an issue price of Cdn$26.00 (US$16.54) per trust unit) and the application of the net proceeds as described in "Use of Proceeds."

Our consolidated capitalization as adjusted assumes no exercise of the underwriters' over-allotment option. You should read this table together with the historical consolidated financial statements and the related notes included in this prospectus and the section entitled "Management's Discussion and Analysis of Operating Results and Financial Condition."

	December 31, 2001	September 30, 2002		
	Actual	Actual	As Adjusted for Celsius	As Further Adjusted for this Offering
	(in thousands)			
Long-term debt:[1]				
Bank credit facilities	$ 412,589	$ 94,130	$ 260,030	$ 89,130
Senior unsecured notes[2]		268,328	268,328	268,328
Total long-term debt	412,589	362,458	528,358	357,458
Unitholders' equity[3][4]	1,373,085	1,404,138	1,404,138	1,575,038
Total capitalization	$ 1,785,674	$ 1,766,596	$ 1,932,496	$ 1,932,496

(1) For additional information regarding our long-term debt, please read Note 4 to our unaudited consolidated financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001 contained in this prospectus.

(2)
Senior unsecured notes are US$175 million principal amount swapped into Cdn$268.3 million through a cross-currency swap. Please read "Recent Developments Issuance of Senior Unsecured Notes" and Note 4 to our unaudited consolidated financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001 contained in this prospectus.

(3)
Does not include (i) options outstanding under the Fund's trust unit option plan to acquire 150,000 trust units at exercise prices ranging from $15.30 to $22.90 per trust unit and expiring at various dates to December 31, 2004, and (ii) rights outstanding under our trust unit rights incentive plan to purchase 1,348,000 trust units at exercise prices ranging from $24.38 to $26.40 per trust unit and expiring at various dates from December 31, 2005 to December 31, 2008. For additional information regarding our trust unit option plan and trust unit rights incentive plan, please read Note 2 to our unaudited consolidated financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001 contained in this prospectus.

(4)
Unlimited trust units authorized; 69,532,000 trust units issued and outstanding, December 31, 2001; 74,751,000 trust units issued and outstanding, September 30, 2002 and as adjusted for Celsius at September 30, 2002; and 81,751,000 trust units issued and outstanding, as further adjusted for this offering at September 30, 2002.

SELECTED FINANCIAL DATA

The following table presents our selected consolidated historical financial data as at and for the years ended December 31, 1999, 2000 and 2001 and as at September 30, 2002 and for the nine months ended September 30, 2001 and 2002. The information for the years ended December 31, 1999, 2000 and 2001 is derived from our audited consolidated financial statements contained in this prospectus, and the information as at September 30, 2002 and for the nine months ended September 30, 2001 and 2002 is derived from our unaudited consolidated interim financial statements contained in this prospectus. The financial data of the Fund for the years ended December 31, 1999 and 2000 is that of EnerMark Income Fund. The financial data of the Fund for the year ended December 31, 2001 and the nine months ended September 30, 2001 includes only EnerMark Income Fund's operating results prior to the merger and the results of the merged Fund thereafter. All disclosures of trust units and per trust unit data up to the June 21, 2001 merger date have been restated using the merger exchange ratio of 0.173 of a trust unit of Enerplus Resources Fund for each trust unit of EnerMark Income Fund. See "Presentation of Our Financial and Operational Information."

You should read the following data along with our "Management's Discussion and Analysis of Operating Results and Financial Condition" and our consolidated financial statements and related notes included in this prospectus. The historical results are not necessarily indicative of results to be expected in future periods.

	Year Ended December 31,			Nine Months Ended September 30,	
	1999	**2000**	**2001**	**2001**	**2002**
Income Statement Data:	(in thousands, except per trust unit amounts)				
Revenues:					
Oil and gas sales	$ 169,541	$ 343,182	$ 639,379	$ 492,420	$ 428,408
Crown, freehold and other royalties	(32,145)	(80,943)	(132,660)	(115,568)	(88,515)
Interest and other income	1,045	611	858	680	338
Net revenues	138,441	262,850	507,577	377,532	340,231
Expenses:					
Operating	37,228	54,997	120,082	81,157	95,853
General and administrative	5,726	7,202	12,971	6,367	10,085
Management fees	2,204	4,556	9,323	6,957	13,571
Interest	9,078	15,322	17,605	13,473	12,705
Depletion, depreciation and amortization	61,857	80,309	194,080	135,885	158,906

	Year Ended December 31,			Nine Months Ended September 30,	
Total expenses	116,093	162,386	354,061	243,839	291,120
Income before taxes	22,348	100,464	153,516	133,693	49,111
Taxes:					
Capital taxes	1,551	2,936	4,722	3,624	3,950
Future income taxes	(4,957)	15,378	(31,475)	(13,260)	(19,338)
Net income	$ 25,754	$ 82,150	$ 180,269	$ 143,329	$ 64,499
Net income per trust unit:					
Basic	$ 1.25	$ 3.06	$ 3.28	$ 2.82	$ 0.92
Diluted	1.25	3.05	3.28	2.82	0.92
Weighted average number of trust units outstanding:					
Basic	20,532	26,841	54,907	50,738	70,066
Diluted	20,607	26,928	54,956	50,817	70,181

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U.S. GAAP					
Net income (loss)	$ 48,024	$ 98,261	$ (261,288)[1]	$ (282,686)[1]	$ 83,211
Net income (loss) per trust unit:					
Basic	$ 2.34	$ 3.66	$ (4.76)	$ (5.57)	$ 1.19
Diluted	2.33	3.65	(4.76)	(5.57)	1.19
Other Financial Data:					
EBITDA[2]	$ 93,283	$ 196,095	$ 365,201	$ 283,051	$ 220,722
Capital expenditures, before acquisitions and divestitures	$ 20,771	$ 39,996	$ 143,280	$ 94,983	$ 101,040
Cash available for distribution[3]	$ 78,189	$ 168,181	$ 316,454	$ 253,868	$ 170,506
Cash available for distribution per trust unit[4]	$ 3.70	$ 5.49	$ 5.67	$ 4.77	$ 2.40
Balance Sheet Data (as at period end):					
Property, plant and equipment (net)	$ 556,285	$ 1,483,293	$ 2,178,316	N/A	$ 2,170,796
Total assets	576,901	1,567,952	2,284,253	N/A	2,255,129
Long-term debt	131,315	275,944	412,589	N/A	362,458
Unitholders' equity	367,854	752,002	1,373,085	N/A	1,404,138
U.S. GAAP					
Unitholders' equity	135,006	543,684	760,594	N/A	837,273

(1) As of September 30, 2001 and December 31, 2001, the application of the ceiling test under U.S. GAAP created a write-down of $744.3 million ($458.4 million after tax). In comparison, under Canadian GAAP, no write-down was required. Please read Note 8 to our unaudited consolidated financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001.

(2)

EBITDA represents earnings before interest expense, taxes, depreciation and amortization. We have calculated EBITDA as net income plus the following expenses: interest, capital taxes and depletion, depreciation and amortization and future income tax provision (recovery). EBITDA is presented because we believe it is frequently used by securities analysts and others in evaluating companies and their ability to pay interest costs and make cash distributions. However, EBITDA should not be considered as an alternative to net revenue as a measure of liquidity or as an alternative to net income as an indicator of our operating performance or any other measure of performance in accordance with Canadian GAAP or U.S. GAAP. EBITDA, as we use the term herein, may not be comparable to EBITDA as reported by other entities.

(3)
Cash available for distribution represents distributions relating to cash flow generated in the applicable year or nine month period which were actually paid to unitholders from March of such period through and including February of the following year, or with respect to a nine month period, through and including November of such year.

(4)
Calculated using the actual number of trust units outstanding at the applicable record date, except for pro forma 2001, which is calculated using the weighted average number of trust units outstanding.

SELECTED OPERATING INFORMATION

The following table contains a summary of certain of our operating information for the periods indicated. The operating information for 1999, 2000 and up to June 21, 2001 contained in the following table is only that of EnerMark Income Fund. Information attributable to the operations of pre-merger Enerplus is not included. Operating information of the merged Fund is included in the 2001 information from June 21, 2001 forward. Please read "Presentation of Our Financial and Operational Information."

	Year Ended December 31,			Nine Months Ended September 30, 2002
	1999	**2000**	**2001**	
Gross Daily Average Production:				
Oil and natural gas liquids (Bbls/day)	13,396	14,200	24,570	27,416
Natural gas (Mcf/day)	71,713	101,473	176,671	204,463
Total (Boe/day)	25,348	31,112	54,015	61,493
Average Realized Price:(1)				
Oil ($ per Bbl)	$ 23.26	$ 33.67	$ 31.21	$ 33.30
Natural gas ($ per Mcf)	2.33	4.53	5.60	3.43
Natural gas liquids ($ per Bbl)	16.14	32.33	31.12	23.06
Combined ($ per Boe)	18.32	30.14	32.43	25.52
Crown, freehold and other royalties ($ per Boe)	$ 3.47	$ 7.10	$ 6.73	$ 5.27
Operating costs ($ per Boe)	$ 4.02	$ 4.83	$ 6.09	$ 5.71

(1)
Average realized prices are inclusive of hedging activity. Please read "Business Risk Management."

MANAGEMENT'S DISCUSSION AND ANALYSIS OF OPERATING RESULTS AND FINANCIAL CONDITION

The following management's discussion and analysis of operating results and financial condition should be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2001 and 2000, and the interim unaudited consolidated comparative financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001 included in this prospectus. This discussion contains forward-looking statements that involve risks and uncertainties. For additional information regarding some of the risks and uncertainties that affect our business and the industry in which we operate and that apply to an investment in our trust units, please read "Risk Factors."

Our financial statements have been prepared in accordance with Canadian GAAP. Canadian GAAP differs in some significant respects from U.S. GAAP and thus our financial statements may not be comparable to the financial statements of U.S. companies. The principal differences as they apply to us are summarized in the notes to the financial statements included or incorporated by reference in this prospectus. All amounts are stated in Canadian dollars unless otherwise specified.

We have adopted the standard of 6 Mcf:1 barrel of oil equivalent when converting natural gas to barrels of oil equivalent. 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 indicated.

Overview

Enerplus is the largest conventional oil and gas trust in North America in terms of market capitalization, production volumes and oil and natural gas reserves. Our trust units are listed on the Toronto Stock Exchange and the New York Stock Exchange. Through our operating subsidiaries, we actively manage the acquisition, development, exploitation, and production of oil and natural gas properties. Our operations are currently focused exclusively on western Canada.

EnerMark and Enerplus Merger

On June 21, 2001, the respective unitholders of EnerMark Income Fund and Enerplus Resources Fund approved a merger combining the two funds. As the former unitholders of EnerMark Income Fund held approximately 69% of the outstanding trust units of the combined Fund at the date of acquisition, the merger has been accounted for using the reverse take-over method of accounting for business combinations. For accounting purposes, EnerMark Income Fund acquired Enerplus effective June 21, 2001 and continues as Enerplus Resources Fund.

Important Information Regarding Comparative Financial Statements

As a result of the reverse take-over accounting, our consolidated financial statements for the year ended December 31, 2001 include only EnerMark Income Fund's operating results prior to its merger with Enerplus Resources Fund on June 21, 2001 and include the results of the merged Fund thereafter. All comparative figures and references to prior years are those of EnerMark Income Fund. Thus, the historical financial information for the year 2000 is solely that of EnerMark Income Fund, and the comparison of the 2001 results with those of 2000 set forth below must be viewed in light of this accounting presentation. Additionally, unless otherwise indicated, all historical production, reserve and other operational information is based on the historical operations of EnerMark Income Fund, and the production, reserve and other operational information attributable to the operations of Enerplus Resources Fund as it existed prior to the merger with EnerMark Income Fund has only been included since June 21, 2001. This discussion and analysis refers to Enerplus as the combined fund, and information included herein has been restated, as applicable, to reflect the trust unit exchange ratio of 1.000 EnerMark Income Fund trust unit for 0.173 of an Enerplus trust unit, pursuant to the reverse take-over. Please read "Presentation of Our Financial and Operational Information."

Comparison of 2001 results with those of 2000 is also complicated by the fact that EnerMark Income Fund, as predecessor to Enerplus, completed several material acquisitions during 2000 and 2001.

Accordingly, the 2001 financial results include a full year of operations for the 2000 acquisitions, while the 2000 results reflect only a partial-year impact, commencing on the closing date of each acquisition. These acquisitions and their respective dates are as follows:

Corporate and Property Acquisition	Acquisition Cost[1]	Closing Date
	(in millions)	

Corporate and Property Acquisition		Acquisition Cost(1)	Closing Date
Kaybob (property)	$	25	September 26, 2001
Enerplus Resources Fund		679	June 21, 2001
Cabre Exploration Ltd. (purchase of remaining 11.35% interest)		33	January 8, 2001
Cabre Exploration Ltd. (purchase of 88.65% interest)		278	December 21, 2000
EBOC Energy Ltd.		155	September 1, 2000
Pursuit Resources Corp.		119	April 3, 2000
Hanna/Garden Plains (property)		34	February 28, 2000
Western Star Exploration Ltd.		27	January 7, 2000

(1)
Acquisition cost includes consideration paid, debt assumed and transaction and related costs and charges.

Results of Operations

Our results of operations are primarily affected by our realized prices for our oil and natural gas production, the quantities of oil and natural gas that we produce, and the costs we incur in connection with our production, acquisition and development activities. Commodity prices can be very volatile, and we generally sell our production at rates that are related to current market prices. We attempt to lessen the impact of changing commodity prices to some extent by hedging a portion of our production. The quantities of oil and natural gas that we produce tends to decrease over time due to natural reservoir depletion. We seek to offset these production declines through development of existing properties and acquisition of new properties. We have identified numerous development opportunities within our existing properties and pursue these opportunities in accordance with our capital budget. We also continually evaluate oil and gas reserve acquisition opportunities, although the quantity, quality and price of available acquisition opportunities vary over time.

Nine Months Ended September 30, 2002 Compared to Nine Months Ended September 30, 2001

Overview.

On August 8, 2002 we acquired a 16% working interest in Oil Sands Lease #24 (also known as the Joslyn Creek Lease) for $16.4 million and the assumption of $4.1 million in contingent project debt.

On September 12, 2002 we closed an equity offering of 4,750,000 trust units at a price of $26.85 per trust unit for gross proceeds of $127.5 million.

We continued our active development program, investing $44.8 million in development drilling and facilities for the three months ended September 30, 2002 and $95.1 million for the nine months ended September 30, 2002. During the third quarter, we participated in the drilling of 135 gross wells (117.1 net wells) with a 99% success rate, and for the nine months ended September 30, 2002, we participated in the drilling of 226 gross wells (181.0 net wells) with a 99% success rate.

Subsequent to the end of the third quarter, we completed the acquisition of Celsius Energy Resources Ltd. for $165.9 million including working capital adjustments. We acquired daily production volumes of 5,750 Boe/day and 18 MMBoe of established reserves in connection with the acquisition. Please read "Recent Developments" and "Appendix B Information Regarding Celsius Energy Resources Ltd."

Production. Daily production averaged 60,730 Boe/day during the three months ended September 30, 2002, representing a 1% increase over production volumes of 60,331 Boe/day for the same period in 2001. Production remained relatively consistent over the periods as natural reservoir declines were more than offset by production gains from acquisition and development activity. This was particularly evident for crude oil as volumes increased 5% or 1,092 Bbls/day for the three months ended September 30, 2002 compared to the same period in 2001. The majority of this increase can be attributed to the property acquisition in the Medicine Hat Glauconite "C" area during the first quarter of 2002. Natural gas production during the third quarter 2002 was lower compared to the three months ended June 30, 2002 due to plant turnarounds and maintenance.

Production for the nine months ended September 30, 2002 increased 19% to 61,493 Boe/day compared to 51,523 Boe/day for the corresponding period in 2001. This increase is attributable to the reverse take-over of Enerplus Resources Fund by EnerMark Income Fund on June 21, 2001. Unlike the corresponding period in 2002, production for the first nine months of 2001 reflects the volumes of the combined Fund only from the date of the merger.

Production from the Celsius acquisition is not recorded in the third quarter as the transaction closed October 21, 2002. Production from the newly acquired Oil Sands Lease #24 is not expected until 2004.

Our average production portfolio for the three months ended September 30, 2002 was weighted 54% natural gas, 39% crude oil, and 7% natural gas liquids on a per Boe basis. Average production volumes are outlined below:

	Daily Sales Volumes					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2002	2001	% Change	2002	2001	% Change
Natural gas (Mcf/day)	198,452	199,823	(1)%	204,463	167,304	22%
Crude oil (Bbls/day)	23,560	22,468	5	23,117	19,760	17
NGLs (Bbls/day)	4,095	4,559	(10)	4,299	3,879	11
Total daily sales (Boe/day)	60,730	60,331	1	61,493	51,523	19

Pricing and Price Risk Management. Although the AECO monthly index price decreased 17% from $3.92/Mcf in 2001 to $3.25/Mcf in 2002, we experienced only a 2% decline in the average price (before hedging) received on natural gas from $3.43/Mcf for the three months ended September 30, 2001 to $3.37/Mcf for the same period in 2002. For the three months ended September 30, 2002, we had more fixed physical gas contracts that minimized the decrease in the realized price. For the nine months ended September 30, 2002, our natural gas prices (before hedging) decreased 39% from the comparable period 2001. This decline is consistent with the sharp reduction in the AECO and NYMEX price indices from the peak experienced during the first half of 2001.

The average price that we received for our crude oil (before hedging) increased 7% from $35.11/Bbl for the third quarter of 2001 to $37.41/Bbl in the same quarter in 2002, which corresponds with the increase in the price of benchmark West Texas Intermediate (WTI) crude oil after adjusting for the change in the US$ exchange rate. For the nine months ended September 30, 2002 the average price received for crude oil (before hedging) decreased 1% from the comparable period in 2001, lower than the 9% decrease in price of the WTI crude oil. This difference is mainly due to the different product mix recognized in 2002 because of the merger between Enerplus Resources Fund and EnerMark Income Fund.

The realized prices for natural gas liquids decreased 2% from the third quarter of 2001 to average $25.81/Bbl for the third quarter of 2002. For the nine months ended September 30, 2002, natural gas liquids prices decreased 34% from the comparable period in 2001. In both the three and nine month comparisons, the realized prices for natural gas liquids were influenced by the corresponding prices for natural gas.

	Average Selling Price (Before the Effects of Hedging)					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2002	2001	% Change	2002	2001	% Change

	Average Selling Price (Before the Effects of Hedging)					
Natural gas (per Mcf)	$ 3.37	$ 3.43	(2)%	$ 3.44	$ 5.68	(39)%
Crude oil (per Bbl)	37.41	35.11	7	33.69	33.93	(1)
NGLs (per Bbl)	25.81	26.29	(2)	23.06	34.79	(34)
Total daily sales (per Boe)	27.24	26.38	3	25.69	34.08	(25)

	Average Selling Price (Before the Effects of Hedging)					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2002	2001	% Change	2002	2001	% Change
AECO natural gas (per Mcf)	$ 3.25	$ 3.92	(17)%	$ 3.67	$ 7.30	(50)%
NYMEX natural gas (US$ per Mcf)	3.26	2.98	9	3.01	5.01	(40)
WTI crude oil (US$ per Bbl)	28.27	26.76	6	25.39	27.82	(9)
CDN$/US$ exchange rate	0.6398	0.6472	(1)	0.6369	0.6502	(2)

We continued to implement hedging transactions in accordance with our commodity price risk management program during the third quarter.

For the three months ended September 30, 2002, we realized a hedging gain of $0.8 million on natural gas and a hedging loss of $1.7 million on crude oil as a result of our price risk management program. This realized loss is mainly due to an improvement in the markets for crude oil while the realized gain was due to a decrease in natural gas prices during the period. For the nine months ended September 30, 2002, we realized a hedging loss on both natural gas and crude oil of $0.5 million and $2.4 million, respectively. For the comparable period in 2001, we realized a $3.1 million hedging loss on crude oil and a $16.2 million hedging gain on natural gas. The mark-to-market value of our forward commodity price contracts at September 30, 2002 represented an unrealized loss of $18.0 million for natural gas and an unrealized loss of $9.0 million for crude oil. In other words, if we were to settle our forward commodity price contracts at September 30, 2002 with reference to the forward market at that time, we would have to make a payment of approximately $27.0 million. The mark-to-market loss has widened from the second quarter because the forward prices for crude oil and natural gas had strengthened by September 30, 2002.

Oil and gas sales. Crude oil and natural gas revenues, including net hedging costs, were $151.3 million for the three months ended September 30, 2002, which was 8% lower than the $163.8 million reported for the same period in 2001. The decreased revenue was primarily due to a gain of $18.9 million realized in 2001 on natural gas hedging contracts. For the nine months ended September 30, 2002, crude oil and natural gas revenues, including net hedging costs, were $428.4 million compared to $492.4 million for the comparable period in 2001. The decrease is a result of lower product prices during 2002 and the $18.9 million gain realized in 2001, which were partially offset by the combined results reflected in 2002 from the merger of Enerplus Resources Fund and EnerMark Income Fund that occurred on June 21, 2002.

Royalties. Royalties decreased from $32.9 million or 20% of oil and gas sales for the three months ended September 30, 2001 to $29.0 million or 19% for the three months ended September 30, 2002. For the nine months ended September 30, 2002 royalties decreased from $115.6 million or 23% of oil and gas sales in 2001 to $88.5 million or 21% of oil and gas sales. In the three and nine month comparisons the decline in

royalties as a percentage of oil and gas sales is attributable to a lower reference gas price used to calculate Crown royalties during 2002.

Operating Expenses. Operating expenses totaled $34.7 million or $6.21/Boe for the three months ended September 30, 2002 compared to $34.7 million or $6.25/Boe for the three months ended September 30, 2001. Third quarter operating expenses tend to be higher as a result of increased maintenance costs, plant turnarounds and property tax charges which are incurred during this period. Operating expenses for the nine months ended September 30, 2002 increased 18% to $95.9 million from the comparable period in 2001 due to the merger between Enerplus Resources Fund and EnerMark Income Fund. However, after reflecting the higher production levels, operating expenses per Boe were reduced to $5.71/Boe from $5.77/Boe during this time period.

General and Administrative Expenses. General and administrative expenses were $3.4 million or $0.60/Boe for the three months ended September 30, 2002 compared to $1.6 million or $0.29/Boe for the same period in 2001. Net general and administrative costs for the third quarter of 2001 were lower than expected due to one-time adjustments for cost recoveries. General and administrative expenses for the nine months ended September 30, 2002 of $10.1 million are in line with our annual expectations of $0.60/Boe.

In accordance with the full cost method of accounting, we capitalized $2.0 million or 25% of gross general and administrative costs for the three months ended September 30, 2002 compared to $1.8 million or 28% for the same period in 2001. For the nine month period ended September 30, 2002, we capitalized $6.1 million of gross general and administrative costs compared to $4.6 million for the comparable period in 2001. The majority of these capitalized costs represent compensation costs for staff involved in development and acquisition activities.

Management Fees.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	**2001**	**2002**	**2001**
	(in millions)			
Base management fees	$ 2.3	$ 2.5	$ 6.3	$ 7.0
Performance fees	4.9		7.3	
Total management fees	$ 7.2	$ 2.5	$ 13.6	$ 7.0

Base management fees, which are calculated based on 2.75% of net operating income, decreased to $2.3 million during the three months ended September 30, 2002 from $2.5 million for the same period in 2001. The decrease is a result of lower net operating income experienced during the period. For the nine months ended September 30, 2002, base management fees decreased to $6.3 million from $7.0 million for the same period in 2001. The decrease in the nine month comparison is a result of lower net operating income experienced during the period, offset slightly by the increase in the rate used to calculate the base management fees from 2.20% to 2.75%, as a result of the restructured management fee associated with the merger between Enerplus Resources Fund and EnerMark Income Fund.

The performance fee can range between 0% and 4% of our annual operating income based on our total return and our relative performance compared to certain other Canadian conventional 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 September 30, 2002, the performance fee for 2002 would be 3.0% of net operating income. The $7.3 million is an estimate that may increase or decrease throughout the remainder of the year until the performance fee is calculated and finalized.

Interest Expense. Interest expense for the three months ended September 30, 2002 was $5.2 million, an increase from $5.1 million recognized during the comparable period of 2001. Although our average

long-term debt has decreased compared to the same period in 2001, the average floating interest rate paid by us has increased.

For the nine months ended September 30, 2002, interest expense was $12.7 million, a decrease from $13.5 million recognized during the comparable period of 2001. The decrease is attributable to lower outstanding average long-term debt along with a reduction in interest rates over the period.

As at September 30, 2002, we had floating interest rates with respect to $94.2 million in bank debt and $268.3 million in senior unsecured debentures. However, with respect to this long-term debt, we had $75.0 million in interest rate swaps that fixed the rate of interest before stamping fees between 3.89% and 4.70% for three-year terms. We expect the stamping fees, which vary depending on our ratio of debt to EBITDA, to generally range from 0.85% to 1.05%. Please read Note 5 to our unaudited consolidated financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001.

Depletion, Depreciation and Amortization. Depletion, depreciation and amortization decreased to $52.7 million or $9.42/Boe for the three months ended September 30, 2002 from $55.4 million or $9.98/Boe for the same period in 2001. Included in the 2001 balance are amortization costs related to deferred hedging assets amounting to $3.9 million that were fully amortized by the end of 2001. For the nine months ended September 30, 2002, depletion, depreciation and amortization was $158.9 million or $9.47/Boe compared to $135.9 million or

$9.66/Boe for the same period in 2001. These differences are a result of the merger between Enerplus Resources Fund and EnerMark Income Fund. Higher production volumes during 2002 have increased the amount of depletion, depreciation and amortization expense, while the change in the overall depletable reserves has decreased the rate of depletion, depreciation and amortization per Boe. When a ceiling test was applied to our capital assets as at September 30, 2002, no write-down was required.

Taxes. For the three months ended September 30, 2002, a future income tax recovery of $11.1 million was recorded in income. Under Canadian GAAP, we do not recognize any future income taxes, as taxable income is distributed to unitholders in the form of taxable distributions. However, our Operating Companies are required to account for future income taxes. Future income taxes for the Operating Companies are dependent upon the method by which funds are transferred to the Fund from the Operating Companies. The future income tax recovery occurs when tax deductible distributions, which can take the form of interest or royalties, are transferred from the Operating Companies to our unitholders. During the quarter, increased tax deductible distributions were made from the Operating Companies to us.

Netbacks. The following table illustrates our netbacks per Boe of production.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Oil and gas sales	$ 27.08	$ 29.51	$ 25.52	$ 35.01
Royalties	(5.19)	(5.94)	(5.27)	(8.22)
Operating expenses	(6.21)	(6.25)	(5.71)	(5.77)
Operating netback per Boe	$ 15.68	$ 17.32	$ 14.54	$ 21.02
General and administrative expenses	(0.60)	(0.29)	(0.60)	(0.45)
Management fees	(1.30)	(0.45)	(0.80)	(0.49)
Net interest	(0.92)	(0.90)	(0.74)	(0.91)
Capital taxes	(0.22)	(0.25)	(0.24)	(0.26)
Restoration and abandonment cash costs	(0.18)	(0.13)	(0.19)	(0.10)
Funds flow from operations	$ 12.46	$ 15.30	$ 11.97	$ 18.81

Net Income and Funds Flow From Operations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(in millions, except per trust unit amounts)			
Net income	$ 29.1	$ 25.1	$ 64.5	$ 143.3
Net income per trust unit (basic and diluted)	0.41	0.39	0.92	2.82
Funds flow from operations	69.6	85.0	200.9	264.6
Funds flow from operations per trust unit	0.98	1.31	2.87	5.22

The increase in net income for the three months ended September 30, 2002, is a result of higher average crude oil prices recognized during the third quarter 2002 compared to the same period in 2001, offset slightly by the additional performance fee that has been accrued during the period. The decrease in funds flow from operations for the three months ended September 30, 2002 is due to an $18.9 million gain recognized from natural gas hedging contracts during the same period in 2001.

The change in net income and funds flow from operations for the nine months ended September 30, 2002, is due to a combination of a $16.2 million gain recognized from natural gas hedging contracts during 2001, a sharp decline in natural gas prices realized during 2002 from those experienced during the first and second quarters of 2001 and the fact that the 2001 year to date results are those strictly of EnerMark Income Fund to the June 21, 2001 date of the merger between it and Enerplus Resources Fund.

Management monitors our 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 Enerplus' requirement to maintain a prudent capital structure.

With respect to the third quarter of 2002, we distributed $64.5 million, or $0.88 per trust unit in cash distributions to unitholders (94% of funds flow from operations) and withheld $3.9 million or $0.05 per trust unit for debt reduction (6% of funds flow from operations). For the nine month period, we distributed $170.5 million, or $2.40 per trust unit (83% of funds flow from operations), and withheld $33.9 million, or $0.48 per trust unit, for debt reduction (17% of funds flow from operations).

Cash available for distribution per trust unit of $0.88 for the three months ended September 30, 2002 represents what an Enerplus unitholder will have received from the production relating to the third quarter of 2002 (paid to unitholders on September 20, October 20, and November 20, 2002). Cash available for distribution was $1.25 per trust unit for the same period in 2001.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Overview.

On June 21, 2001, the unitholders of Enerplus Resources Fund and EnerMark Income Fund agreed to combine the two funds and continue as Enerplus Resources Fund.

In connection with the combination of the two funds, Enerplus restructured its management fee to better align the interests of EGEM and the unitholders by eliminating acquisition and divestment fees and replacing them with performance incentive fees.

Aside from the reverse take-over combination of Enerplus Resources Fund and EnerMark Income Fund, acquisitions net of dispositions of producing oil and gas properties totaled $8.9 million during the year ($77.4 million in acquisitions less $68.5 million in dispositions of non-core properties).

We invested $143.0 million in development projects in 2001, drilling 321.6 net wells.

Our commodity price risk management program generated a net gain of $50.1 million for the year ended December 31, 2001.

On November 15, 2001, we issued 4,312,500 trust units at a price of $24.75 per trust unit in a Canadian public offering.

Production. Daily production averaged 54,015 Boe/day during 2001, representing a 74% increase over production volumes of 31,112 Boe/day in 2000. The increase is primarily attributable to the reverse takeover of Enerplus Resources Fund by EnerMark Income Fund on June 21, 2001, as well as the acquisitions of Cabre, EBOC, Pursuit, and Western Star and the acquisition of the Hanna/Garden Plains property during 2000. The acquisitions in 2000 had a full year impact on 2001 production, but only a partial-year impact on 2000 production, relative to the respective closing date of the acquisition.

Average production volumes for the years ended December 31, 2001 and 2000 are outlined below.

	Daily Sales Volumes		
	2001	**2000**	**% Change**
Natural gas (Mcf/day)	176,671	101,473	74%
Crude oil (Bbls/day)	20,592	12,089	70

	Daily Sales Volumes		
Natural gas liquids (Bbls/day)	3,978	2,111	88
Total daily sales (Boe/day)	54,015	31,112	74

Our exit production rate averaged 62,300 Boe/day for the month of December 2001. Our total production for December 2001 was 56% natural gas, 37% crude oil and 7% natural gas liquids.

Pricing and Price Risk Management. The average price that we received for our natural gas before hedging increased 9% from $4.52/Mcf in 2000 to $4.91/Mcf in 2001. In comparison, the AECO monthly index increased 25% from $5.02/Mcf in 2000 to $6.30/Mcf in 2001 and the NYMEX index price increased 12% from $3.91/Mcf in 2000 to $4.38/Mcf in 2001. Our realized gas prices did not increase as much as the reference indices due to

- long-term fixed price physical delivery contracts representing approximately 5% of production that were priced below prevailing index prices in 2001, and

- sales to aggregators that were also priced below prevailing indices in 2001 because they reflect a basket of fixed, floating, and downstream delivery contracts.

The average price that we received for our crude oil (before hedging) decreased 15% from $35.86/Bbl in 2000 to $30.48/Bbl in 2001. This reflects a comparable 14% decline in the pricing of benchmark West Texas Intermediate (WTI) crude oil. While we benefited from the weaker Canadian exchange rate and a lighter average blend of crude oil as a result of recent acquisitions, these advantages were offset by wider price differentials on heavier streams of crude oil during the year.

The average price that we received for our natural gas liquids decreased 4% from $32.33/Bbl in 2000 to average $31.12/Bbl in 2001. However, the price of natural gas liquids as a proportion of our crude oil price increased from 90% in 2000 to 102% in 2001, reflecting significantly higher values attributed to ethane production in the first half of 2001.

	Average Selling Price (Before the Effects of Hedging)		
	2001	2000	% Change
Natural gas (per Mcf)	$ 4.91	$ 4.52	9%
Crude oil (per Bbl)	30.48	35.86	(15)
Natural gas liquids (per Bbl)	31.12	32.33	(4)
Total daily sales (per Boe)	29.89	30.94	(3)

	Average Selling Price (Before the Effects of Hedging)		
	2001	2000	% Change
AECO natural gas (per Mcf)	$ 6.30	$ 5.02	25%
NYMEX natural gas (US$ per Mcf)	4.38	3.91	12
WTI crude oil (US$ per Bbl)	25.97	30.19	(14)
CDN$/US$ exchange rate	0.6458	0.6736	(4)

In 2001, we realized a gain of $50.1 million as a result of our commodity hedging activities, compared to a loss of $9.1 million in 2000, as outlined below:

	Opportunity Gain (Loss) from Financial Hedging	
	2001	2000

	Opportunity Gain (Loss) from Financial Hedging	
	(in millions)	
Crude oil	$ 5.5	$ (9.6)
Natural gas	44.6	0.5
Net hedging opportunity gain (loss)	$ 50.1	$ (9.1)
Net gain (loss) per Bbl crude oil	0.73	(2.19)
Net gain per Mcf natural gas	0.69	0.01

We use forward and futures contracts to manage our exposure to commodity price fluctuations. Please read " Risk Management Strategy" for more information on these strategies.

Oil and Gas Sales. Revenues, including hedging gains, were $639.4 million for the year ended December 31, 2001, which was 86% higher than the $343.2 million reported for the year ended December 31, 2000. This increase was primarily due to the reverse takeover of Enerplus on June 21, 2001, as well as the acquisitions of Cabre, EBOC, Pursuit, and Western Star and the acquisition of the Hanna/Garden Plains property during 2000. The acquisitions in 2000 had a full year impact on 2001 revenues, but only a partial-year impact on 2000 revenues, depending on the closing date of the acquisition. Our 2001 increase in revenues was also the result of our production volumes being more heavily weighted towards lighter oil and hedging gains offset by a slight reduction in prices as described in the table below.

	Analysis of Sales Revenues			
	Crude Oil Revenues	NGLs Revenues	Natural Gas Revenues	Total Revenues
	(in millions)			
2000 Sales Revenues	$ 149.0	$ 25.0	$ 169.2	$ 343.2
Effect of increase (decrease) in product price	(40.4)	(1.8)	25.1	(17.1)
Effect of change in sales volumes	110.8	22.0	121.3	254.1
Effect of change in hedging gains	15.1		44.1	59.2
2001 Sales Revenues	$ 234.5	$ 45.2	$ 359.7	$ 639.4

Royalties. Royalties increased by $51.7 million to $132.7 million for the year ended December 31, 2001, as a consequence of the increase in production revenue. The royalty rate before hedging for the year ended December 31, 2001, decreased to 22.5% from 23.0% for the year 2000.

Operating Expenses. Operating expenses increased to $120.1 million for the year ended December 31, 2001 from $55.0 million in 2000, due mainly to the higher production volumes associated with acquisition activities. This represents a cost of $6.09/Boe in 2001 compared to $4.83/Boe in 2000. Increased activity levels in the industry during the first nine months of 2001 created a higher demand for goods and services that put upward pressure on costs. In addition, we experienced higher electricity costs in the first half of 2001 compared to 2000. Finally, the acquisition of properties during 2000 and 2001 with relatively higher operating costs than the pre-existing property portfolio added to our operating cost per Boe.

General and Administrative Expenses. General and administrative expenses increased $5.8 million to $13.0 million for the year ended December 31, 2001, compared to $7.2 million for the year 2000. The increase reflects the additional costs of managing acquired entities. General and administrative costs per Boe of production increased marginally to $0.66/Boe for 2001 compared to $0.63/Boe for 2000.

In accordance with the full cost method of accounting, we capitalized $7.5 million of general and administrative expenses in 2001 compared to $7.9 million capitalized in 2000. The majority of these capitalized costs represent compensation costs for staff involved in development drilling and acquisition activities.

Management Fees. Management services are supplied to us on a fee and cost reimbursement basis. Management fees expensed were $9.3 million for the year ended December 31, 2001, which represents an increase of $4.8 million over the year 2000. These increased fees are a result of higher operating income as well as the increase in the base management fee percentage, as discussed below, relative to the restructuring of management fees in their entirety.

In conjunction with the reverse take-over of Enerplus, a new management agreement was approved by the unitholders on June 21, 2001. Under the new agreement, base management fees were set at 2.75% of net operating income (compared to pre-June 21, 2001 rates of 2.2% for EnerMark Income Fund and 3.5% for Enerplus). In addition, acquisition and divestment fees, which were capitalized for financial statement purposes, were eliminated and were replaced by performance fees based on both our total return and our relative performance as compared to certain other conventional oil and gas trusts. The performance fee can range between 0% and 4% of operating income. In connection with the merger, the management company was paid a fee of 172,500 Enerplus trust units with a value of $5 million in 2001, which was capitalized as part of the merger cost. The management fee is described in "Management and Corporate Governance Management Agreement," as well as Note 6 to our audited annual consolidated financial statements.

Interest Expense. Interest expense for the year 2001 was $17.6 million, up $2.3 million from 2000 due to higher outstanding bank debt incurred in connection with the acquisition activities in 2000 and 2001. Bank debt increased to $412.6 million at December 31, 2001 from $275.9 million on December 31, 2000. During 2001, our interest costs were entirely based on floating rates.

Depletion, Depreciation and Amortization. Depletion, depreciation and amortization increased to $194.1 million in 2001 from $80.3 million in 2000. Included in the amortization amount are $7.1 million of amortized costs relating to the mark-to-market value of our commodity price forward contracts at the time of the reverse takeover. The mark-to-market value of these contracts was recognized as either a deferred hedge asset or liability as part of the acquisition cost and will be amortized over the remaining term of the contract ending in 2004. The actual gain (or loss) associated with this contract will be recognized in oil and gas sales as they are realized.

	2001	2000
	(in millions)	
Depletion and depreciation	$ 181.1	$ 76.5
Amortization of future site restoration	5.9	3.8
Amortization of deferred hedging costs	7.1	
Total	$ 194.1	$ 80.3

The rate of depletion and depreciation increased to $9.18/Boe in 2001 from $6.72/Boe in 2000. The increase was the result of higher costs attributed to petroleum and natural gas assets acquired during 2000 and 2001. The adoption of the liability method of accounting for future income taxes, as required by Canadian GAAP, had the effect of substantially increasing the recorded value of acquired property, plant and equipment compared to the previous deferral method of accounting. In the case of the corporate acquisitions in 2000, the value of acquired assets were increased to reflect any shortfall between the net book value and the cost basis for income tax purposes.

Taxes. Capital taxes increased to $4.7 million for the year 2001 from $2.9 million in 2000 primarily due to the increase in capital structure.

For the year ended December 31, 2001, a future income tax recovery of $31.5 million was recorded in income. Under Canadian GAAP, the Fund does not recognize any future income taxes, as taxable income is distributed to unitholders in the form of taxable distributions. However, our Operating Companies are required to account for future income taxes. Future income taxes arise because of the difference between the accounting and tax basis of the Operating Companies' assets and liabilities.

Netbacks. The following table illustrates our netbacks per Boe of production.

	Year Ended December 31,	
	2001	2000

	Year Ended December 31,	
Oil and gas sales	$ 32.43	$ 30.14
Royalties	(6.73)	(7.10)
Operating expenses	(6.09)	(4.83)
General and administrative expenses	(0.66)	(0.63)
Management fees	(0.47)	(0.40)
Interest expense, net of interest and other income	(0.85)	(1.30)
Capital taxes	(0.24)	(0.26)
Restoration and abandonment cash costs	(0.13)	(0.13)
Funds flow from operations	17.26	15.49
Depletion and depreciation	(9.18)	(6.72)
Amortization, net of cash costs	(0.54)	(0.21)
Future income tax recovery (provision)	1.60	(1.35)
Net income per Boe of production	$ 9.14	$ 7.21

As illustrated in the chart above, we earned net income of $9.14 for every Boe produced in 2001. This netback per Boe realized in 2001 is $1.93 per Boe more than 2000.

Net Income and Funds Flow From Operations. Net income for the year ended December 31, 2001 was $180.3 million, up 119% from $82.2 million for the year 2000. On a per unit basis, net income increased 7% to $3.28 per trust unit in 2001 from $3.06 per trust unit in 2000. After adding back non-cash expenses such as depletion, depreciation, amortization and the future income tax provision (recovery), the resultant funds flow from operations was $340.2 million in 2001 or $6.20 per trust unit compared to $176.4 million or $6.57 per trust unit in 2000.

Liquidity and Capital Resources

We anticipate that we will continue to have adequate liquidity to fund future recurring operating expenses and planned capital expenditures for 2003. Our primary cash requirements consist of normal operating expenses, capital expenditures, debt service payments, distributions to our unitholders and acquisitions of new properties. Short-term cash requirements, such as operating expenses and monthly distributions to unitholders, are funded with operating cash flows. Long-term cash requirements for acquisitions are funded by several sources, including borrowings under bank credit facilities and the issuance of additional debt and equity securities, including trust units. We have typically funded our acquisitions through either borrowings under our credit facility or the direct issuance of trust units. These borrowings are ultimately repaid from the issuance of additional trust units or from internally generated cash flows. Our ability to complete future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates and our financial condition at the time.

At March 1, 2002, we renegotiated our bank facilities and consolidated the bank lines of the former EnerMark and Enerplus operating companies. As at September 30, 2002, we had a $620 million borrowing base limit with respect to our unsecured credit facilities and senior unsecured notes as follows:

Senior unsecured notes	$ 268.3 million
Revolving bank facility	322.0 million
Demand bank facility	29.7 million
Total borrowing base	$ 620.0 million

The revolving bank facility is syndicated with seven banks. It is a committed 364 day facility with an incremental amortizing two year term. In the event that the revolving bank line is not extended at the end of the 364 day revolving period, no payments are required to be made to non-extending lenders during the first year of the term period. However, we will be required to maintain certain minimum balances on deposit with the syndicate agent.

On November 7, 2002, we increased our borrowing base by $80 million to $700 million, resulting in an increase in our revolving bank facility from $322 million to $402 million. Our bank credit facilities have no financial covenants, but contain cross defaults to our senior notes. Our borrowing base is based on the banks' evaluation of the value of our proved oil and natural gas reserves. The banks have reserved the right to revise the commitment based on a review of the year end reserve information. The bank debt has priority over claims of and distributions to our unitholders. However, unitholders have no direct liability with respect to the bank loan should revenues be insufficient to repay it.

During the second quarter of 2002, we diversified our debt portfolio through the issuance by EnerMark of US$175 million senior, unsecured notes with a coupon rate of 6.62% priced at par. The senior 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. These senior notes require us, among other things, to (1) maintain an interest coverage ratio (EBITDA to interest expense for the four preceding quarters) of at least 4.0 to 1.0, (2) maintain a ratio of debt to present value of proved reserves of not more than 0.6 to 1.0, and (3) with certain exceptions, maintain a ratio of debt to EBITDA of not more than 3.0 to 1.0. The senior notes also impose restrictions on EnerMark's ability to incur debt, grant liens and make payments, including royalty and dividend payments to the Fund, in circumstances of default. They also impose restrictions on asset divestitures, mergers and consolidations. We are currently in compliance with all such requirements. The Fund and ERC have subordinated their rights to receive from EnerMark and, in the case of the Fund, from ERC, payments of debt and interest accrued thereon and royalty payments to the prior payment in full in cash of the senior notes. Concurrent with the issuance of the senior notes, we swapped the US$175 million into Canadian dollar denominated floating rate debt at an exchange rate of Cdn$1.5333/US$ for gross proceeds of $268.3 million at a floating interest rate, based on Canadian three month banker's acceptances, plus 1.18%. The mark-to-market value of the cross-currency interest rate swap at September 30, 2002 was an in-the-money gain of $40 million.

On September 12, 2002, we closed an equity offering of 4,750,000 trust units at a price of $26.85 per trust unit for gross proceeds of $127,538,000 (net $120,886,000). These proceeds were used to reduce the amounts outstanding on the bank credit facilities.

Our long-term debt as at September 30, 2002 was $362.5 million, which was comprised of bank credit facilities of $94.2 million and senior unsecured notes of $268.3 million. This was lower than long-term debt of $412.6 million as at December 31, 2001. The decrease in debt can be attributed to the equity issue on September 12, 2002 combined with cash from operations that has been withheld for debt repayments.

On August 8, 2002, we assumed approximately $4.1 million in contingent project debt in connection with our acquisition of a working interest in the Joslyn Creek Lease. This contingent project debt was comprised of $3,360,000 of principal and approximately $740,000 in accrued interest. Interest is accrued at the Bank of Canada prime business rate and is not compounded. The debt is contingent on both production and pricing hurdles with respect to development on the lease. As it is too early in the development of this project to determine if these hurdles will be satisfied, the contingent debt has not been accrued in our financial statements.

Our financial leverage and coverage ratios for the nine months ended September 30, 2002 and the year ended December 31, 2001, were as follows:

	Nine Months Ended September 30, 2002	**Year Ended December 31, 2001**
Long-term debt to funds flow from operations[1]	1.3x	1.2x
Funds flow from operations to interest expense[1]	16.4x	19.3x
Long-term debt to long-term debt plus equity	21%	23%

(1) Funds flow from operations and interest expense is based on the first nine months of 2002 plus the last three months of 2001.

On October 21, 2002, we acquired all of the outstanding shares and retired the debt of Celsius Energy Resources Ltd., a private oil and gas producer in Calgary, Alberta, for a total consideration of $165.9 million, including working capital adjustments. This acquisition was funded with borrowings of $165.9 million under our credit facility. We will repay these borrowings with a portion of the net proceeds of this offering.

During the nine months ended September 30, 2002, we spent $101.0 million on capital expenditures prior to acquisitions and divestitures. During this same time period, we spent $45.9 million on acquisitions of oil and gas properties, net of dispositions. Through the remainder of the year, we will continue to pursue acquisition opportunities while maintaining a focused effort on the development of existing reserves.

We pay monthly distributions to our unitholders. The amount available to us to pay distributions depends on the level of monthly net cash flow received by us from EnerMark and ERC pursuant to the royalty agreements, as well as from other sources such as interest, principal and dividend payments received from EnerMark and, indirectly, ERC. The board of directors of EnerMark regularly evaluates our distribution payout with respect to forecast cash flows, debt levels and spending plans. Please read "Distributions" for more information on these distributions.

Natural Gas Pipeline Commitments

We have contracted to transport 10 MMcf/day of natural gas into Chicago on the Foothills and Northern Border pipelines until October 31, 2008. We have also agreed to transport 5 MMcf/day to Marshfield, Illinois on the TransCanada and Viking pipelines until October 31, 2008. In addition, we have pipeline commitments to transport 5 MMcf/day into Chicago on Alliance Pipeline until October 31, 2015.

Trust Unit Information

We had 69,532,000 trust units and no warrants outstanding at December 31, 2001 compared to 40,925,000 trust units and 3,045,000 warrants at December 31, 2000. The weighted number of trust units outstanding during 2001 and 2000 was 54,907,000 and 26,841,000, respectively.

During 2001, we issued 20,863,000 additional trust units pursuant to the merger agreement on June 21, 2001. In addition, 1,267,000 trust units were issued to acquire the non-controlling interest with respect to the Cabre acquisition, and 4,312,500 trust units were issued pursuant to the November 15, 2001 equity offering. We also issued 3,045,000 warrants on December 31, 2000 and an additional 390,000 warrants on January 8, 2001 pursuant to the Cabre acquisition, of which 1,197,000 were exercised during 2001 and 2,238,000 expired on December 17, 2001. On September 12, 2002, we closed an equity offering of 4,750,000 trust units.

As at September 30, 2002, Enerplus had 74,751,000 trust units and no warrants outstanding. The weighted average number of trust units outstanding during the nine months ended September 30, 2002 was 70,066,000 (2001 50,738,000).

Risk Management Strategy

We are exposed to a variety of market risks, including changes in commodity prices, foreign currency exchange rates and interest rates. As part of our business strategy, we manage commodity price risk, when appropriate, through hedging agreements that will increase the level of predictability in prices for our oil and gas production. We do not currently hedge against foreign currency risks, with the exception of the cross-currency swap associated with the senior unsecured notes. We engage in certain interest rate swaps to manage our interest rate risks. Derivative financial instruments involve a degree of credit risk, which we endeavour to control through the use of financially sound counterparties. Please read "Business Risk Management" for more information on these strategies.

We have continued to implement hedging transactions in accordance with our commodity price risk management program during the third quarter. The program is intended to provide a measure of stability to our cash distributions as well as to ensure that we realize positive economic returns from our capital development and acquisition activities.

Our commodity risk management position as at September 30, 2002 is described in Note 5 to our interim unaudited consolidated comparative financial statements included in this prospectus. Commodity price risk is managed through fixed price physical delivery contracts and financial instruments such as forward contracts. The net receipts or payments arising from the forward contracts are recognized in income as a component of oil and gas sales during the same period as the corresponding hedge position. At September 30, 2002, we had $1.9 million in deferred costs related to forward contracts that will be amortized over the remaining life of those instruments. The mark-to-market value of the financial forward contracts represented an unrealized loss of $27.0 million with reference to quarter-end prices and forward markets. As of September 30, 2002, we had the following physical and financial contracts in place with respect to crude oil and natural gas prices:

Physical and Financial Commodity Price Contracts

Contracted Period	Natural Gas Contracted Volumes (MMcf/day)	Natural Gas % of Estimated Gross Production[(1)]	Crude Oil Contracted Volumes (Bbls/day)	Crude Oil % of Estimated Gross Production[(1)]
Remainder of 2002	66.0	29%	11,175	45%
2003	75.0	33	11,000	44
2004	35.0	15	4,750	19

(1) Production volumes are measured with reference to year-to-date production adjusted for the Celsius acquisition.

Sensitivity Analysis

Even with the commodity price contracts described above in place, our cash flow remains sensitive to changes in commodity prices as demonstrated by the following table:

	Sensitivity to Changes in Price and Exchange Rate and Effect on 2003 Distributions per Trust Unit
Change of Cdn$0.10 per Mcf in the price of natural gas	$ 0.07
Change of US$1.00 per Bbl in the price of WTI crude oil	0.15
Change of 1,000 Boe/day in production	0.09
Change of $0.01 in the US$/Cdn$ exchange rate	0.06
Change of 1% in interest rate	0.07

These sensitivities are based on our current projections of 2003, which have been adjusted to include all commodity contracts as described in Note 5 to our interim unaudited consolidated comparative financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001. These sensitivities apply to commodity prices, production and exchange rates within the context of current market rates and our current risk management positions. To the extent the market price of crude oil or natural gas change to levels that are above the ceiling or below the floor price limits set by our existing commodity contracts, the above sensitivities will no longer be relevant. Because these sensitivities assume a number of factors, actual sensitivities may vary materially from what is presented.

In the future, we intend to continue to manage our commodity price exposure in a similar manner. The future gain or loss from such a program depends on forward markets and future prices. The significant hedging gains experienced in 2001 are not expected to be replicated in 2002.

Significant Accounting Policies

Our management prepares our financial statements following Canadian GAAP. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The following is a summary of our significant accounting policies. For a complete description of our accounting policies, please read Note 1 to our interim unaudited consolidated comparative financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001 and Note 2 to our audited consolidated financial statements as at and for the years ended December 31, 2001 and 2000 included in this prospectus.

Oil and Natural Gas

We follow the full cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against earnings, and renewals and enhancements which extend the recoverable reserves of the property, plant and equipment area capitalized. During 2001 and the first nine months of 2002, general and administrative costs of $7,547,000 and $6,100,000 respectively, were capitalized.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would significantly alter the rate of depletion.

Ceiling Test

We place a limit, referred to as the "ceiling test," on the aggregate cost of property, plant and equipment, which may be carried forward for amortization against revenues of future periods. The ceiling test is a cost recovery test whereby the capitalized costs less accumulated depletion and depreciation, accumulated site restoration and future income taxes are limited to an amount equal to estimated undiscounted future net revenues from proved reserves, plus the unimpaired costs of non-producing properties, less estimated future general and administrative expenses, site restoration costs, management fees, financing costs and capital taxes. Costs and prices at the balance sheet date are used in determining ceiling test amounts. Any costs carried on the balance sheet in excess of the ceiling test limitation are charged to earnings.

Depletion and Depreciation

The provision for depletion and depreciation of oil and natural gas assets is calculated using the unit-of-production method based on our share of estimated proved reserves before royalties. Reserves are converted to equivalent units on the basis of approximate relative energy content based on our share of estimated proved reserves before royalties.

Change in Accounting Policy

Effective January 1, 2000 we, on a retroactive basis, adopted the liability method of accounting for income taxes in accordance with the new Canadian Institute of Chartered Accountants income tax standard. The cumulative effect as at January 1, 2000 was to increase future income taxes payable and decrease accumulated income by $16,177,000. The 1999 financial statements have not been restated for the change. The new recommendations do not affect our cash flow or liquidity.

Certain Accounting Differences Under U.S. GAAP

The following is a summary of certain differences in accounting for the ceiling test, derivative instruments and stock-based compensation under U.S. GAAP. There are further differences between U.S. GAAP and Canadian GAAP that apply to us. These are discussed in Note 8 to our unaudited interim consolidated financial statements for the three and nine months ended September 30, 2002 and 2001 and Note 10 to our audited consolidated financial statements for the year ended December 31, 2001 included in this prospectus.

Ceiling Test

Under U.S. GAAP, for Securities and Exchange Commission registrants following full cost accounting, the carrying value of petroleum and natural gas properties and related facilities, net of deferred income taxes, is limited to the present value of after tax future net revenue from proved reserves, discounted at 10 percent (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproved properties. Under Canadian GAAP, the ceiling test is calculated without application of a discount factor, but includes general and administration, management fees and interest expense.

Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion, depreciation, and amortization will differ in subsequent years. As at September 30, 2001, the application of the ceiling test under U.S. GAAP resulted in a write-down of $744.3 million ($458.4 million after tax) of capitalized costs. At December 31, 2000 and as September 30, 2002, the application of the ceiling test under U.S. GAAP did not result in a write-down of capitalized costs. Under Canadian GAAP, the application of the ceiling test did not result in a write-down for the years 2001 and 2000 and for the nine months ended September 30, 2001 and September 30, 2002.

Accounting for Derivatives

Effective January 1, 2001, for U.S. reporting purposes, we adopted Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes accounting and reporting standards requiring that all derivative instruments (including derivative instruments embedded in other contracts), as defined, be recorded in the balance sheet as either an asset or a liability measured at fair value and requires that changes in fair value be recognized currently in income unless specific hedge accounting criteria are met. There are no similar standards under Canadian GAAP.

Hedge accounting treatment allows unrealized gains and losses to be deferred in other comprehensive income (for the effective portion of the hedge) until such time as the forecasted transaction occurs and requires that an entity formally document, designate and assess the effectiveness of derivative instruments that receive hedge accounting treatment. Upon adoption, we formally documented and designated all hedging relationships and verified that its hedging instruments are effective in offsetting changes in actual prices received by Enerplus. Such effectiveness is monitored at least quarterly and any ineffectiveness is reported in other revenues (losses) in the consolidated statement of operations.

Accounting for Stock-Based Compensation

Under Canadian GAAP, compensation expense is not recognized for options granted to or exercised by employees, directors and consultants of Enerplus under its Trust Unit Option Plan (the "Unit Plan") and the new Trust Unit Rights Incentive Plan (the "Rights Plan"). For U.S. GAAP purposes, we use the intrinsic value method of accounting for options and rights issued to its employees, directors and consultants who meet the definition of an employee under U.S. GAAP. Under the Unit Plan, as the exercise price of the options was equal to the market price of the trust units on the grant date, no compensation expense has been recorded for U.S. GAAP purposes. The Rights Plan is a variable compensation plan as the exercise price of the rights is subject to downward revisions from time to time. Accordingly, compensation expense is determined as the excess of the market price of the trust units over the exercise price of the rights at each financial reporting date and is deferred and recognized in income over the vesting period of the rights. After the rights have vested, compensation expense is recognized in income in the period in which a change in the market price of trust units or the exercise price of the rights occurs.

Recent Developments in U.S. Accounting Standards

In July 2001, the Financial Accounting Standards Board ("FASB") issued SFAS 141, "Business Combinations" and SFAS 142, "Goodwill and Other Intangible Assets." SFAS 141 requires the purchase method of accounting to be used for all business combinations initiated after June 30, 2001. SFAS 142 requires that goodwill and intangible assets with an indefinite useful life no longer be amortized, but instead tested for impairment at least annually. SFAS 142 is effective for fiscal years beginning after December 15, 2001, except that goodwill and intangible assets acquired after June 30, 2001 will be subject immediately to the amortization and non-amortization provisions of SFAS 142. At this time, the adoption of SFAS 141 and SFAS 142 have no impact on our financial statements.

In June 2001, FASB issued SFAS 143, "Accounting for Asset Retirement Obligations." SFAS 143 requires liability recognition for retirement obligations associated with tangible long-lived assets. The obligations included within the scope of SFAS 143 are those for which we face a legal obligation for settlement. The initial measurement of the asset retirement obligation is to be at fair value. The asset retirement cost equal to the fair value of the retirement obligation is to be capitalized as part of the cost of the related long-lived asset and amortized to expense over the useful life of the asset. SFAS 143 is effective for all fiscal years beginning after June 15, 2002. The total impact on our financial statements has not yet been determined.

BUSINESS

Who We Are

We are the largest conventional oil and gas trust in North America in terms of market capitalization, production volumes and oil and natural gas reserves. Our trust units are listed on the Toronto Stock Exchange and the New York Stock Exchange and our market capitalization as at November 25, 2002 was approximately $1.9 billion. Through our operating subsidiaries, we actively manage the acquisition and development of, and production from, oil and natural gas properties. Our operations are currently focused exclusively in western Canada.

We hold interests in a diversified and balanced portfolio of mature oil and natural gas properties. Our properties generally have predictable production profiles, long reserve lives, and the opportunity for development. Approximately 55% of our production and reserves is comprised of natural gas and approximately 45% is comprised of crude oil and natural gas liquids, or NGLs. As of January 1, 2002, we had established reserves of 312 MMBoe and net proved reserves of 215 MMBoe. The established reserve life index and the R/P ratio of our properties as of January 1, 2002 was 14.0 years and 9.4 years, respectively.

Our primary purpose is to generate and distribute cash flows to unitholders. As such, we focus on the acquisition and lower-risk development of mature, long-life oil and natural gas properties. We do not participate in exploration activity because of the higher risks involved. Our production is typically more predictable and stable than traditional exploration and production, or E&P, companies and our operations are generally not as capital intensive.

We make monthly cash distributions to our unitholders from the net cash flows that we receive from our oil and gas operations. The amount of that net cash flow is subject to many factors, including fluctuations in the quantity of oil and natural gas that we produce, the prices we receive for that production and the operating costs associated with that production. Our cash distribution for November 2002 was $0.30 (US$0.19) per trust unit, and we have paid cumulative distributions of $3.40 (US$2.16) per trust unit in the twelve months through and including October 2002.

Since its inception, Enerplus Resources Fund has grown significantly through a series of mergers and acquisitions, the most significant of which was the merger of Enerplus Resources Fund and EnerMark Income Fund on June 21, 2001. During that time, we, including pre-merger Enerplus, have increased our average daily production volumes from 34 Boe/day for the twelve months ended November 30, 1986 to 61,493 Boe/day for the nine months ended September 30, 2002.

For Canadian income tax purposes, we are classified as a "mutual fund trust." For United States federal income tax purposes, we are considered a corporation and are not a partnership or a master limited partnership (or MLP). You should read the information in "Certain Income Tax Considerations" and consult your own tax advisors to find out more about the tax consequences of owning trust units.

Our Business Strategy

Our objective is to maximize our net cash flows, and therefore the distributions to our unitholders, while minimizing the risk associated with these cash flows, optimizing the economic recovery from our properties and assets and maintaining a prudent capital structure. To accomplish these goals, our business strategy is to:

- continue to develop our existing properties to maintain and enhance oil and natural gas production;
- acquire suitable energy-related properties and assets such as mature, long-life oil and natural gas properties with predictable production profiles;
- maintain a balanced portfolio of geographically and geologically diversified oil and natural gas properties;
- control costs through the efficient operation of existing and acquired properties;
- manage commodity price risk, when appropriate, through hedging agreements; and
- employ financial and corporate policies that facilitate access to capital.

Our Organizational Structure

Our trust structure provides us with an efficient means to distribute our net cash flows to our unitholders. Our structure increases the amount of cash distributions available to our unitholders as cash flows have historically flowed from the Operating Companies to the Fund with little or no corporate income tax payable at the Operating Company level. As the Fund distributes all of its taxable income to its unitholders, no income taxes are paid at the Fund level.

The Fund's primary sources of net cash flow are (1) payments received from 95% and 99% net royalty interests granted to the Fund by EnerMark and ERC, respectively, on the production from their oil and natural gas properties, (2) interest and principal payments on debt issued to the Fund by EnerMark, and (3) dividend payments received by the Fund from EnerMark and, indirectly, from ERC.

Enerplus Resources Fund

Enerplus Resources Fund is a publicly traded open-ended investment trust whose principal undertaking is to issue trust units to the public and to indirectly invest its funds in oil and natural gas properties and other energy-related assets. The Fund's investment in these oil and natural gas interests is held entirely through its Operating Companies. Each trust unit represents an equal, undivided beneficial interest in the Fund. The Fund pays cash distributions to its unitholders from the net cash flow received from the Operating Companies. The Fund is managed by EGEM pursuant to a management agreement. The Fund is governed by the laws of the Province of Alberta. Its head and principal office is located at The Dome Tower, Suite 3000, 333 - 7th Avenue S.W., Calgary, Alberta, Canada T2P 2Z1.

EnerMark Inc. and Enerplus Resources Corporation

EnerMark and ERC own and operate our oil and gas properties on behalf of the Fund. Both EnerMark and ERC are corporations organized under the *Business Corporations Act* (Alberta). All of the issued and outstanding shares of EnerMark are owned by the Fund, and all of the issued and outstanding shares of ERC are owned by EnerMark. EnerMark and ERC are managed by EGEM pursuant to a management agreement. The head, principal and registered office of each of EnerMark and ERC is located at The Dome Tower, Suite 3000, 333 - 7th Avenue S.W., Calgary, Alberta, Canada T2P 2Z1.

Enerplus Global Energy Management Company

EGEM manages the Fund and the Operating Companies pursuant to a management agreement. EGEM is a corporation organized under the *Companies Act* (Nova Scotia) and is an indirect wholly-owned subsidiary of El Paso Corporation of Houston, Texas. The board of directors of EnerMark, which oversees the business and affairs of Enerplus, has retained EGEM to provide comprehensive management services and to administer and regulate the day-to-day operations and make executive decisions in respect of Enerplus that conform to general policies and principles established by the board of directors of EnerMark. For these services, EGEM receives a management fee, incentive fees based on the performance of the Fund and reimbursement of its general and administrative expenses. Please read "Management and Corporate Governance." The head and principal office of EGEM is located at The Dome Tower, Suite 3000, 333 - 7th Avenue S.W., Calgary, Alberta, Canada T2P 2Z1.

Governance of Enerplus

EnerMark's board of directors is responsible for the overall governance of Enerplus and establishes the general policies and principles outlining the overall management and direction of Enerplus, including the supervision of EGEM. The board of directors must be comprised of a minimum of seven directors, three of which are nominated by EGEM pursuant to the governance agreement. The remainder of the board is nominated by the unitholders. Currently there are eight directors of EnerMark, a majority of which are independent, including the Chairman of the board of directors. The board of directors is responsible for the annual renewal, for continuous three year terms, of the management agreement pursuant to which EGEM is engaged, with the current term expiring on June 30, 2005. For further details, please read "Management and Corporate Governance."

Historical Development

Enerplus Resources Fund was formed in 1986 and was the first Canadian oil and gas trust to list its trust units on the Toronto Stock Exchange and, in November 2000, on the New York Stock Exchange. We, together with our predecessors, have grown production and reserves over our 16 year operating history through acquisitions and the development and exploitation of existing reserves. Since its inception, Enerplus Resources Fund, including pre-merger Enerplus, has increased its average daily gross production volumes from 34 Boe/day for the twelve months ended November 30, 1986 to 61,493 Boe/day for the nine months ended September 30, 2002.

Enerplus has grown significantly in recent years through a series of transactions, including the consolidation of many of the entities within the Enerplus Group, such as EnerMark Income Fund, Westrock Energy Income Fund I, Westrock Energy Income Fund II and Enerplus Pension Resource Corporation III. The most significant of these was the merger of Enerplus Resources Fund and EnerMark Income Fund on June 21, 2001 to form the largest conventional oil and gas trust in North America. Subsidiaries of EGEM managed each of Enerplus and EnerMark Income Fund at the time of the merger.

EnerMark Income Fund was formed in 1996 through the corporate reorganization of Mark Resources Inc. Prior to its merger with Enerplus, EnerMark Income Fund completed several significant acquisitions, including the acquisitions of Western Star Exploration Ltd., Pursuit Resources Corp., EBOC Energy Ltd. and Cabre Exploration Ltd., as well as the acquisition of property interests in the Hanna/Garden Plains area of Alberta.

The following tables summarize recent material acquisitions by Enerplus Resources Fund (including pre-merger Enerplus) and EnerMark Income Fund.

Enerplus Resources Fund

Acquisition	Closing Date	Cost[1]	Established Reserves[2]	Production[2]
		(in millions)	(MBoe)	(Boe/day)
Celsius Energy Resources Ltd.	October 21, 2002	$ 166	17,997	5,750
Kaybob property	September 26, 2001	25	2,102	1,177
Enerplus Pension Resources Corporation III	December 19, 2000	110	24,031	3,217
Westrock Energy Income Fund I[3]	June 8, 2000	60	19,154	2,836
Westrock Energy Income Fund II[3]	June 8, 2000	80	22,913	4,050
Pembina Five-Way property	April 20, 2000/ November 15, 2000	18	4,575	413

EnerMark Income Fund

Acquisition	Closing Date	Cost[1]	Established Reserves[2]	Production[2]
		(in millions)	(MBoe)	(Boe/day)
Cabre Exploration Ltd.	December 21, 2000	$ 311	40,469	14,200
EBOC Energy Ltd.	September 1, 2000	155	29,794	6,425
Pursuit Resources Corp.	April 3, 2000	119	22,067	5,532
Hanna/Garden Plains property	February 28, 2000	34	17,191	1,500
Western Star Exploration Ltd.	January 7, 2000	27	7,135	1,256

(1) Acquisition cost includes consideration paid, debt assumed and transaction and related costs and charges.

(2) Based on Enerplus' and EnerMark Income Fund's, as the case may be, estimates of established reserves and gross average daily production at the time of the acquisition.

(3) Enerplus Resources Fund merged with Westrock Energy Income Fund I and Westrock Energy Income Fund II on June 8, 2000. Enerplus issued approximately 3,344,329 trust units to former unitholders of Westrock Energy Income Fund I and 5,310,733 trust units to former unitholders of Westrock Energy Income Fund II. The book carrying value of unitholders' equity is deemed to be the consideration paid.

Acquisition and Development Activities

Since we do not engage in exploration activities, we rely primarily upon acquisitions to both replenish and add to our oil and natural gas reserves. In pursuing acquisitions, we employ a focused and disciplined strategy to ensure that the reserves being considered are a strategic fit with our existing portfolio of properties. We have typically funded our acquisitions through either borrowings from our existing credit facility or the direct issuance of trust units. Borrowings are subsequently repaid through the issuance of additional trust units or from internally-generated cash flows. This strategy provides us with the flexibility to respond to acquisition opportunities.

A common strategy of E&P companies is to divest mature properties in order to redeploy capital into higher-risk exploration. Because of our focus on exploiting mature properties, we provide them with a ready, accessible market for those divestitures. To the extent that our acquisitions include undeveloped properties, we enter into farmout or swap agreements under which an E&P company will explore and drill the undeveloped properties on our behalf, generally at no cost to us, in exchange for a portion of our interests in the property. Additionally, our size facilitates our ability to make relatively large acquisitions as compared to many of our competitors. Finally, the tax effectiveness of our trust structure allows us to bid competitively for oil and natural gas properties against less tax-efficient entities.

We undertake lower-risk development activities to mitigate declines in total production, upgrade our reserves and extend the useful lives of many of our properties. Development activities are particularly important to us during periods when there are a limited number of attractive acquisition opportunities. Our development activities provide a lower-risk, less capital intensive alternative for increasing production volumes than do traditional exploration activities. Our development activities are typically funded through debt which is subsequently repaid through issuances of trust units and internally-generated cash flow.

Our Properties

Substantially all of our oil and natural gas properties are located in western Canada in the provinces of Alberta, British Columbia and Saskatchewan. As of January 1, 2002, we had established reserves of 132 MMBbls of crude oil and NGLs and 1,082 Bcf of natural gas, for a total of 312 MMBoe, and net proved reserves of 91 MMBbls of crude oil and NGLs and 745 Bcf of natural gas, for a total of 215 MMBoe. For the nine month period ended September 30, 2002, our properties produced, on a barrel of oil equivalent basis, approximately 55% natural gas, 38% crude oil and 7% NGLs. The gross average daily production from our properties for the nine months ended September 30, 2002 was 204,463 Mcf/day of natural gas and 27,416 Bbls/day of crude oil and NGLs, for a total of 61,493 Boe/day.

The following table shows our principal properties by region, together with the gross average daily production for the nine months ended September 30, 2002 attributable to our interests in each property.

	Gross Average Daily Production for the Nine Months Ended September 30, 2002			
	Oil and NGLs	**Natural Gas**	**Total**	**% of Total Production**
	(Bbls/day)	**(Mcf/day)**	**(Boe/day)**	**(%)**
Principal Properties:				
North West Region				
Deep Basin	631	11,219	2,501	4.1%
Valhalla	762	8,610	2,197	3.6
Progress	759	5,527	1,680	2.7
Cranberry	68	3,060	578	0.9
Central Region				
Joarcam	2,194	5,743	3,151	5.1
Pembina 5 Way/South Buck Lake	2,395	1,592	2,660	4.3
Kaybob	344	4,953	1,170	1.9
Pine Creek	224	4,522	978	1.6
Willesden Green	208	2,748	666	1.1
East Central Region				
Giltedge	1,635	416	1,704	2.8
Gleneath	1,038	390	1,103	1.8
Auburndale	559	573	655	1.1
Hayter	676	14	678	1.1
Kessler	576	101	593	1.0
Cadogan	442		442	0.7
David	372	58	382	0.6

	Gross Average Daily Production for the Nine Months Ended September 30, 2002			
South Central Region				
Hanna/Garden Plains	2	12,500	2,085	3.4
Benjamin	13	12,425	2,084	3.4
Sylvan Lake	689	3,556	1,282	2.1
Ferrier	240	4,738	1,030	1.7
Bashaw	16	3,491	598	1.0
Harmattan	221	1,257	431	0.7
South East Region				
Medicine Hat Region	7	35,690	5,955	9.7
Medicine Hat Glauconite "C"	1,152	1,248	1,360	2.2
Jenner	394	1,883	708	1.2
Other	11,799	78,149	24,822	40.2
Total	27,416	204,463	61,493	100.0%

We actively manage our portfolio of oil and natural gas properties through our acquisition, divestiture and development activities. Our properties generally have the following characteristics:

Long-life properties with predictable production profiles. The majority of our properties have predictable production profiles and are relatively long-life properties. This facilitates our ability to generate relatively stable and predictable production from our properties. As of January 1, 2002, the established reserve life index and R/P ratio of our properties was 14.0 years and 9.4 years, respectively.

Diversified and balanced portfolio of assets with focus on core areas. Our portfolio of properties is both diversified, from a geographical and geological perspective, and well balanced between liquids and natural gas. Our properties are located throughout the Western Canadian Sedimentary Basin and access both shallow and deep producing horizons. For the nine months ended September 30, 2002, production from our properties was approximately 55% natural gas and 45% crude oil and NGLs, on a Boe basis. We are not dependent on any single property for a significant portion of our production as no single property currently represents more than 10% of our total production. Notwithstanding this diversity, our top 25 principal properties currently represent approximately 60% of our total production. Our focus on these core areas increases the efficiency of our operations and generally allows us to reduce operating costs, develop a strong understanding of the characteristics of these properties and continue to expand in these areas as we identify favourable opportunities.

Substantial development opportunities. We have identified development opportunities to mitigate declines in production, upgrade our reserves and extend the useful lives of many of our properties. We believe that these opportunities will allow us to add to our production at costs that are typically lower than through acquisitions. Our development activities have historically been relatively low-risk. In 2001, we participated in the drilling of 321.6 net development wells with a 99% success rate. For the nine months ended September 30, 2002, we participated in the drilling of 181.0 net development wells with a 99% success rate.

High level of operatorship. As at September 30, 2002, we operated properties comprising approximately 65% of our production. By operating our properties, we are better able to control both the operating costs and the optimization of recovery from our reserves.

Outlined below is a description of the general characteristics of each of our five operating regions:

North West Region

Located along the northern border of British Columbia and Alberta, the North West Region offers exposure to production of both natural gas rich in NGLs and light crude oil. The key properties in this region include Valhalla, Progress, Cranberry, and the non-operated Deep Basin area, a significant natural gas and NGLs producing area encompassing the Elmworth, Karr, Wapiti, and South Wapiti fields. Our production from this region is weighted to natural gas 68% on a Boe basis for the first nine months of 2002. The development potential in the Deep Basin, Valhalla and Progress natural gas properties, as well as the light oil pools at Valhalla and Progress, are a focus of our capital expenditures program. Over 21 MMBoe of our established reserves are attributable to the major properties in this region, representing approximately 7% of our total reserves as at January 1, 2002.

Central Region

The area surrounding the city of Edmonton, Alberta provides a variety of production bases, predominantly weighted to light quality sweet oil and liquids rich natural gas from long-life properties. For the nine months ended September 2002, our crude oil and NGLs production from this region represented 62% of the total Boe produced by us in this region. Our largest producing light oil properties are included in this region and generally they are all mature and have been under waterflood recovery techniques to optimize production for many years. Geological and reservoir engineering reviews to optimize the depletion of these oil pools have been recently undertaken. The major properties in this region consist of Pembina 5 Way/South Buck Lake, Pine Creek, Kaybob, Willesden Green and Joarcam, our largest crude oil producing

property, where we have drilled 14 infill wells during the year to date. As at January 1, 2002, over 60 MMBoe approximately 19% of our established reserves are contained in this region.

East Central Region

Located in an oil-producing belt along the Alberta/Saskatchewan border, the East Central Region reservoirs are primarily a compilation of light, medium and heavy oils. In the first nine months of 2002, our crude oil and NGLs production represented 95% of the total Boe that we produced from this region, including the majority of our heavy oil production. Properties belonging to this region include Giltedge, Auburndale, Hayter, Kessler, Cadogan, David, and Gleneath, a mature light sweet oil property where we have been active throughout this year employing a low-cost refracture stimulation technique to improve production. As at January 1, 2002 approximately 26 MMBoe of our established reserves are attributed to the major properties in this region, representing approximately 9% of our total established reserves.

South Central Region

Located just north of Calgary, Alberta, the production in this region is weighted to natural gas, accounting for 84% of the total Boe that we produced from this region for the nine months ended September 30, 2002. The South Central major properties include Hanna/Garden Plains, Benjamin, Sylvan Lake, Bashaw, Ferrier and Harmattan. Hanna/Garden Plains is a significant long-life shallow gas property being developed through large multi-well drilling programs that optimize the use of drilling and completion services to achieve capital efficiencies. There were 24 wells drilled during the second quarter of 2002 and 31 wells drilled in the third quarter of 2002 at this property. At another significant area, Benjamin, which is a non-operated, deep foothills natural gas property, we have participated in the drilling of three successful wells this year. Approximately 53 MMBoe of established reserves are attributable to the major properties in this region, which represents approximately 17% of our total established reserves as at January 1, 2002.

South East Region

Natural gas production in the South East Region is primarily comprised of shallow gas produced from four core properties Bantry, Fox Valley, Medicine Hat, and Verger which are collectively referred to as the Medicine Hat region and represents the largest portion of our natural gas production. The South East Region also includes heavy oil produced from the Glauconite reservoir produced primarily from the Medicine Hat Glauconite "C" property and from the non-operated Jenner property. On a Boe basis, for the first nine months of 2002, natural gas represented 81% of the Boe produced by us in this region. The shallow natural gas in this region is also developed using large multi-well drilling programs which deliver the economies of scale similar to the South Central Region. By the end of the third quarter of 2002, a 50 well development drilling program and a separate 30 well program were also completed. At the Medicine Hat Glauconite "C" property, a waterflood scheme was implemented in 2001 to enhance production and recoverable oil reserves. During the first quarter of 2002, an additional interest in this property was acquired for approximately $20.5 million. Over 55 MMBoe of established reserves are attributable to this long-life region as at January 1, 2002, representing approximately 18% of our total established reserves.

Selected Reserves Information

The following tables show selected oil and natural gas reserve data for Enerplus. The following information has been derived from the report prepared by Sproule Associates Limited with respect to our reserves as of January 1, 2002, which was the effective date of our last independent engineering report. Sproule is a large, established Canadian independent firm of petroleum engineers. **These tables should be read together with the information contained in "Appendix A Enerplus Reserves Information" and, in particular, the notes following the reserves tables contained in Appendix A, which include a description of certain assumptions made in preparing our reserve evaluation. Certain columns may not add due to rounding. For a description of certain terms used below and certain differences between estimating reserves under Canadian and U.S. reserve disclosure guidelines, please read "Presentation of Our Reserve Information" and "Glossary of Terms."**

The following tables, as well as the information contained in Appendix A, do not include the reserves of Celsius, which we acquired on October 21, 2002. Information regarding the reserves of Celsius is contained in "Appendix B Information Regarding Celsius Energy Resources Ltd."

Reserves as of January 1, 2002
Canadian Presentation
(Gross Reserves Using Escalated Prices and Costs)

					Estimated Future Net Cash Flow[(1)]	
	Crude Oil	Natural Gas Liquids	Natural Gas	Total	Undiscounted	Discounted at 10%
	(MBbls)	(MBbls)	(MMcf)	(MBoe)	(in thousands)	
Proved reserves:						
Developed producing	86,770	13,685	722,692	220,904	$ 2,992,588	$ 1,376,940
Developed non-producing	620	512	58,791	10,930	157,757	78,807
Undeveloped	7,457	1,917	169,650	37,649	401,713	170,532
Total proved reserves	94,847	16,114	951,133	269,483	3,552,058	1,626,279
Probable reserves (risked at 50%)	18,821	2,337	130,345	42,882	644,955	159,099
Established reserves	113,668	18,451	1,081,478	312,365	$ 4,197,013	$ 1,785,378

(1) The present value of estimated future net cash flow includes the Alberta Royalty Tax Credit and is stated before deduction of income tax. **Estimated future net cash flow is not to be construed as the fair market value of our reserves.**

Reserves as of January 1, 2002
Canadian Presentation
(Gross Reserves Using Constant Prices and Costs)

					Estimated Future Net Cash Flow[(1)]	
	Crude Oil	Natural Gas Liquids	Natural Gas	Total	Undiscounted	Discounted at 10%

					Estimated Future Net Cash Flow[1]	
	(MBbls)	(MBbls)	(MMcf)	(MBoe)	(in thousands)	
Proved reserves:						
Developed producing	81,222	13,485	708,955	212,866	$ 2,040,855	$ 1,088,148
Developed non-producing	604	508	57,899	10,762	110,681	62,525
Undeveloped	7,397	1,730	166,003	36,794	265,004	111,269
Total proved reserves	89,223	15,723	932,857	260,422	2,416,540	1,261,942
Probable reserves (risked at 50%)	16,662	2,334	129,770	40,625	336,976	100,586
Established reserves	105,885	18,057	1,062,627	301,047	$ 2,753,516	$ 1,362,528

(1) The present value of estimated future net cash flow includes the Alberta Royalty Tax Credit and is stated before deduction of income tax. **Estimated future net cash flow is not to be construed as the fair market value of our reserves.**

Reserves as of January 1, 2002
U.S. Presentation
(Net Reserves Using Constant Prices and Costs)

	Crude Oil	Natural Gas Liquids	Natural Gas	Total	Estimated Future Net Cash Flow[1] Undiscounted	Discounted at 10%
	(MBbls)	(MBbls)	(MMcf)	(MBoe)	(in thousands)	
Proved reserves:						
Developed producing	73,302	9,432	558,990	175,899	$ 2,040,855	$ 1,088,148
Developed non-producing	527	349	46,461	8,620	110,681	62,525
Undeveloped	6,320	1,218	139,485	30,785	265,004	111,270
Total proved reserves	80,149	10,999	744,936	215,304	$ 2,416,540	$ 1,261,942

(1) The present value of estimated future net cash flow includes the Alberta Royalty Tax Credit and is stated before deduction of income tax. **Estimated future net cash flow is not to be construed as the fair market value of our reserves.**

Production History

Our average daily crude oil, NGLs and natural gas production, before deduction of royalties, for the specified periods is set out in the following table:

Year Ended December 31,	Nine Months Ended

	1999(1)	2000(1)	2001(1)	September 30, 2002
Crude oil (Bbls/day)	11,416	12,089	20,592	23,117
NGLs (Bbls/day)	1,980	2,111	3,978	4,299
Total liquids (Bbls/day)	13,396	14,200	24,570	27,416
Natural gas (Mcf/day)	71,713	101,473	176,671	204,463
Total (Boe/day)	25,348	31,112	54,015	61,493

(1) Production for 1999, 2000 and 2001 is that of EnerMark Income Fund. Production attributable to pre-merger Enerplus is not included prior to the June 21, 2001 merger date. Production information for the merged Fund is included from June 21, 2001 forward.

Oil and Natural Gas Wells

The following table summarizes, as at December 31, 2001, our interests in producing and shut-in wells which we believe are capable of production. Although many of our wells produce both oil and natural gas, a well is categorized as an oil well or a natural gas well based upon the ratio of oil to natural gas production.

	Producing Wells				Shut-in Wells(1)			
	Oil		Natural Gas		Oil		Natural Gas	
Area	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	2,642	1,131	3,732	1,725	489	162	306	97
British Columbia	34	12	87	19	11	3	44	13
Saskatchewan	2,325	478	305	211	376	103	8	1
Total	5,001	1,621	4,124	1,955	876	268	358	111

(1) "Shut-in" wells means wells which are not producing but which may be capable of production. Shut-in wells in which we have an interest are located no further than 10 kilometres from gathering systems, pipelines or other means of transportation.

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Drilling Activity

During 2001, we participated in the drilling of 546 gross wells (321.6 net wells) with a 99% net well success rate, and for the nine months ended September 30, 2002, we participated in the drilling of 226 gross wells (181.0 net wells) with a 99% net well success rate. The following table summarizes the number and type of wells that we drilled or participated in drilling for the periods indicated. We did not participate in drilling any exploratory wells in those periods.

	Year Ended December 31,			Nine Months Ended September 30, 2002
	1999	2000	2001	

	Year Ended December 31,							
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Completed								
Oil wells	4	3.0	103	33.5	104	37.7	44	20.8
Natural gas wells	97	15.0	184	53.9	429	279.4	179	158.6
Dry and abandoned	4	2.0	15	3.4	13	4.5	3	1.6
Total	105	20.0	302	90.8	546	321.6	226	181.0
Success rate:		90%		96%		99%		99%

(1) Information for 1999, 2000 and 2001 is that of EnerMark Income Fund. Drilling activity attributable to pre-merger Enerplus is not included prior to the June 21, 2001 merger date. Drilling activity of the merged Fund is included from June 21, 2001 forward.

Landholdings

The following table summarizes our land holdings as of December 31, 2001:

	Developed Acres		Undeveloped Acres		Royalty Acres
	Gross	Net	Gross	Net	Net
Alberta	2,410,768	806,072	820,008	408,579	693,265
British Columbia	217,967	47,010	118,683	51,505	158,023
Saskatchewan	153,335	79,865	36,559	25,595	136,911
Other	695	189	617	617	2,665
Total	2,782,765	933,136	975,867	486,296	990,864

We have assigned a value of $24.3 million to our undeveloped landholdings as of December 31, 2001.

Capital Expenditures

The following table sets forth our capital expenditures for the years ended December 31, 1999, 2000 and 2001 and the nine months ended September 30, 2002:

	Year End December 31,			Nine Months Ended September 30,
	1999	2000	2001	2002
	(in thousands)			
Development drilling and completions	$ 15,036	$ 27,102	$ 83,004	$ 62,457
Plant and facilities	3,847	11,861	53,594	32,683
Office and other expenditures	1,888	1,033	6,682	5,900
	20,771	39,996	143,280	101,040
Producing property acquisitions	10,322	51,109	77,432	48,270

	Year End December 31,			Nine Months Ended September 30, 2002
Total capital expenditures	31,093	91,105	220,712	149,310
Property dispositions	(16,957)	(25,261)	(68,496)	(2,446)
Net capital expenditures	$ 14,136	$ 65,844	$ 152,216	$ 146,864

(1) Information for 1999, 2000 and 2001 is that of EnerMark Income Fund. Capital expenditures attributable to pre-merger Enerplus are not included prior to the June 21, 2001 merger date. Capital expenditures for the merged Fund is included from June 21, 2001 forward.

Development activities on our properties during 2002 are estimated to require capital expenditures of up to $130 million, of which $101 million was incurred to September 30, 2002.

Marketing

Our natural gas production is sold through a combination of physical and financial sale arrangements. As of September 30, 2002, approximately 41% of our natural gas is marketed in western Canada on the AECO spot market, which is a Canadian natural gas pricing benchmark similar to NYMEX Henry Hub in the United States. An additional 14% of our natural gas production is delivered directly to the U.S. export market and is priced against the NYMEX index. Approximately 36% of our production is dedicated to realized price pools managed by major aggregators.

We sell all of the crude oil that we produce at the lease site to refiners and marketers on 30 day, continuously renewing contracts that fluctuate with monthly spot market prices.

Risk Management

Commodity Price Risk Management Program

The prices that we receive for our crude oil and natural gas can fluctuate significantly. We have a commodity price risk management program that is designed to provide price protection on a portion of our future production in the event of an adverse commodity price movement, while retaining some exposure to upside price movements. The program is intended to reduce the volatility of our cash flows as well as to allow us to realize positive economic returns from our capital development and acquisition activities.

In 2001, we implemented a commodity price risk management program. This program was implemented in consultation with industry experts, our executive management and the board of directors of EnerMark. This program establishes comprehensive guidelines for our risk management activities including, but not limited to, the type of instruments that can be used as well as the size, timing and term of the individual hedging contracts. The plan is reviewed weekly by management to determine the amount of future production that will be hedged.

We frequently use three-way options for our oil and natural gas positions. A three-way option consists of a traditional collar (i.e., selling a call and purchasing a put) supplemented by the sale of a put option that reduces the cost that would otherwise be payable on the collar. The following table illustrates the mechanics of a three-way option, using the example of a US$30.00 sold call, a US$22.00 purchased put and a US$20.00 sold put.

WTI Price (US$/Bbl)	Result
WTI price greater than US$30.00	Enerplus receives US$30.00 and does not share in the upside beyond US$30.00
WTI between US$22.00 and US$30.00	Enerplus receives the actual WTI market price between US$22.00 and US$30.00
WTI between US$20.00 and US$22.00	Enerplus receives US$22.00

WTI Price (US$/Bbl)	Result
WTI below US$20.00	Enerplus receives the actual WTI market price plus US$2.00/Bbl (the difference between the purchased put and the sold put options)

For additional information regarding our commodity risk management program, please read "Management's Discussion and Analysis of Operating Results and Financial Condition Results of Operations Nine Months Ended September 30, 2002 Compared to Nine Months Ended September 30, 2001 Pricing and Price Risk Management" and Note 5 to our unaudited consolidated financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001.

Interest Rate Risk Management

As at September 30, 2002, 79% of our bank debt was based on floating interest rates. We have fixed the interest rate on the remaining 21% (or $75 million) using interest rate swaps for three-year terms. We may consider fixing an additional portion of our interest rate exposure depending on the forward interest rate market.

Currency Risk Management

At the current time, we have not hedged our exposure to the Canadian/U.S. dollar exchange rate, with the exception of the cross-currency swap associated with the senior unsecured notes. Since the majority of our oil and natural gas sales are based on U.S.-denominated indices, we are exposed to fluctuations in the Canadian/U.S. dollar exchange rate, and the decade-long weakening trend in the Canadian dollar has generally been a positive event for us. We believe that a sustained rally in the Canadian dollar exchange rate would require Canadian interest rates to continue to strengthen more than U.S. interest rates. Although we believe this risk is minimal, and are comfortable with our current exposure, we continually monitor our position.

Title to Properties

We believe that our title to the underlying properties is good and defensible in accordance with standards generally accepted in the oil and gas industry. We believe that any defects in title will not, in the aggregate, materially interfere with the use of the underlying properties and will not, in the aggregate, materially adversely affect the value of our interest.

The underlying properties are typically subject, in one degree or another to one or more of the following:

- lessor royalties under oil and natural gas leases, overriding royalties and other burdens;
- contractual obligations, including, in some cases, development obligations, arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing unpaid suppliers and contractors and contractual liens under operating agreements;
- pooling and unitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect surface property.

To the extent that these burdens and obligations affect our rights to production and the value of production from the underlying properties, they have been taken into account in calculating our interests and in estimating the size and value of our reserves. We believe that the burdens and obligations affecting the underlying properties are conventional in the industry for similar properties. We also believe that the burdens and obligations do not in the aggregate materially interfere with the use of the underlying properties and will not, in the aggregate, materially adversely affect the value of our interest.

Regulatory Environment

The oil and natural gas industry is subject to extensive controls and regulation imposed by various levels of government. Although we do not expect that these controls and regulation will affect our operations in a manner materially different than they would affect other Canadian oil and gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends, in part, on oil type and quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance and other contractual terms. Oil exports may be made pursuant to export contracts with terms not exceeding one year, in the case of light crude, and not exceeding two years, in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the National Energy Board and the issue of such a licence requires the approval of the Governor in Council.

Pricing and Marketing Natural Gas

In Canada, the price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. Natural gas exported from Canada is subject to regulation by the National Energy Board and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the National Energy Board and the government of Canada. Natural gas exports for a term of less than two years or for a term of 2 to 20 years (in quantities of not more than 30,000 cubic metres per day, must be made pursuant to an order of the National Energy Board. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity, requires an exporter to obtain an export licence from the National Energy Board and the issue of such a licence requires the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement among the governments of Canada, the U.S. and Mexico became effective. In the context of energy resources, Canada continues to remain free to determine whether exports to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements and, except as permitted in enforcement of countervailing and antidumping orders and undertakings, minimum or maximum import price requirements.

The North American Free Trade Agreement contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The North American Free Trade Agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

In addition to federal regulations, each province in Canada has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the probability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the freehold mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location and field discovery date.

From time to time, the federal and provincial governments in Canada have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects although the trend is toward eliminating these types of programs in favour of long term programs which enhance predictability for producers. Oil and natural gas royalty holidays and reductions for specific wells will reduce the amount of Crown royalties paid by us to the provincial governments.

On October 13, 1992, the government of Alberta implemented major changes to its royalty structure and created incentives for exploring and developing oil and natural gas reserves. The incentives created include: (i) a one year royalty holiday on new oil discovered on or after October 1, 1992; (ii) incentives by way of royalty holidays and reduced royalties on reactivated, low productivity, vertical re-entry and horizontal wells; (iii) introduction of separate par pricing for light/medium and heavy oil; and (iv) a modification of the royalty formula structure through the implementation of a third tier royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

In Alberta, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying exploratory gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 is eligible for a royalty exemption for a period of 12 months, up to a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 meters is also subject to a royalty exemption, the amount of which depends on the depth of the wells.

In Alberta, certain producers of oil or natural gas are also entitled to a credit against the royalties payable to the Alberta Crown by virtue of the Alberta royalty tax credit program. The Alberta royalty tax credit program is based on a price-sensitive formula, and the Alberta royalty tax credit program rate varies between 75%, at prices for oil below $100 per cubic meter, and 25%, at prices above $210 per cubic meter. The Alberta royalty tax credit program rate is applied to a maximum of $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from companies claiming maximum entitlement to Alberta royalty tax credit program will generally not be eligible for Alberta royalty tax credit program. The Alberta royalty tax credit program rate is established quarterly based on the average "par price", as determined by the Alberta Resource Development Department for the previous quarterly period.

In British Columbia, the amount payable as a royalty in respect of oil depends on the vintage of the oil (whether it was produced from a pool discovered before or after October 31, 1975), the quantity of oil produced in a month and the value of the oil. Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and a prescribed minimum price. Natural gas produced in association with oil has a minimum royalty of 8% while the royalty in respect of other natural gas may not be less than 15%.

Effective October 1, 2002, the government of Saskatchewan revised its fiscal regime for the oil and gas industry. Some royalties on wells existing as of that date will remain unchanged and will therefore be subject to various periods of royalty/tax deduction. The changes include new lower royalty and tax structures applicable to both oil, natural gas and associated natural gas (natural gas produced from oil wells), a new system of volume incentives and a reduced corporation capital tax resource surcharge rate.

The new fiscal regime for the Saskatchewan oil and gas industry provides an incentive to encourage exploration and development through a revised royalty/tax structure for oil and natural gas wells with a finished drilling date on or after October 1, 2002 or incremental oil production due to a new or expanded waterflood project with a commencement date on or after October 1, 2002. This "fourth tier" Crown royalty

rate, applicable to both oil and natural gas, is price sensitive and ranges from a minimum 5% at a base price to a maximum of 30% at a price above the base price. A fourth tier freehold tax structure, calculated by subtracting a production tax factor of 12.5 percentage points from the corresponding Crown royalty rates, has also been created which is applicable to conventional oil, incremental oil from new or expanded waterfloods and natural gas. The fourth tier royalty/tax structure is also applicable in respect of associated natural gas that is gathered for use or sale which is produced either from oil wells with a finished drilling date on or after October 1, 2002 and oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of natural gas per $1m^3$ of oil. In addition, volume-based royalty/tax reduction incentives have been changed such that a maximum royalty of 2.5% now applies to various volumes of both oil and natural gas, depending on the depth and nature of the well (up to 16,000 m^3 of oil in the case of deep exploratory wells and 25,000 m^3 of natural gas produced from exploratory wells). The royalty/tax category with respect to re-entry and short sectional horizontal oil wells has been eliminated such that all horizontal oil wells with a finished drilling date on or after October 1, 2002 will receive fourth tier royalty/tax rates and incentive volumes. Further changes include the reduction of the corporation capital tax resource surcharge rate from 3.6% to 2.0% and the expansion of the "deep oil well" definition to include oil wells producing from a zone deeper than 1,700 meters provided that the zone is within a geological system deposited during the Mississippian Period or earlier or from a zone that was deposited before the Bakken zone regardless of depth.

Oil and natural gas royalty holidays and reductions for specific wells reduce the amount of Crown royalties paid by Enerplus to the provincial governments. The Alberta royalty tax credit program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties. These incentives result in increased net income and funds from our operations.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures. A breach of such legislation may result in the imposition of material fines and penalties, the revocation of necessary licenses and authorizations and civil liability for pollution damage.

In Alberta, environmental compliance is governed by the *Alberta Environmental Protection and Enhancement Act*, which imposes certain environmental responsibilities on oil and natural gas operators in Alberta and imposes penalties for violations. In Saskatchewan, environmental compliance is governed by the *Environmental Management and Protection Act* (Saskatchewan). In British Columbia, energy projects may be subject to review pursuant to the provisions of the *Environmental Assessment Act* (British Columbia). The *Environmental Assessment Act* (British Columbia) rolls the previous processes for the review of major energy projects into a single environmental assessment process which contemplates public participation in the environmental review.

In 1994, the United Nations' Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol which will require participating countries, upon ratification, to reduce their emissions of carbon dioxide and other greenhouse gases. Canada has not ratified the Kyoto Protocol, but should it do so reductions in greenhouse gases from our operations may be required which could result in increased capital expenditures and operating costs.

We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment. We will be taking such steps as required to ensure compliance with the *Alberta Environmental Protection and Enhancement Act*, the *Environmental Management and Protection Act* (Saskatchewan), the *Environmental Assessment Act* (British Columbia) and similar legislation or requirements in other jurisdictions in which we operate. We believe that we are in material compliance with applicable environmental laws and regulations. We also believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards.

RECENT DEVELOPMENTS

Potential Acquisitions

We continue to evaluate potential acquisitions of oil and natural gas properties, companies and trusts and other energy-related assets as part of our ongoing acquisition program. We are currently in negotiations regarding several potential acquisitions which together could have purchase prices aggregating approximately $200 million. As of the date of this prospectus, we have not reached agreement with the potential sellers on the price or terms of any of the potential acquisitions. Accordingly, we cannot predict whether any of these current opportunities will result in one or more acquisitions for the Fund.

Acquisition of Celsius Energy Resources Ltd.

On October 21, 2002, we acquired all of the outstanding shares and retired the debt of Celsius Energy Resources Ltd., a private oil and natural gas producer based in Calgary, Alberta which was a wholly owned Canadian subsidiary of U.S.-based Questar Market Resources Inc., for total cash consideration of $165.9 million, after working capital adjustments. On October 22, 2002, Celsius was amalgamated with EnerMark.

The Celsius properties are primarily located in Alberta and northeastern British Columbia. Many of the Celsius properties are located in areas in which we were active prior to the acquisition, including the Verger, Countess, Pine Creek and Deep Basin areas. The gross average daily production from the Celsius properties for September 2002 was approximately 5,750 Boe/day consisting of a 22,476 Mcf/day of natural gas, 1,724 Bbls/day of crude oil and 280 Bbls/day of NGLs. We estimate that the Celsius properties contained 18 MMBoe of established reserves as of July 31, 2002, resulting in an acquisition cost of $27,826 per daily producing Boe and $8.89 per Boe of established reserves. The Celsius properties have operating characteristics that are generally consistent with our existing properties. Included in the acquisition are approximately 103,000 net acres of undeveloped land that will provide further development opportunities to us through potential farmout and swap agreements.

Please read "Appendix B Information Regarding Celsius Energy Resources Ltd.," which contains additional information regarding the operations and reserves of Celsius, including a description of certain assumptions made in preparing the reserve evaluations of Celsius.

Issuance of Trust Units

On September 12, 2002, we completed an offering of 4,750,000 trust units for gross proceeds of $127,538,000. The offering was conducted exclusively in Canada, and the net proceeds of $120,886,000 were used to reduce debt incurred with respect to acquisitions, capital expenditures and general corporate expenditures.

Issuance of Senior Unsecured Notes

On June 19, 2002, EnerMark completed the private placement of US$175 million of senior unsecured notes to a group of United States institutional investors. The notes have a coupon rate of 6.62% based on the par price and have a twelve year term with a ten year average life, as 20% of the principal repayment is required on June 19, 2010 and annually thereafter, until June 19, 2014. The net proceeds were used to repay bank indebtedness, which reduced the amount of credit available under EnerMark's bank facilities. For additional information, please read Note 4 to our unaudited consolidated financial statements for the nine months ended September 30, 2002 included in this prospectus.

MANAGEMENT AND CORPORATE GOVERNANCE

Governance of Enerplus

General

Under the terms of the trust indenture among EnerMark, ERC and CIBC Mellon Trust Company, as trustee, the trustee is given broad powers and authorities over the administration and management of the Fund. Pursuant to the trust indenture, the trustee has delegated to the board of directors of EnerMark the supervision of the management of the business and affairs of the Fund, including the supervision of EGEM in carrying out the duties delegated to it under the trust indenture and the management agreement. Among other things, the board of directors of EnerMark is given responsibility for all matters relating to offerings of securities of the Fund, take-over bids or similar transactions involving the Fund or its subsidiaries, the terms, amendment or execution of material contracts (including the royalty, management and governance agreements) on behalf of the Fund, the voting of securities held by the Fund (including the shares of EnerMark), the redemption of trust units, any borrowings or acquisitions made by the Fund or its subsidiaries and the approval of the Fund's public disclosure documents.

Pursuant to the trust indenture and in accordance with the management agreement, the trustee and the board of directors of EnerMark have retained and delegated certain authority to EGEM to provide comprehensive management services to and administer and manage the day to day operations of the Fund and the Operating Companies, subject to the supervision of the board of directors of EnerMark. EGEM has also been delegated the authority to make executive decisions on behalf of the Fund and the Operating Companies, as long as those decisions conform to the general policies and principles established by the board of directors of EnerMark.

Governance Agreement

The Fund, as the sole shareholder of EnerMark, is entitled to elect the directors of EnerMark and must do so in accordance with a vote of the Fund's unitholders. Under the terms of a governance agreement among the Fund, EnerMark, ERC, EGEM and CIBC Mellon Trust Company, as trustee of the Fund, EGEM is entitled to nominate three persons to serve on the board of directors of EnerMark, and the balance of the directors are to be nominated by the unitholders. Following those nominations, the Fund and EnerMark will facilitate the election of those persons to EnerMark's board of directors. Since the board of directors of EnerMark must consist of at least seven and a maximum of eleven members, a majority of the EnerMark directors will always have been nominated by the Fund's unitholders. The governance agreement also provides that the boards of directors of EnerMark and its wholly-owned subsidiary, ERC, are to be identical, and that any dividends received by EnerMark from ERC must immediately be paid by EnerMark to the Fund.

Corporate Governance Guidelines

Enerplus believes that its approach to corporate governance is in compliance with the non-mandatory guidelines for effective corporate governance established by the Toronto Stock Exchange and continually reviews its compliance with other published recommendations, including the recently proposed rules of the New York Stock Exchange. The board of directors is currently comprised of eight members, a majority of whom are independent. Additionally, the Chairman of the board of directors is independent.

The board of directors has responsibility for the stewardship of Enerplus, including responsibilities for planning and evaluation, financial management, operations, human resources and environment and safety. The board of directors has taken specific responsibility for:

- adopting a strategic planning process;
- identifying principal risks and implementing risk management systems;
- succession planning, including nominating, training and monitoring senior management;
- development of a communications policy; and
- ensuring the integrity of internal control and management information systems.

Currently, the board meets a minimum of six times per year and each scheduled board meeting is followed by a meeting of the independent directors without the presence of management.

The board of directors has approved a Code of Business Conduct and Conflict of Interest which sets certain standards of ethical behaviour and deals with conflicts of interest, compliance with laws, outside business interests, entertainment, gifts and favours, disclosure, confidential information, securities trading and reporting. Each director must adhere to the standards described in the Code and must review, sign and deliver to the Chairman of the board of directors a copy of this Code each year.

The board of directors discharges its responsibilities acting either in its entirety or through one of its committees. Each of the Corporate Governance Committee and the Audit and Risk Management Committee is comprised of three independent directors. The Compensation and Human Resources Committee is comprised of two independent directors and one director who is not independent. The Environment, Safety and Reserves Committee consists of one independent director and one director who is not independent.

Directors and Officers of EnerMark and Officers of EGEM

The Fund does not have any of its own directors or officers. The following is a summary of information relating to the directors and officers of EnerMark, the primary operating subsidiary of the Fund whose board of directors is responsible for the stewardship of Enerplus, and the officers of EGEM, which provides administrative and management services to Enerplus pursuant to the management agreement.

Directors of EnerMark

Name and Municipality of Residence	Director Since	Principal Occupation
André Bineau(2) Montréal, Québec	February, 1996	Vice President of Association de bienfaisance et de retraite des policiers et policières de la Ville de Montréal (a municipal pension plan)
Derek J.M. Fortune(4)(5)(6) Ottawa, Ontario	June, 2001	Secretary/Manager, City of Ottawa Superannuation Fund (a municipal pension plan)
Gordon J. Kerr(5)(7) Calgary, Alberta	May, 2001	President and Chief Executive Officer of EGEM.
Douglas R. Martin(1)(4)(5)(8) Calgary, Alberta	July, 2000	President of Charles Avenue Capital Corp. (a private merchant banking company) since April, 2000.
Robert Normand(2)(4)(6) Montréal, Québec	June, 2001	Businessman.
Eric P. Tremblay(3)(7) Calgary, Alberta	January, 2001	Senior Vice President, Capital Markets of EGEM.
Harry B. Wheeler(2)(3) Calgary, Alberta	January, 2001	President of Colchester Investments Ltd. (a private investment firm).
Robert L. Zorich(7)(9) Houston, Texas	January, 2001	Managing Director of EnCap Investments L.L.C. (a wholly owned subsidiary of El Paso Corporation, which provides private equity financing to the oil and gas industry)

(1) Chairman of the Board of Directors.

(2) The Audit and Risk Management Committee is comprised of Robert Normand as Chairman, André Bineau and Harry B. Wheeler.

(3) The Environment, Safety and Reserves Committee is comprised of Harry B. Wheeler as Chairman and Eric P. Tremblay.

(4) The Corporate Governance Committee is comprised of Douglas R. Martin as Chairman, Robert Normand and Derek J. M. Fortune.

(5) The Compensation and Human Resources Committee is comprised of Derek J. M. Fortune as Chairman, Douglas R. Martin and Gordon J. Kerr.

(6) Prior to the merger of Enerplus and EnerMark Income Fund on June 21, 2001, each of Derek J.M. Fortune and Robert Normand was a director of ERC, the entity responsible for governance of Enerplus Resources Fund prior to the merger. Mr. Fortune was a director of ERC since June 1992 and Mr. Normand was a director of ERC since March 1998.

(7) Nominee of EGEM pursuant to the management agreement.

(8) From 1991 to 2000, Mr. Martin was director of Coho Energy, Inc., an oil and natural gas corporation that was listed on the Toronto Stock Exchange and NASDAQ. In 1999, Coho filed for protection under United States federal bankruptcy law, from which it was released in April, 2000. The directors of Coho were not held responsible for any actions. Mr. Martin resigned as a director of Coho in April of 2000.

(9) In late 1997, Mr. Zorich was appointed to the board of directors of Benz Energy Inc., a Vancouver Stock Exchange listed company at the time, as a representative of Mr. Zorich's employer, EnCap Investments L.L.C., which had provided certain financing to Benz. On November 8, 2000, Benz, together with its wholly-owned subsidiary, Texstar Petroleum Inc., jointly filed a petition for protection under United States federal bankruptcy law, and on January 19, 2001, the shares of Benz were made subject to a cease trade order by the Alberta Securities Commission and suspended from trading on the Canadian Venture Exchange Inc. (the successor to the Vancouver Stock Exchange) for failing to file required financial information.

Officers of EnerMark and EGEM

The name, municipality of residence and position held for each officer of EnerMark and EGEM are set out below:

Name and Municipality of Residence	Position with EnerMark	Position with EGEM
Gordon J. Kerr Calgary, Alberta	President and Chief Executive Officer	President and Chief Executive Officer
Heather J. Culbert Calgary, Alberta	Senior Vice President, Corporate Services	Senior Vice President, Corporate Services
Garry A. Tanner Calgary, Alberta	N/A	Senior Vice President, Business Development
Eric P. Tremblay Calgary, Alberta	Senior Vice President, Capital Markets	Senior Vice President, Capital Markets
Robert J. Waters Calgary, Alberta	Senior Vice President and Chief Financial Officer	Senior Vice President and Chief Financial Officer
Jo-Anne M. Caza Calgary, Alberta	Vice President, Investor Relations	N/A
Daryl W. Cook Calgary, Alberta	Vice President, Operations	N/A
Ian Dundas Calgary, Alberta	N/A	Vice President
Wayne T. Foch Calgary, Alberta	Vice President, Finance	Vice President, Finance
Gerald F. Stevenson Calgary, Alberta	Vice President, Acquisitions	N/A
Wayne G. Ford Calgary, Alberta	Controller, Operations	N/A
Rodney D. Gray Calgary, Alberta	Controller, Finance	Controller, Finance
Christina S. Meeuwsen Calgary, Alberta	Corporate Secretary	Corporate Secretary

Set forth below is additional information regarding each director of EnerMark and each officer of EnerMark and EGEM.

André Bineau, Director

Mr. Bineau is a Chartered Financial Analyst and has more than 35 years of experience in the investment industry. For the past seventeen years, Mr. Bineau has held the position of Vice President, Investments of Association de bienfaisance et de retraite des policiers et policières de la Ville de Montréal, a corporation managing the benefits and the investments of pension funds totaling over $3.0 billion. Mr. Bineau currently sits on the investment committees of several private and public Canadian corporations. Prior to 1985, Mr. Bineau was Vice President, Investments of Trust General du Canada for four years and before that, for seven years, he held various responsibilities, including Director of the Canadian equity department, of Caisse de dépôt et placement du Québec. Mr. Bineau is a graduate of l'École des Hautes Études Commerciales and of the Faculty of Law of the University of Montreal.

Derek J.M. Fortune, Director

Mr. Fortune was granted the designation of Certified General Accountant by the Certified General Accountants Association of Ontario in 1967. At the same time, Mr. Fortune commenced employment with the City of Ottawa as Chief Accountant. In 1969, he assumed responsibilities for the pension fund of the City of Ottawa as Secretary Manager, a position he continues to occupy. Mr. Fortune currently serves as a director of a private company (a consortium of pension funds) and has served on a number of private and public boards in the past.

Douglas R. Martin, Chairman of the Board of Directors

Mr. Martin has been President of Charles Avenue Capital Corp., a private merchant banking company, since April 2000. From 1993 until 2000, Mr. Martin was Chairman and Chief Financial Officer of Pursuit Resources Corp, a public oil and gas corporation that was acquired by EnerMark Income Fund in April 2000. From 1972 until 1993, Mr. Martin held positions of increasing importance with N.M. Davis Corp., Dome Petroleum Ltd. and Interhome Energy Inc. (now Enbridge Inc.), and was the Senior Vice President and Chief Financial Officer of Coho Energy Inc. from 1989 until 1993. Mr. Martin graduated from the University of Toronto in 1966 with a B.A. in Political Science, and received his Chartered Accountant designation from the Ontario Institute of Chartered Accountants in 1969. He also graduated with Honours from York University in 1972 with an MBA in Finance. Mr. Martin currently serves on the board of directors of Stars Aviation Inc., Alberta Benefits Inc., Matrix Petroleum Inc. and Rock Creek Resources Inc.

Robert Normand, Director

Mr. Normand graduated from l'École des Hautes Études Commerciales (Université de Montréal) in 1966, received a Chartered Accountant designation and became a member of the Québec Institute of Chartered Accountants the same year. Mr. Normand acted as an external auditor for Richter Usher & Vineber and Coopers & Lybrand until 1968 and held accounting responsibilities with two industries before joining Gaz Métropolitain in late 1972 as Assistant CFO. Mr. Normand ultimately held the position of CFO from 1980 until his retirement in 1997. Mr. Normand was President of the Financial Executives Institute Canada in 1992, Vice President U.S. in 1993 and is an active member of the Montréal Chapter. Since 1997, Mr. Normand has been appointed as a director of several private and public corporations operating in various fields of the economy, namely printing and media (Quebecor World Inc., Dolan Media USA), energy (Vista Midstream Inc.) mining (Cambior Inc., Aurizon Mines), financial (ING Canada Ltd.), manufacuring (Commercial Alcohols Ltd., Concert Industries Inc.) and restaurants (Sportscene Inc.).

Harry B. Wheeler, Director

Mr. Wheeler graduated from the University of British Columbia in 1962 with a degree in Geology. From 1962 to 1966, Mr. Wheeler worked with Mobil in Canada and Libya and from 1967 to 1972 was employed by International Resources Ltd., in London, England and Denver, Colorado. He was a Director of Quintette

Coal Ltd., Vice President of Amalgamated Bonanza Petroleum Ltd. and operator of his private company before founding Cabre Exploration Ltd. in 1980. Mr. Wheeler was Chairman of Cabre until it was acquired by EnerMark Income Fund in December 2000. Mr. Wheeler is currently a director of Arcis Corp., BelAir Energy Corporation and the Alberta Motor Association.

Robert L. Zorich, Director

Mr. Zorich is Managing Director and co-founder of EnCap Investments L.L.C., an investment manager and leading provider of private equity capital to the independent sector of the oil and gas industry. Prior to the formation of EnCap, Mr. Zorich was a Senior Vice President in charge of the Houston office of Trust Company of the West, a large, privately-held pension fund manager. Prior to joining Trust Company of the West in September 1986, Mr. Zorich co-founded MAZE Exploration, Inc., serving as its Co-Chief Executive Officer. During the first seven years of his career, Mr. Zorich was employed by RepublicBank Dallas as a Vice President and Division Manager in the Energy Department. Approximately half of his tenure with Republic was spent managing the bank's energy office in London, where he assembled a number of major project financings for development in the North Sea. Mr. Zorich received his B.A. in Economics from the University of California at Santa Barbara in 1971. He also received a Masters Degree in International Management (with distinction) in 1974 from the American Graduate School of International Management in Phoenix, Arizona. Mr. Zorich currently serves on the Board of Directors of Laredo Energy, L.P., AROC, Inc., Plantation Energy and Sierra Resources and is a member of the Independent Petroleum Association of America and TIPRO.

Gordon J. Kerr, B.Comm., C.A., Director and President and Chief Executive Officer of EnerMark and EGEM

Mr. Kerr graduated from the University of Calgary in 1976 with a Bachelor of Commerce degree. He received a Chartered Accountant designation and was admitted as a member of the Institute of Chartered Accountants of Alberta in 1979. Mr. Kerr commenced employment in the oil and gas industry in 1979 and held various positions with Petromark Minerals Ltd., Bluesky Oil & Gas Ltd. and Bluesky's successor, Mark Resources Inc., ultimately holding the position of Vice President Finance, Chief Financial Officer and Corporate Secretary until Mark's reorganization into EnerMark Income Fund in 1996. In 1996, Mr. Kerr commenced employment with the Enerplus Group holding positions of increasing responsibility including the position of Executive Vice President for the Enerplus Group prior to his appointment, in May 2001, to President and Chief Executive Officer.

Heather J. Culbert, Senior Vice President, Corporate Services of EnerMark and EGEM

As Senior Vice President, Corporate Services, Ms. Culbert leads the administration, human resources, and management information systems (MIS) teams within the Enerplus Group. She was appointed to this position in February 2001 following five years with the Enerplus Group as Vice President of Administration and MIS. Ms. Culbert has more than 20 years experience in the fields of technology, strategic planning, and general management. She has held various positions in the energy sector, including division manager of Cody Energy, a junior oil and gas company, in 1994 and 1995. She has also held positions in the technology sector as Director of MIS, Manager of MIS, and as Director of Professional Services for a national systems consulting company (Crowntek, now General Electric). Ms. Culbert's educational background included a computer technology diploma from the Southern Alberta Institute of Technology and management certification from North Eastern University of Massachusetts.

Garry A. Tanner, MBA, P. Eng., Senior Vice President, Business Development of EGEM

As Senior Vice President, Business Development, Mr. Tanner is responsible for identifying and pursuing mergers, acquisitions and divestments, as well as other new strategic business opportunities, for the Fund. Mr. Tanner was formerly with EnCap L.L.C., a subsidiary of El Paso, which purchased EGEM in 2000. He led a transaction management team as Senior Vice President of El Paso Merchant Energy Canada until assuming his current position with EGEM in September 2001. Prior to joining EnCap in 1997, Mr. Tanner worked for 13 years in various upstream engineering and management positions with Exxon Company, USA.

Mr. Tanner holds a Bachelor of Science degree in Chemical Engineering (1984) from the University of Kansas and a Masters degree in Business Administration (1997) from the University of Texas at Austin.

Eric P. Tremblay, B. Eng., Director and Senior Vice President, Capital Markets of EnerMark and EGEM

Mr. Tremblay was appointed Senior Vice President, Capital Markets in 2000. He is responsible for product development, marketing, investor relations and equity financing, and is also a member of the board of directors of EnerMark. Mr. Tremblay joined the Enerplus Group in 1993 as Manager, Corporate Development and advanced to Senior Vice President, Corporate Development prior being appointed to his current position. He graduated in 1987 from Ryerson Polytechnic University in Toronto with a Bachelor of Engineering degree in Aerospace Engineering and pursued a career as a structural design engineer in the North American aerospace industry. He held positions with British Petroleum, Canadair (a subsidiary of Bombardier Inc.) and the Boeing Airplane Company before joining the Enerplus Group.

Robert J. Waters, MBA, C.A., Senior Vice President and Chief Financial Officer of EnerMark and EGEM

Mr. Waters joined the Enerplus Group as Senior Vice President and Chief Financial Officer in December 2001 following three-and-a-half years as Vice President, Chief Financial Officer at Pengrowth Energy Trust. Prior to his service at Pengrowth, Mr. Waters worked for Norcen Energy Resources for ten years in a series of increasing responsible positions in the areas of audit, tax and corporate development. He left the position of treasurer to join Pengrowth in 1998. Mr. Waters started his career in 1984 with Thorne Riddell (now KPMG LLP). Mr. Waters holds an Honours Bachelor of Business Administration and a Masters of Business Administration from York University, Toronto. He received his Chartered Accountant designation in 1986.

Jo-Anne M. Caza, Vice President, Investor Relations of EnerMark

Ms. Caza joined the Enerplus Group in 1996, bringing over 12 years experience in the marketing and corporate communications industry. Previously, she was a partner in a Calgary-based marketing and communications firm, acting as Senior Account Manager for a variety of corporate and retail clients. Ms. Caza spent nine years working in the television and radio industry, primarily in the areas of marketing and promotions.

Daryl W. Cook, P. Eng., Vice President, Operations of EnerMark

Mr. Cook joined the Enerplus Group as Manager of Engineering in 1995 and was promoted to Vice President of Operations in 1997. Mr. Cook started his career with Pacific Petroleum Ltd. in 1976 as a reservoir engineer in Calgary. He joined Husky Oil Limited in 1979 as a reservoir engineer and transferred to Lloydminster in 1980 to join the heavy oil production group. In 1982, he transferred back to Calgary with Husky to join the conventional oil group and left Husky in 1984 to join Bluesky Oil and Gas Ltd. as senior reservoir engineer, and was promoted to Manager of Engineering in 1984. In 1987 Mr. Cook joined a subsidiary gas marketing company called PSR Gas Ventures as Vice President, Marketing. He returned to Mark Resources Inc. in 1988 as Manager, Production until 1993, when he joined Equis Energy Corp. Mr. Cook graduated from the University of Saskatchewan in 1976 with a B.Sc. in Geological Engineering.

Wayne T. Foch, C.G.A., Vice President, Finance of EnerMark and EGEM

Mr. Foch is a Certified General Accountant (Alberta) with over 25 years experience in the petroleum and natural gas industry. He was employed in a variety of increasingly senior accounting positions with several medium and large exploration and production companies before joining Mark Resources Inc. in 1985. In 1996, when Mark was converted into EnerMark Income Fund, Mr. Foch held the position of Controller of Mark. Since that time, and immediately prior to his appointment as Vice President, Finance for the Enerplus Group, he served as Treasurer for EnerMark Income Fund.

Gerald F. Stevenson, P. Eng., Vice President, Acquisitions of EnerMark

Mr. Stevenson joined Enerplus as Vice President, Acquisitions in 2001. He is responsible for identifying and acquiring strategically appropriate assets for the Enerplus portfolio. With more than 30 years experience in oil and gas exploitation, Mr. Stevenson has worked with Imperial Oil, Hudson's Bay Oil & Gas; Dome Petroleum, Texaco Canada Resources and Suncor Inc. In 1991, he was appointed Senior Vice President, Engineering and Production at North Canadian Oils Ltd. In 1993, he joined Waterous & Co. as an associate and in 1998 and 1999 served as Interim President and Chief Executive Officer with Hurricane Hydrocarbons Ltd. which, at the time, was subject to insolvency proceedings. His most recent position was as a consultant with Waterous Securities. Mr. Stevenson holds Bachelor of Science and Master of Science degrees, both in Mechanical Engineering, from the University of Saskatchewan.

Ian Dundas, Vice President of EGEM

As Vice President, Merchant Capital of EGEM, Mr. Dundas is a senior member of a team responsible for identifying and pursuing new opportunities for mergers and acquisitions as well as other new business opportunities. Prior to joining EGEM in 2000, Mr. Dundas worked for Enron Canada from 1996 to 2000 in a series of capacities, ultimately holding the position of Director, Merchant Capital. Prior thereto, Mr. Dundas was a corporate lawyer with the firm Blake, Cassels & Graydon LLP, specializing in banking, oil and gas and general corporate transactions. Mr. Dundas graduated with Distinction from the University of Calgary in 1990 with a Bachelor of Commerce, majoring in Finance, and graduated with Distinction from the University of Alberta in 1994 with a Bachelor of Laws. Mr. Dundas currently serves on the board of directors of Crescent Point Energy Ltd., a Toronto Stock Exchange listed junior oil and gas company.

Wayne G. Ford, C.M.A., Controller, Operations of EnerMark

As Controller of Operations for the Enerplus operating companies, Mr. Ford is responsible for all daily accounting and management functions. Mr. Ford joined the Enerplus Group in August 2000 and brings over twenty years of executive accounting and financial experience in corporate management, strategy and development. Prior to joining the Enerplus Group, Mr. Ford served as Controller or CFO for several public and private junior oil and gas companies. Mr. Ford received his Certified Management Accountant designation in 1986.

Rodney D. Gray, C.A., Controller, Finance of EnerMark and EGEM

Mr. Gray joined the Enerplus Group as Controller, Finance in June 2002. He received his designation as a Chartered Accountant in 1996 after having graduated from Queen's University in 1993 with a Bachelor of Commerce Honours degree. Mr. Gray began his career with KPMG LLP where he spent five years specializing in assurance and advisory services to the oil and gas industry. He left KPMG LLP as a Manager in 1998 to join Berkley Petroleum Corp. as Manager, Financial Reporting. He was promoted to Controller in 1999 and remained with the organization for three years. Prior to joining the Enerplus Group Mr. Gray worked as an independent consultant in the oil and gas industry.

Christina S. Meeuwsen, Corporate Secretary of EnerMark and EGEM

Ms. Meeuwsen joined the Enerplus Group in 1987 as Manager, Human Resources, became Assistant Corporate Secretary in 1993 and has held the position of Corporate Secretary since 1996. Prior thereto, from 1971 to 1972, Ms. Meeuwsen was employed as a consultant by the Fédération Nationale du Batiment, in Paris, France. Ms. Meeuwsen graduated ès Lettres from the Faculté de Lettres, Paris, France in 1970.

Management Agreement

We have entered into a management agreement under which we have retained the services of EGEM to identify, assess and assist in the acquisition, disposition and ongoing management of our properties and matters generally pertaining to the management, administration and operations of the Operating Companies and the Fund, subject to the overall supervision and review of the board of directors of EnerMark. In addition, EGEM advises us and, where appropriate, arranges for professional advice and other such support as may be necessary for both us and CIBC Mellon Trust Company, the trustee, to discharge our responsibilities under the trust indenture, the ERC royalty indenture and the royalty agreements. Please read "Description of the Royalties and the Subordinated Note."

Management and Performance Fees

The management agreement provides that EGEM is entitled to receive a base management fee, payable on a quarterly basis, equal to 2.75% of total operating income in the applicable quarter. Total operating income is comprised of gross revenue less royalties paid to third parties and operating expenses from all properties and from the business, operations and assets of the Fund and the Operating Companies.

EGEM is also entitled to receive a "total return performance fee" of between 0% and 2% of the Fund's total operating income based on the total return of the trust units in a calendar year (except for 2001, in which the fees were based on the period from May 10, 2001 to December 31, 2001). The total return performance fee is calculated in the following manner:

If the total return on Enerplus trust units (based on the amount of distributions paid plus any appreciation in our trust unit price) exceeds 11%, then EGEM is guaranteed to receive a minimum total return performance fee of 0.5% of our total operating income.

If the total return on Enerplus trust units is less than the average daily yield on 10-year Government of Canada bonds plus 5%, then no total return performance fee will be paid (subject to the minimum payment described above).

If the total return on Enerplus trust units exceeds the average daily yield on 10-year Government of Canada bonds plus 15%, then the total return performance fee will be 2% of our total operating income.

If the total return on Enerplus trust units is between the average daily yield on 10-year Government of Canada bonds plus a factor of 5% to 15%, than a sliding scale calculation (ranging from 0% to 2% of our total operating income) will be used (subject to the minimum payment described above).

Additionally, EGEM receives a "relative performance fee" of between 0% and 2% of our total operating income each calendar year. The fee is based on the total return of the Fund compared to a peer group of certain other Canadian conventional oil and gas energy funds. The relative performance fee is calculated using a percentage equal to 2% divided by the number of trusts in the top half of the rankings multiplied by the number of rankings which Enerplus is below the number one ranking and subtracting the product obtained thereby from 2%. If the resulting value obtained is less than zero, then no relative performance fee will be paid. Otherwise, the relative performance fee will be the amount obtained by multiplying the resulting percentage (not to exceed 2%) by our total operating income. In effect, Enerplus must rank at least fourth out of the eight largest (by market capitalization) conventional oil and gas trusts (including Enerplus) before EGEM will receive a relative performance fee.

The board of directors of EnerMark reviews the relative performance fee arrangements annually with EGEM to ensure that, in its opinion, the interests of EGEM are best aligned with the interests of the unitholders. However, any amendments to the fee relative performance structure would have to be approved by EGEM.

In the year ended December 31, 2001, a total of $9,323,000 was paid by Enerplus to EGEM for the base management fee. In connection with the merger of Enerplus Resources Fund and EnerMark Income Fund on June 21, 2001 and the concurrent amendments to the management fee structure, EGEM was guaranteed a minimum performance fee of $5,000,000 in 2001, which was paid through the issuance to EGEM of

172,500 trust units and was capitalized as part of the merger cost. Prior to the merger, the management agreement did not provide for the payment of performance fees. Instead, EGEM was entitled to receive fees based on acquisitions or dispositions completed by Enerplus. A total of $302,000 was paid to EGEM in respect of the acquisition and disposition fees prior to June 21, 2001, and no acquisition or disposition fees were paid in connection with the merger.

For the nine months ended September 30, 2002, base management fees were $6,291,000. Although the performance fees to be paid in 2002 will be determined following the end of the fiscal year, management has accrued performance fees of $7,280,000 based on the fact that, had the calculation been performed at September 30, 2002, the performance fees for 2002 would be 3.0% of net operating income. The $7,280,000 is an estimate that may increase or decrease throughout the remainder of the year until the performance fees are calculated and finalized following the year ended December 31, 2002. Please read Note 6 to our audited consolidated financial statements for the year ended December 31, 2001 and Note 3 to our unaudited consolidated financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001 for additional information about our management fees.

Reimbursement of General and Administrative Expenses

EGEM is entitled to be reimbursed on a monthly basis for all general and administrative costs incurred by it in performing its duties under the management agreement. Reimbursement includes any costs of capital in respect of carrying any general and administrative costs. EGEM received reimbursement for general and administrative costs of $30,363,000 for the fiscal year ended December 31, 2001 and $24,474,000 for the nine months ended September 30, 2002.

Standard of Care

In exercising its powers and discharging its duties under the management agreement, EGEM is required to act honestly, in good faith and with a view to the best interests of the Fund, its subsidiaries and the unitholders, and is to exercise that degree of care, diligence and skill that a reasonably prudent advisor and manager in respect of the Fund and the Operating Companies and of oil and gas properties in western Canada would exercise in comparable circumstances. EGEM is indemnified by EnerMark, ERC and the Fund against all liabilities and expenses arising from or related in any manner to the management agreement, unless EGEM has not acted in accordance with the foregoing standard of care. The directors, officers, and employees of EGEM are also indemnified by EnerMark, ERC and the Fund unless such persons fail to meet certain standards.

There are no restrictions on the business activities of EGEM with respect to the Canadian oil and gas industry, and there are no provisions which prevent EGEM from rendering services or acting as advisor to any other entity who may have interests similar to our own. However, should a conflict arise between our own interests and EGEM's interests or any entity EGEM is advising, EGEM is required to disclose the conflict, make reasonable efforts to resolve the conflict and act consistently with the standard of care in making any such resolutions.

Term and Termination

The management agreement is in effect for continuous three year terms, with the current term running until June 30, 2005. The term of the agreement may be extended for an additional year by the board of directors of EnerMark prior to March 31 of each year so that the management agreement will always have a three year term.

The management agreement may be terminated by EGEM upon twelve months notice to the Fund and its subsidiaries (i) if the Fund is terminated, (ii) if all or substantially all of the Fund's assets are sold, transferred or otherwise disposed of, or (iii) if the Fund or its subsidiaries default in the performance of a material obligation under the management agreement which is not remedied within 60 days following receipt of notice of the default.

We may terminate the management agreement through a variety of mechanisms including (i) failure to renew the annual extension, (ii) pursuant to an extraordinary resolution of the Fund's unitholders (iii) by the

board of directors of EnerMark upon twelve months notice to EGEM, (iv) if EGEM institutes or consents to the filing of bankruptcy proceedings, seeks relief under bankruptcy laws, appoints or consents to the appointment of a receiver, makes an assignment for the benefit of its creditors, voluntarily suspends the transaction of its usual business or is declared bankrupt or insolvent, or (v) if EGEM defaults in the performance of a material obligation under the management agreement which is not remedied within 60 days following receipt of notice of the default. In these circumstances, the management agreement may be terminated by written notice to EGEM from the trustee or EnerMark.

If the management agreement is terminated as a result of:

- an extraordinary resolution of the unitholders;
- the Fund being terminated pursuant to the terms of the trust indenture;

all, or substantially all, of the Fund's assets being sold, transferred or otherwise disposed of;

failure to renew the annual extension; or

our decision to terminate EGEM's service when we are not entitled to do so,

then EGEM will be paid the base management fee and the performance fees (or the minimum fee where appropriate) owing up to the effective date of termination. EGEM will also be reimbursed for any general and administrative costs owing.

EGEM will also be entitled to "termination costs." These termination costs will be equal to all costs, expenses and obligations that are incurred by EGEM within 90 days following the effective date of the termination of the management agreement, including termination or severance costs associated with terminated personnel and costs associated with cancelled leases or contracts that were entered into by EGEM to service the management agreement.

In addition, EGEM will be paid $40 million if the termination notice is received before December 31, 2003. Alternatively, if the termination notice is received after December 31, 2003, then EGEM will be paid three times the annualized average of the base management fee paid to EGEM in the preceding eight quarters. However, if the management agreement is terminated because we decide not to extend the term of the management agreement or we give 12 months notice of termination, all payment obligations to EGEM will remain the same except that, if the termination notice is received after December 31, 2003, we will owe two times the annualized average of the base management fee paid to EGEM in the preceding eight quarters, which will be payable at the end of the current term or twelve month period, as applicable.

Meanwhile, if EGEM institutes or consents to the filing of bankruptcy proceedings, seeks relief under bankruptcy laws, appoints or consents to the appointment of a receiver, makes an assignment for the benefit of its creditors, voluntarily suspends the transaction of its usual business or is declared bankrupt or insolvent, or if EGEM defaults in the performance of a material obligation under the management agreement which is not remedied within 60 days following receipt of notice of the default, the management agreement may be terminated without the payment of any such fees to EGEM.

Where EGEM reasonably believes, based on a publicly disclosed transaction, that the management agreement might be terminated as a result of a change in control of the Fund, then EnerMark shall place in escrow for EGEM the fees and compensation that it reasonably estimates will be payable, including, without limitation, the maximum permitted amount of termination costs. If the management agreement is terminated, the escrow funds will be released to EGEM and an accounting will take place to determine the balance owed to, or owed by, EGEM. If the management agreement is not terminated, the amounts in escrow will be returned to EnerMark.

Miscellaneous

The management agreement may only be amended in writing by all the parties to the agreement. The board of directors of EnerMark makes all decisions in respect of any such amendment on behalf of the Fund and the Operating Companies. The arrangement between EGEM and Enerplus is not to be construed as a partnership or joint venture between EGEM and Enerplus.

DESCRIPTION OF THE TRUST UNITS

General

The Fund was created, and the trust units are issued, pursuant to a trust indenture among ERC, as settlor, EnerMark and CIBC Mellon Trust Company, as trustee. The Fund is authorized to issue an unlimited number of trust units pursuant to the trust indenture. Each trust unit represents an equal, undivided beneficial ownership interest in the Fund and its assets, and all trust units share equally in all distributions from the Fund and carry equal voting rights at meetings of unitholders. No unitholder will be liable to pay any further calls or assessments in respect of the trust units. No pre-emptive rights attach to the trust units.

The trust indenture provides that the directors of EnerMark may from time to time authorize the creation and issuance of rights, warrants or options to subscribe for trust units or other securities convertible or exchangeable into trust units, on the terms and conditions as the directors of EnerMark may determine. A right, warrant, option or other security is not considered to be a trust unit and a holder of such securities is not considered to be a unitholder. Additionally, the directors of EnerMark may authorize the creation and issuance of debentures, notes and other indebtedness of the Fund on the terms and conditions as the directors of EnerMark may determine.

The trust indenture, among other things, provides for the investment of the Fund's assets, the calculation and payment of distributions to unitholders, the calling of and conduct of business at meetings of unitholders, the appointment and removal of the trustee of the Fund and the redemption of trust units. Among other things, material amendments to the trust indenture, the early termination of the Fund and the sale or transfer of all or substantially all of the property of the Fund require the approval by extraordinary resolution (i.e., $66^2/_3$% of the votes cast) of the unitholders. See " Meetings and Voting" and " Amendments to the Trust Indenture" below.

The following is a summary of certain provisions of the trust indenture. For a complete description, reference should be made to the trust indenture, copies of which may be viewed at the offices of, or obtained from, the trustee. See " Reporting to Unitholders."

The Trustee

The trustee of the Fund is CIBC Mellon Trust Company at 600 The Dome Tower, 333 - 7th Avenue S.W., Calgary, Alberta, Canada T2P 2Z1. The trustee possesses and may exercise all rights, powers and privileges pertaining to the ownership of the Fund's assets to the same extent as an individual or beneficial owner might. Additionally, the trustee is responsible for, among other things, effecting payment of distributions to unitholders, maintaining records and providing timely reports to unitholders and performing functions related to supervision and activities of the Fund. The trustee may delegate any or all of its management or administrative powers as the trustee may in its sole discretion deem necessary to effect the actual administration of the duties of the trustee under the trust indenture. Pursuant to the trust indenture and the management agreement, the trustee has retained EGEM to effect the actual administration of the trustee's duties under the trust indenture. However, the trustee continues to ultimately be responsible for the performance of these duties.

The trustee shall be removed by notice in writing delivered by EnerMark to the trustee if the trustee fails to meet certain criteria stated in the trust indenture or with the approval of at least $66^2/_3$% of the votes cast at a meeting of unitholders called for that purpose. The trustee or any successor may resign upon 60 days notice to EnerMark. Such resignation or removal shall become effective upon the acceptance of appointment by a successor trustee. If the trustee is removed by EnerMark, EnerMark may appoint a successor trustee. If the trustee resigns or is removed by unitholders, its successor may be approved by unitholders. If a successor trustee does not accept its appointment as trustee, a court may appoint the successor trustee.

The trust indenture provides that the trustee shall exercise the powers and discharge the duties of its office honestly, in good faith and in the best interests of the Fund and its unitholders and shall exercise the

degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

The trustee will not be liable for any action taken in good faith in reliance on *prima facie* properly executed documents or for the disposition of monies or securities, nor shall it be liable or responsible in any way for depreciation or loss incurred by reason of the sale of any security, for any inaccuracy in any advice of EGEM or any authorized delegate, for any action or failure to act of EGEM, EnerMark or any authorized delegate, or for any action or failure to act of the trustee that meets the appropriate standard of care. These provisions, however, will not protect the trustee in cases of wilful misfeasance, bad faith, negligence or disregard of its obligations and duties nor will they protect the trustee in any case where the trustee fails to act in accordance with the standard of care described above. The trustee may retain an expert or advisor in connection with the performance of its duties under the trust indenture and may act or refuse to act on the advice of any such expert or advisor without liability. The trustee, where it has met its standard of care, will be indemnified out of the assets of the Fund for any costs, charges, expenses, taxes or other governmental charges imposed upon the trustee in consequence of its performance of its duties but will have no additional recourse against the Fund's unitholders. In addition, the trust indenture contains other customary provisions limiting the liability of the trustee. The trustee is entitled to receive from EnerMark the fees that may be agreed upon in writing by EGEM and the trustee, and is entitled to reimbursement from EnerMark for its expenses incurred in acting as trustee.

Investments of the Fund

The Fund is a limited purpose trust which is restricted to investing in investments or properties described in Section 132(6)(b) of the *Income Tax Act* (Canada) including, without limitation, any investments or property acquired directly or indirectly from the issue of trust units. However, the Fund cannot hold property or investments which would result in the Fund not being either a "unit trust" or a "mutual fund trust", or which would cause the trust units to be foreign property, for the purposes of the *Income Tax Act* (Canada). At present, the sole assets of the Fund are all of the outstanding shares of EnerMark (which owns all of the shares of ERC), unsecured indebtedness issued to the Fund by EnerMark and the 95% and 99% royalty interests issued to the Fund by EnerMark and ERC, respectively. The Fund may invest cash which is not being used immediately for the purposes required in the trust indenture in short term financial instruments guaranteed by a Canadian chartered bank or the federal or a provincial government of Canada.

Distributions of Distributable Income

The Fund makes distributions from its net income and net realized capital gains. It receives income from EnerMark and ERC pursuant to the royalty agreements, as well as from other sources such as principal and interest payments and dividend payments received from our Operating Companies. In determining what amount of its income is distributable, the Fund deducts all taxes (including withholding tax) and all expenses and liabilities of the Fund which are due or accrued and which are chargeable to income. See "Certain Income Tax Considerations Canadian Federal Income Tax Considerations Taxation of Unitholders Not Resident in Canada" for a discussion of the Canadian withholding tax applicable to United States holders. Apart from setting out how distributable income is calculated, the trust indenture provides that the amount of distributable income and net realized capital gains to be paid in any period, and the timing of those distributions, is within the trustee's discretion.

Under the trust indenture, the trustee has the authority to determine the timing and the number of distribution record dates within the year. Under the management agreement, the trustee has delegated this authority to EGEM, subject to the supervision of the board of directors of EnerMark. Currently, the Fund has established a monthly distribution, with the 10th day of each calendar month as a distribution record date and the 20th day of such month as the corresponding distribution payment date. The January 20 payment date is an exception as its corresponding record date is December 31. Under certain circumstances, including where the Fund does not have sufficient cash to pay the full distribution to be made on a distribution payment date, the distribution payable to unitholders may, at the option of the trustee or its delegate, include a distribution of trust units having a value equal to the cash shortfall.

Once a distribution record date has been set, the Fund must declare the amount of distributable income and net realized capital gains, if any, that will be distributed on or before that date and may pay out the distribution on or within 30 days and in the same calendar year as the distribution record date. The trust indenture provides that the trustee may declare payable to the unitholders on a pro rata basis all or any part of the distributable income and net realized capital gains of the Fund for that period ending on the distribution record date to the extent that cash flow was not previously declared payable. The authority to determine the amount of distributable income and net realized capital gains, if any, that will be paid on a given distribution date, and to administer these payments, has been delegated by the trustee to EGEM. On December 31 of each fiscal year, an amount equal to the net income of the Fund for such fiscal year determined in accordance with the *Income Tax Act* (Canada) plus any net realized capital gains of the Fund, to the extent that either is not previously declared payable by the Fund to its unitholders in such fiscal year, will be payable to unitholders immediately prior to the end of that fiscal year. Notwithstanding the foregoing, the Fund may retain that amount of distributable income and net realized capital gains that is determined to be necessary to pay any tax liability of the Fund, and those amounts will not be payable by the Fund to unitholders.

Meetings and Voting

At all meetings of unitholders, each holder is entitled to one vote in respect of each trust unit held. Meetings of the unitholders may be called on not less than 21 days and not more than 50 days notice and may be called at any time by the trustee, and shall be called by the trustee and held annually or upon written request of unitholders holding in the aggregate not less than 20% of the trust units. All activities necessary to organize any such meeting will be undertaken by EGEM on behalf of the trustee.

Unitholders may attend and vote at all meetings of the unitholders either in person or by proxy, and a proxy holder does not have to be a unitholder. Two persons present in person or represented by proxy and representing no less than 5% of the votes attached to all outstanding trust units will constitute a quorum for the transaction of business at such meetings. If a quorum is not present at any such meeting, the meeting will stand adjourned until at least one day later and to such place and time as the chairman of the meeting determines, and the unitholders present in person or by proxy at such adjourned meeting will constitute a quorum for the transaction of any business which might have been dealt with at the original meeting in accordance with the notice calling the original meeting.

Under the trust indenture and other material agreements of Enerplus, unitholders are entitled to nominate all but three of the directors of EnerMark and to nominate the auditors of the Fund. Certain matters, such as the removal or appointment of the trustee, making material amendments to the trust indenture, the termination of the Fund or the sale of all or substantially all of the property of the Fund, must be approved by at least $66^2/_3$% of the votes cast at a meeting of unitholders. Provided due and proper notice to unitholders is given in accordance with the trust indenture, a resolution executed by unitholders holding the requisite number of the outstanding trust units entitled to vote shall have the same effect as if it had been passed by that percentage of votes cast at a duly called meeting of unitholders.

Redemption Right

Each unitholder is entitled to require the Fund to redeem at any time or from time to time, at the demand of and upon written request of the unitholder, all or any part of the trust units registered in the name of the unitholder at a price per trust unit equal to the lesser of:

85% of the market price (as defined in the trust indenture) of the trust units on the principal market on which the trust units are quoted for trading during the 10 day trading period commencing immediately after the date on which the trust units were tendered to the Fund for redemption; and

the closing market price on the principal market on which the trust units are quoted for trading, on the date that the trust units were so tendered for redemption.

The price that unitholders receive for trust units surrendered for redemption during any calendar month will be paid to the unitholder by cheque on the last day of the following month. There is however a

limitation on the amount of cash that the Fund can pay for redemptions. The maximum amount of cash that the Fund can pay for all trust units surrendered for redemption in any calendar month and the preceding calendar month cannot exceed $500,000, although the trustee has the ability to waive this limitation in its discretion. If a unitholder is not entitled to receive a cash payment for trust units surrendered for redemption as a result of such limitations, a unitholder will receive notes or other investments of the Fund, subject to receipt of any applicable regulatory approvals. If at the time that a unitholder surrenders his or her trust units for redemption, the trust units are not listed for trading on the Toronto Stock Exchange or another market which the Trustee considers, in its sole discretion, provides representative fair market value prices for the trust units, or if the normal trading of the trust units has been suspended or halted, the unitholder will receive a price per trust unit equal to 85% of the fair market value as determined by the trustee as at the redemption date.

Management of the Fund

The trust indenture provides the trustee with certain powers and authorities with respect to the Fund and its assets. See " The Trustee" above. Additionally, the trust indenture provides that the trustee may grant or delegate such authority as the trustee may in its sole discretion deem necessary or advisable to effect the actual administration of the Fund. Pursuant to the trust indenture and the management agreement, the trustee has delegated to the directors of EnerMark the supervision of the management and affairs of the Fund, including the responsibility for significant administrative and operational decisions. In particular, the trustee has delegated to the board of directors of EnerMark the responsibility for, among other things, all issuances and offerings of trust units, merger and acquisition activity relating to Enerplus, the amendment of material contracts to which the Fund is a party, borrowings by Enerplus, voting of securities held by the Fund and approval of the Fund's financial statements. Additionally, EGEM has been retained by the Fund and the Operating Companies pursuant to the trust indenture and the management agreement to manage and administer the business and affairs of the Fund and manage the operations, business and affairs of the Operating Companies, subject to the supervision of the directors of EnerMark. See "Management and Corporate Governance Management Agreement."

Termination of the Fund

The unitholders may vote by extraordinary resolution (i.e., $66^2/_3$% of the votes cast) to terminate the Fund at any meeting of unitholders called for that purpose, following which the trustee shall commence to wind up the affairs of the Fund. However, such a vote may be held only if requested in writing by the holders of at least 25% of the trust units or if called by the trustee following the refusal of the trustee to redeem trust units. The quorum requirement for such a meeting is at least 20% of the issued and outstanding trust units represented in person or by proxy.

Upon being required to wind up the affairs of the Fund, the trustee will give notice to the unitholders designating the time at which unitholders may surrender their trust units for cancellation and the date at which the register of the Fund shall be closed.

After the date on which the trustee is required to commence to wind up the affairs of the Fund, the trustee will generally not carry on any activities except for the purpose of winding up the affairs of the Fund and, for this purpose, the trustee shall continue to be vested with and may exercise all or any of the powers conferred upon the trustee under the trust indenture.

Reporting to Unitholders

The accounts of the Fund are audited at least annually by an independent recognized firm of chartered accountants approved by the unitholders, and the financial statements of the Fund, together with the report of the auditors, are mailed by the Fund to unitholders within appropriate regulatory time periods in each calendar year. The fiscal year-end of the Fund is December 31.

The trust indenture provides that a unitholder has the right, upon payment of reasonable costs, to obtain a copy of the trust indenture and the right to inspect and, on payment of reasonable costs, to obtain a list of the registered holders of the trust units for purposes connected with the Fund.

Auditors

The trust indenture generally mirrors certain provisions of the *Business Corporations Act* (Alberta) regarding the appointment, removal and resignation of auditors. The appointment or removal of the Fund's auditors (as well as the appointment of a new auditor upon such removal) must be approved by a majority of the Fund's unitholders. However, if the Fund's auditors resign or are removed by the unitholders without a successor properly appointed, the board of directors of EnerMark has the power to appoint new auditors to fill the vacancy created by the auditors' resignation or removal. The new auditors shall hold office until the next annual meeting of the Fund's unitholders.

Amendments to the Trust Indenture

The trust indenture may be amended from time to time by the trustee, EnerMark and ERC. Material amendments to the trust indenture require approval by at least $66^2/_3$% of the votes cast at a meeting of the unitholders called for that purpose. However, the trustee, EnerMark and ERC may, without the approval of the unitholders, make amendments to the trust indenture for the following purposes:

- ensuring that the Fund will comply with any applicable laws or requirements of any governmental agency or authority of Canada or of any province;

- ensuring that the Fund will maintain its status as a "unit trust" or "mutual fund trust", and not become foreign property, pursuant to the *Income Tax Act* (Canada);

- ensuring that such additional protection is provided for the interests of unitholders as the trustee or the board of directors of EnerMark may consider expedient;

- removing any conflicts or inconsistencies between the provisions of the trust indenture or any supplemental indenture and any prospectus filed with any regulatory or governmental body with respect to the Fund, or any applicable law or regulation of any jurisdiction, if, in the opinion of the trustee, such an amendment will not be detrimental to the interests of the unitholders;

- adding to the provisions of the trust indenture such additional covenants and enforcement provisions as, in the opinion of counsel, are necessary or advisable, or making such provisions not inconsistent with the trust indenture as may be necessary or desirable with respect to matters or questions arising under the trust indenture, provided that the same are not, in the opinion of the trustee, prejudicial to the interests of the unitholders;

- making any modification in the form of the trust unit certificates which does not materially affect the substance thereof;

- modifying any of the provisions of the trust indenture, including relieving EnerMark from any of its obligations, conditions or restrictions, provided that such modification or relief shall be or become operative or effective only if, in the opinion of the trustee, such modification or relief in no way prejudices any of the rights of the unitholders or the trustee; and for any other purpose not inconsistent with the terms of the trust indenture, including the correction or rectification of any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions therein, provided that in the opinion of the trustee, the rights of the trustee and of the unitholders are not prejudiced by those amendments.

DESCRIPTION OF THE ROYALTIES AND THE SUBORDINATED NOTE

The Fund's primary sources of net cash flow are (1) payments received from 95% and 99% net royalty interests issued to the Fund by EnerMark and ERC, respectively, on the production from their oil and natural gas properties, (2) interest and principal payments on debt issued to the Fund by EnerMark, and (3) dividend payments received by the Fund from EnerMark and, indirectly, from ERC. Outlined below is a description of the royalties granted by EnerMark and ERC to the Fund and the subordinated debt issued by EnerMark to the Fund.

Royalty Agreements

Under separate royalty agreements between the Fund and each of EnerMark and ERC, the Operating Companies granted royalties to the Fund equal to 95% (in the case of EnerMark) and 99% (in the case of ERC) of the revenue received in respect of each property in which the Operating Companies presently have an interest or may acquire an interest in the future, net of certain permitted costs and deductions. The ERC royalty payments are also governed by a royalty indenture between ERC and CIBC Mellon Trust Company, which provides that the royalty shall be paid to the holders of royalty units issued by ERC. The Fund is currently the sole holder of all outstanding ERC royalty units. Pursuant to the royalty agreements, each of EnerMark and ERC is required to pay the royalty to the Fund on or about the twentieth day of each month.

The royalty payable to the Fund consists of a 95% or 99% share of the royalty income from EnerMark's or ERC's properties, respectively. In general, royalty income refers to gross production revenues less certain deductions. Gross production revenues essentially consist of:

- cash proceeds from the sale of oil, natural gas and other substances produced from EnerMark's and ERC's properties;
- all grants, incentives, rebates or reimbursements received by EnerMark or ERC in respect of the properties;
- amounts arising out of "take or pay" contracts for oil, natural gas and other products; and
- any other consideration received by EnerMark or ERC as a result of their ownership of the properties with the exception of revenues from the sale, rental or exchange of tangible assets and the proceeds from any unitization or pooling equalization payments relating to tangible assets.

Under certain circumstances, royalty income also consists of the net proceeds received from the sale of properties, although it is anticipated that such proceeds will generally be used to repay debt or purchase additional properties and assets.

In general, the following amounts are deducted from the Operating Companies' gross production revenues in calculating the royalty income:

- operating costs, which consist of all money reasonably expended by EnerMark or ERC in connection with operating, maintaining and utilizing their properties, wells and equipment, including, but not limited to, expenditures related to producing, gathering, treating, storing, compressing, processing and transporting oil, natural gas and other substances, overriding royalties and lessors' royalties, lease and other such payments required to maintain an interest in the properties, and customs and excise duties payable by EnerMark or ERC;
- general and administrative costs, which refer to all expenditures and costs incurred in the management and administration of the royalty and the Operating Companies;

management fees paid to EGEM;

debt service charges, which refer to all fees, interest and principal repayments relating to the borrowing of funds or obtaining of credit, including, in the case of ERC, amounts extended to ERC for the purpose of capital expenditures;

in the case of EnerMark, capital expenditures, which include both expenditures incurred in connection with operations or activities related to the properties as well as acquisition costs that may arise from time to time;

taxes or other charges payable by EnerMark or ERC; and

amounts reserved by EnerMark or ERC for site restorations and abandonments.

In addition to the above deductions, under the ERC royalty agreement the Fund is required to reimburse ERC for 99% of all Crown obligations that it pays in respect of the properties from which production is derived. Under its royalty agreement, EnerMark deducts such costs as operating costs.

Under the royalty agreements, the properties in respect of which the Fund has been granted a royalty interest may be encumbered by security interests given to secure loans by EnerMark and ERC. Such security interests may rank ahead of the royalty interests of the Fund. The EnerMark royalty agreement also provides that the payment of royalty income to the Fund is expressly subordinated to the prior payment in full of EnerMark's debt, as long as the debtor has given appropriate notice or in the context of insolvency or similar proceedings. Further, both EnerMark and ERC have the option at any time to apply any amount of gross production revenues to the repayment of debt.

Pursuant to each royalty agreement, EnerMark and ERC have the right to dispose of properties and the associated royalties if they believe that it is in the best interests of unitholders to do so. The royalty agreements continue in force for as long as EnerMark or ERC has an interest in the properties covered by their respective agreement. The royalty agreements and the royalty indenture may be amended in writing from time to time. All decisions in respect of such amendments are made on behalf of the trustee, the Fund and the Operating Companies by the board of directors of EnerMark.

Subordinated Note

EnerMark has issued an unsecured, subordinated promissory note to the Fund. The subordinated note bears interest at an annual rate of 8% and the principal amount of the note varies as additional funds (generally from the issuance of trust units) are loaned from the Fund to EnerMark and principal repayments are made on the note. The maturity date of the note is June 21, 2015. The payment of principal and interest on the note is subordinated to the prior payment in full of all other debt of EnerMark, other than debt which, by its terms or by operation of law, ranks equal with the subordinated note.

PRINCIPAL UNITHOLDERS

As at October 31, 2002, there were 74,811,975 trust units issued and outstanding.

To the best of the knowledge of management of Enerplus, no person beneficially owns, directly or indirectly, or exercises control or direction over, trust units carrying more than 10% of the voting rights attached to the issued and outstanding trust units.

The directors of EnerMark and officers of EnerMark and EGEM named in this prospectus beneficially own, directly or indirectly, an aggregate of 398,817 trust units, representing approximately 0.5% of the trust units outstanding as of October 31, 2002.

RELATED PARTY TRANSACTIONS AND POTENTIAL CONFLICTS OF INTEREST

Related Party Transactions

EGEM provides management, advisory and administration services to Enerplus on a fee and cost reimbursement basis, pursuant to the management agreement. Additionally, in conjunction with the merger of Enerplus and EnerMark Income Fund on June 21, 2001, EGEM received 172,500 Enerplus trust units with an assigned value of $5,000,000 as a guaranteed minimum performance fee for 2001. The fee was accounted for by the Fund as a cost of the merger. Pursuant to a share purchase agreement related to the merger, EnerMark acquired all of the outstanding common shares of ERC from EGEM resulting in ERC becoming a wholly-owned subsidiary of EnerMark. Consideration for the shares was $2,545,000 and is payable over a five year period ending September 2006. The non-refundable fee advance and acquisition cost of the ERC shares has been included as a cost of the merger. Please read "Management and Corporate Governance Management Agreement", Note 6 to our audited consolidated financial statements for the year ended December 31, 2001 and Note 3 to our unaudited consolidated financial statements at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001, each contained in this prospectus, for additional details regarding the management arrangements between EGEM and Enerplus.

In addition to the transactions described above, in the fall of 2000, Enerplus entered into a financial instrument contract with an indirect subsidiary of El Paso Energy Corporation, the ultimate parent of EGEM, as described in Note 8 to our audited consolidated financial statements for the year ended December 31, 2001 and Note 5 to our unaudited consolidated financial statements at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001.

Potential Conflicts of Interest

There may be situations in which the interests of EGEM or its affiliates will conflict with those of our unitholders. EGEM or its affiliates may acquire oil and natural gas properties on behalf of persons other than the unitholders. EGEM may manage and administer those additional properties, as well as enter into other types of energy-related management and advisory activities. Accordingly, neither EGEM nor its management are required to carry on their full-time activities on behalf of unitholders and, when acting on behalf of others, may at times act in contradiction to or competition with the interests of unitholders. In the event that the interests of EGEM are in conflict with those of our unitholders, EGEM is obliged under the management agreement to make decisions honestly, in good faith and in a manner which treats all interested parties fairly, taking into account the relevant circumstances.

Although EGEM provides advisory and management services to Enerplus, the board of directors of EnerMark supervises the management of the business and affairs of Enerplus and the activities of EGEM under the management agreement, and has responsibility for all significant operational and corporate decisions, including any involving an actual or potential conflict of interest for EGEM. Please read "Management and Corporate Governance."

Properties may not be acquired from officers, directors or shareholders of EGEM or persons not at arm's length with such persons at prices which are greater than fair market value and properties may not be sold to officers, directors or shareholders of EGEM or persons not at arm's length with such persons at prices which are less than fair market value, in each case as established by an opinion of an independent financial advisor. There may be circumstances where certain transactions may also require the preparation of a formal valuation and the affirmative vote of unitholders in accordance with the requirements of Ontario Securities Commission Rule 61-501 Insider Bids, Issuer Bids, Going Private Transactions and Related Party Transactions and similar securities rules.

Circumstances may arise where members of the board of directors of EnerMark serve as directors or officers of corporations which are in competition to the interests of Enerplus. No assurances can be given that opportunities identified by such board members will be provided to Enerplus.

CERTAIN INCOME TAX CONSIDERATIONS

United States Federal Income Tax Considerations for United States Holders

The following is a general description of the material United States federal income tax consequences of the ownership and disposition of our trust units to a United States unitholder (defined below) that holds our trust units as capital assets. This description is for general information purposes only and is based on the United States Internal Revenue Code of 1986, as amended (referred to as the "Code"), Treasury regulations promulgated under the Code, and judicial and administrative interpretations of the Code and those regulations, all as in effect on the date of this prospectus and all of which are subject to change, possibly with retroactive effect. The tax treatment of a United States unitholder may vary depending upon its particular situation. Some holders (including persons that are not United States persons, banks, insurance companies, tax-exempt organizations, financial institutions, persons whose functional currency is not the United States dollar, persons subject to the alternative minimum tax and broker-dealers) may be subject to special rules not discussed below. The discussion below does not address the effect of any state, local or foreign tax law on a United States unitholder. Purchasers of our trust units are advised to consult their own tax advisors with respect to an investment in our trust units.

For purposes of this description, a "United States unitholder" means a beneficial owner of our trust units that is:

- an individual who is a citizen or resident of the United States;
- a partnership, corporation or other entity organized in or under the laws of the United States or of any political subdivision of the United States;
- an estate that is subject to United States federal income taxation without regard to the source of its income; or
- a trust, if a United States court has primary supervision over its administration and one or more United States persons have the authority to control all substantial decisions of the trust, or the trust has made a valid election to be treated as a United States person.

If a partner in a partnership owns trust units, the treatment of a partner will generally depend on the status of the partner and on the activities of the partnership. Partners of a partnership holding trust units should consult their tax advisors.

Classification of the Fund as a Foreign Corporation

Although the Fund is organized as an unincorporated trust under Canadian law, it is classified as a foreign corporation for United States federal income tax purposes under current Treasury regulations. Accordingly, our trust units are treated as shares of stock of a foreign corporation for United States federal tax purposes. The discussion below reflects this classification and uses terminology consistent with this classification, including references to "dividends" and "earnings and profits".

Ownership of Our Trust Units

Dividends

Provided that the Fund is not classified as a passive foreign investment company (as discussed below), United States unitholders will be required to include in gross income as ordinary dividend income the gross amount of distributions they receive for each taxable year, to the extent that the gross amount does not exceed the current or accumulated earnings and profits of the Fund as calculated for United States federal income tax purposes (a "dividend"). This dividend income will not be eligible for the dividends received deduction, which is generally allowed to United States corporate shareholders on dividends received from a domestic corporation. Distributions in excess of our current and accumulated earnings and profits will first be treated as a tax-free return of capital to the extent of the United States unitholder's tax basis in our trust units and will be applied against and reduce that basis on a dollar-for-dollar basis (thereby increasing the amount of gain and decreasing the amount of loss recognized on a subsequent disposition of the trust units).

To the extent that the distribution exceeds the United States unitholder's tax basis, the excess will constitute gain from a sale or exchange of the trust units.

Any tax withheld by Canadian taxing authorities with respect to the dividends on our trust units may, subject to certain limitations, be claimed as a foreign tax credit against a United States unitholder's United States federal income tax liability or may be claimed as a deduction for United States federal income tax purposes. The limitation on foreign taxes eligible for credit is calculated separately with respect to specific classes of income. For this purpose, dividends we distribute with respect to our trust units will be "passive income" or, in the case of certain United States unitholders, "financial services income." Because of the complexity of those limitations, each United States unitholder should consult its own tax advisor with respect to the amount of foreign taxes that may be claimed as a credit.

Taxable dividends with respect to our trust units that are paid in Canadian dollars will be included in the gross income of a United States unitholder as translated into United States dollars calculated by reference to the exchange rate in effect on the day the dividend is received by the unitholder regardless of whether the Canadian dollars are converted into United States dollars at that time. A United States unitholder who receives payment in Canadian dollars and converts Canadian dollars into United States dollars at a conversion rate other than the rate in effect on the day of the dividend distribution may have a foreign currency exchange gain or loss that would be treated as United States source ordinary income or loss. United States unitholders are urged to consult their own tax advisors concerning the United States tax consequences of acquiring, holding and disposing of Canadian dollars.

Sale or Exchange of Our Trust Units

Provided that the Fund is not classified as a passive foreign investment company (as discussed below), a United States unitholder will generally recognize gain or loss upon the sale or exchange of our trust units equal to the difference (if any) between the amount the unitholder realizes on the sale or exchange and its adjusted tax basis in our trust units. Any gain or loss will be capital gain or loss and will be long-term capital gain or loss if the United States unitholder's holding period for the trust units is more than one year at the time of the sale or exchange. Gain or loss, if any, realized by a United States unitholder upon a sale or exchange of our trust units generally will be treated as United States source income for United States foreign tax credit limitation purposes.

In the case of a cash basis United States unitholder who receives Canadian dollars, or another foreign currency, in connection with a sale, exchange or other disposition of our trust units, the amount realized will be based on the United States dollar value of the foreign currency received with respect to the trust units as determined on the settlement date of the sale or exchange. An accrual basis United States unitholder may elect the same treatment required of cash basis taxpayers with respect to a sale or exchange of trust units, provided that the election is applied consistently from year to year. This election may not be changed without the consent of the IRS. If an accrual basis United States unitholder does not elect to be treated as a cash basis taxpayer, that United States unitholder may have a foreign currency gain or loss for United States federal income tax purposes because of differences between the United States dollar value of the currency received prevailing on the date of the sale or exchange of the trust units and the date of payment. This currency gain or loss would be treated as United States source ordinary income or loss and would be in addition to gain or loss, if any, recognized by that United States unitholder on the sale, exchange or other disposition of the trust units.

Passive Foreign Investment Company Considerations

Adverse United States federal income tax consequences would apply to United States unitholders if the Fund were considered a passive foreign investment company for United States federal income tax purposes. A foreign corporation is classified as a passive foreign investment company for each taxable year in which either:

75% or more of its gross income is "passive" income, which includes interest, dividends, certain rents and royalties and certain net gains from the sales of commodities such as oil and natural gas, or

50% or more of the average fair market value of its assets is attributable to assets that produce passive income or are held for the production of passive income.

For purposes of the income test and the asset test, if a foreign corporation owns directly or indirectly at least 25% (by value) of the stock of another corporation, the foreign corporation will be treated as if it held its proportionate share of the assets of the latter corporation and received directly its proportionate share of the income of that latter corporation. Also, for purposes of the income test, passive income does not include any income that is interest, a dividend or a rent or royalty, which is received or accrued from a related person to the extent that amount is properly allocable to the income of the related person that is not passive income. For these purposes, a person is "related" with respect to a foreign corporation if that person controls the foreign corporation or is controlled by the foreign corporation or by the same persons that control the foreign corporation. For these purposes, "control" means ownership, directly or indirectly, of stock possessing more than 50% of the total voting power of all classes of stock entitled to vote or of the total value of stock of a corporation.

The Code and applicable Treasury regulations exclude gains from transactions in commodities from the definition of passive income if (i) the gains arise from the sale of the commodity in the active conduct of a commodities business as a producer, processor, merchant or handler of the commodity and (ii) substantially all of the foreign corporation's business is as an active producer, processor, merchant or handler of the commodity. It is unclear under these rules whether certain of the commodities income of the Fund will be treated as nonpassive income. In addition, applicable Treasury regulations interpret "substantially all" to mean that 85 percent or more of the foreign corporation's total gross receipts must be gross receipts from sales in the active conduct of a commodities business as a producer, processor, merchant or handler of commodities. The Fund believes that it currently satisfies this requirement, but no assurance exists that it will continue to do so in the future.

The application of the passive foreign investment company provisions to us is uncertain, and we may be a passive foreign investment company for the 2002 taxable year and in subsequent taxable years. Under the Code, if the Fund or any of the operating subsidiaries were considered to be a passive foreign investment company in any taxable year that a United States unitholder holds our trust units, the Fund and such operating subsidiary, as applicable, would be considered passive foreign investment companies for all taxable years that such unitholder held our trust units after the first taxable year that the Fund or any of the operating subsidiaries were considered to be a passive foreign investment company.

If the Fund were classified as a passive foreign investment company, a United States unitholder would generally be subject to special rules with respect to any excess distribution (defined below) or any gain realized upon the sale or other disposition of our trust units. Under these rules:

- the excess distribution or gain would be allocated ratably over the United States unitholder's holding period;
- the amount allocated to the current taxable year and any year prior to the first year in which we were a passive foreign investment company would be taxed as ordinary income in the current year;
- the amount allocated to each of the other taxable years would be subject to tax at the highest rate of tax in effect for the applicable class of taxpayer for that year; and
- an interest charge for the deemed deferral benefit would be imposed with respect to the resulting tax attributable to each of the other taxable years.

An "excess distribution" in general is any distribution on our trust units received in a taxable year by a United States unitholder that is greater than 125% of the average annual distributions received by that unitholder in the three preceding taxable years or, if shorter, that unitholder's holding period for our trust units. A distribution would not be treated as an excess distribution for the taxable year during which a United States unitholder's holding period for our trust units begins.

For purposes of the passive foreign investment company rules, if the Fund were classified as a passive foreign investment company, United States unitholders would be deemed to own an interest in any foreign passive investment company that is considered as being owned directly or indirectly by the Fund.

Accordingly, if the Fund were considered a passive foreign investment company and any of the operating subsidiaries also were considered a passive foreign investment company, United States unitholders would be deemed to own an interest in such entities. Provided this is the case, United States unitholders would be subject to the excess distribution rules as described above with respect to any distribution by an operating subsidiary to the Fund and gains from any disposition of stock of an operating subsidiary by the Fund.

United States unitholders will not be able to make a "qualified electing fund", or "QEF", election or, with respect to the Fund's operating subsidiaries that were considered to be passive foreign investment companies, a "mark-to-market" election to protect themselves from these potential adverse tax consequences if the Fund were ultimately determined to be a passive foreign investment company. If the Fund were determined to be a passive foreign investment company, a United States unitholder would be required to file Internal Revenue Service Form 8621 for each year in which the unitholder holds trust units.

UNITED STATES UNITHOLDERS ARE STRONGLY URGED TO CONSULT THEIR OWN TAX ADVISORS REGARDING OUR POSSIBLE CLASSIFICATION AS A PASSIVE FOREIGN INVESTMENT COMPANY AND THE ADVERSE TAX CONSEQUENCES THAT WOULD RESULT FROM SUCH CLASSIFICATION.

Tax-Exempt Organization and Mutual Fund Investors

Qualified pension and profit-sharing plans, IRAs, educational institutions and other exempt investors are generally exempt from United States federal income tax except to the extent that they have unrelated business taxable income ("UBTI"). UBTI is generally income from a trade or business that is unrelated to the activities of the tax-exempt entity or income from a debt-financed investment. Because the Fund is considered a corporation for United States federal income tax purposes, tax-exempt United States unitholders will not be subject to United States federal income tax from their ownership and disposition of trust units unless the tax-exempt's investment in trust units is debt-financed. Because, generally, no United States federal income tax will be imposed with respect to a tax exempt's ownership and disposition of Trust units, a tax-exempt owner will receive no foreign tax credit benefit for Canadian taxes withheld with respect to distributions from the Fund. Unless the tax-exempt United States unitholder's investment is debt-financed, the passive foreign investment company adverse tax rules should not apply to a tax-exempt unitholder's investment in trust units. If a tax-exempt United States unitholder's investment is debt-financed, the unitholder should consult its tax advisor regarding the possible implication of the passive foreign investment company rules discussed above.

A regulated investment company or "mutual fund" is required to derive 90% or more of its gross income from interest, dividends and gains from the sale of stocks or securities or foreign currency or specified related sources. At least 50% of the value of a mutual fund's total assets must consist of cash, cash items, securities of other mutual funds and a limited amount of other securities. Ownership of trust units by a mutual fund will generate qualifying income to the mutual fund and the trust units will be treated as a qualifying asset. Mutual fund unitholders should, however, consult their tax advisors regarding the consequences to the mutual fund if the Fund were treated as a passive foreign investment company, including the application of the passive foreign investment company mark-to-market elections.

United States Information Reporting and Backup Withholding

Dividends on our trust units paid within the United States or through some United States -related financial intermediaries are subject to information reporting and may be subject to backup withholding, currently at a 30% rate, unless the unitholder is a corporation or other exempt recipient or provides a taxpayer identification number and complies with certain certification requirements. Information reporting requirements and backup withholding may also apply to the cash proceeds of a sale of our trust units.

Backup withholding is not an additional tax. Amounts withheld under the backup withholding rules may be credited against a unitholder's United States federal income tax liability, and a unitholder may obtain a refund of any excess amounts withheld under the backup withholding rules by filing the appropriate claim for refund with the IRS.

Canadian Federal Income Tax Considerations

In the opinion of Blake, Cassels & Graydon LLP and Burnet, Duckworth & Palmer LLP (collectively, "Counsel"), the following is a fair and adequate general summary of the principal Canadian federal income tax consequences applicable to purchasers of trust units issued hereunder. This summary is only applicable to persons who, for the purposes of the *Income Tax Act* (Canada) (the "Tax Act") and at all relevant times will hold the trust units as capital property and deal at arm's length with the Fund and the underwriters. This summary is not applicable to partnerships, "financial institutions" as defined in section 142.2 of the Tax Act, "specified financial institutions" as defined in the Tax Act or persons in which an interest would be a "tax shelter" or a "tax shelter investment" for the purposes of the Tax Act. Trust units will generally be considered to be held as capital property unless the holders of trust units (a "Unitholder") is a trader or dealer in securities or is engaged in an adventure in the nature of trade with respect to the trust units. Certain Unitholders, other than traders or dealers in securities, whose trust units might not otherwise qualify as capital property, may be entitled to so qualify their trust units by making the lifetime election relating to dispositions of Canadian securities. Unitholders interested in making this election should consult their tax advisors.

This summary is based upon the provisions of the Tax Act and the Income Tax Regulations (the "Regulations"), all specific proposals to amend the Tax Act and Regulations that have been publicly announced prior to the date hereof and Counsel's understanding of the current administrative practices and policies of the Canada Customs and Revenue Agency ("CCRA"). Except as specifically noted herein, this summary does not otherwise take into account proposed or possible changes in law whether by judicial or legislative action. This summary does not consider the income tax legislation of any of the provinces of Canada, nor does it consider the income tax legislation of any foreign country.

This summary is of a general nature only and is not intended to constitute income tax advice to any prospective purchasers of the trust units. The tax considerations for a specific holder will depend on such holder's particular circumstances and, therefore, prospective purchasers are urged to consult their own tax advisors as to their particular income tax situations.

Status of the Fund

EnerMark, ERC and EGEM have confirmed that the Fund currently qualifies as a "mutual fund trust" for the purposes of the Tax Act and this summary assumes that the Fund will continue to so qualify. Continued qualification requires certain conditions under the Tax Act be maintained. EGEM and the Fund intend to ensure that these conditions will continue to be satisfied and the Fund will continue to so qualify, but if the Fund ceases to qualify, the income tax considerations associated with the trust units will be materially different than described below.

Taxation of the Fund

The Fund is subject to taxation in each taxation year on its income for that year including net realized taxable capital gains, dividends, accrued interest and all amounts received in respect of the royalties the Fund holds on the oil and natural gas properties of EnerMark and ERC (the "Royalties"), including amounts paid by it to ERC in respect of reimbursed Crown charges. Costs incurred in the issuance of trust units may generally be deducted by the Fund on a five year, straight line basis. The Fund will also be entitled to deduct reasonable current expenses incurred in its ongoing operations and a resource allowance in each taxation year generally equal to 25% of the Fund's "adjusted resource profits" which are calculated in accordance with the Regulations.

The Fund may deduct, in computing its income from all sources for a taxation year, an amount not exceeding 10%, on a declining balance basis, of its cumulative Canadian oil and gas property expense ("COGPE") account at the end of that year. Where, as a result of a sale of a property by EnerMark or ERC and the extinguishment of the Royalty with respect thereto, proceeds of disposition become receivable by the Fund in a taxation year, the amount of such proceeds ("Royalty Disposition Proceeds") will be required to be deducted from the balance of the Fund's cumulative COGPE account otherwise determined. If all or a portion of the Royalty Disposition Proceeds receivable in a taxation year are utilized in that year by the

Fund to acquire additional royalty interests in respect of one or more Canadian resource properties, the amount so utilized will be added, in that year, to its cumulative COGPE account. If, after taking into account all additions and deductions for any taxation year, the balance of the cumulative COGPE account of the Fund is negative at the end of such taxation year, the negative balance will be included in the income of the Fund for such year.

The Tax Act requires the Fund to compute its income or loss for a taxation year as though it were an individual resident in Canada. To the extent that the Fund has any taxable income for a taxation year after the inclusions and deductions outlined above, the Fund will be permitted to deduct the portion of such income which is paid or payable by it to the Unitholders in such year.

Under the trust indenture, an amount equal to all of the royalty, interest and dividend income of the Fund for each year, together with the taxable and non-taxable portion of any capital gains realized by the Fund in the year (net of the Fund's expenses and amounts, if any, required to be retained to pay any tax liability of the Fund) ("Net Income") will be payable to the holders of the trust units. Subject to the exceptions described below, all amounts payable to the holders of trust units shall be paid by way of cash distributions.

Under the trust indenture, Net Income of the Fund may be used to finance cash redemptions of trust units, and income so utilized will not be payable to holders of the trust units by way of cash distributions. In such circumstances, Net Income will be payable to holders of trust units in the form of additional trust units ("Reinvested Trust Units"). Moreover, under the Trust Indenture, the Fund may, in certain circumstances, issue Redemption Notes to finance the redemption of trust units rather than distribute investments of the Fund. An amount equal to the income of the Fund utilized for the purposes of making interest and principal payments under the Redemption Notes may also be payable to the holders of the trust units in the form of Reinvested Trust Units rather than by way of cash distributions.

EnerMark, ERC and EGEM have confirmed that, for purposes of the Tax Act, the Fund intends to deduct, in computing its income, the full amount available for deduction in each year to the extent of its income for the year otherwise determined. As a result of such deduction from income, it is expected that the Fund will not be liable for any material tax under the Tax Act. However, no assurances can be given in this regard.

Taxation of Unitholders Resident in Canada

Income of a Unitholder from the trust units will be considered to be income from property that is a trust and not resource income (or resource profits for resource allowance purposes) or interest income for the purposes of the Tax Act. Any loss of the Fund for the purposes of the Tax Act cannot be allocated to, and treated as a loss of, a Unitholder.

A Unitholder will generally be required to include in computing its income for a particular taxation year the portion of the net income of the Fund for a taxation year that is paid or payable to the Unitholder in that particular taxation year, or to which a Unitholder is entitled to enforce payment, including any such amount which is payable in Reinvested Trust Units.

Provided that appropriate designations are made by the Fund, such portions of its net taxable capital gains and taxable dividends as are paid or payable to a Unitholder will effectively retain their character as taxable capital gains and taxable dividends, respectively, and shall be treated as such in the hands of the Unitholder for purposes of the Tax Act, including the dividend gross-up and tax credit provisions applicable to individuals and the provisions of Part IV which are applicable in respect of amounts received by certain corporations.

The non-taxable portion of net realized capital gains (being one half thereof) of the Fund that is paid or payable to a Unitholder in a year will not be included in computing the Unitholder's income for the year. Any other amount in excess of the taxable income of the Fund that is paid or payable by the Fund to a Unitholder in a year should not generally be included in the Unitholder's income for the year. However, any such amount which becomes payable to a Unitholder, other than as proceeds of disposition of trust units or fractions thereof, will be applied to reduce the adjusted cost base of the trust units held by such Unitholder,

except to the extent that the amount either was included in the income of the Unitholder or was the Unitholder's share of the non-taxable portion of the net capital gains of the Fund, the taxable portion of which was designated by the Fund in respect of the Unitholder. To the extent that the adjusted cost base of a trust unit is less than zero, the negative amount will be deemed to be a capital gain of a Unitholder from the disposition of the trust unit in the year in which the negative amount arises, and the adjusted cost base of the trust unit at the commencement of the subsequent year will be nil.

The initial cost to a holder of a trust unit issued hereunder will be equal to the subscription price of such trust unit. Reinvested Trust Units issued to a Unitholder in lieu of a cash distribution of royalty and interest income will have an initial cost equal to the amount of such royalty and interest income. Each time a holder acquires additional trust units, the initial cost of those trust units will be averaged with the adjusted cost base of all other trust units held by the Unitholder in order to determine the respective adjusted cost base of each such trust unit.

The disposition or deemed disposition by a Unitholder of a trust unit, whether on redemption or otherwise, will generally result in the Unitholder realizing a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition (excluding any amount payable by the Fund which represents an amount that must otherwise be included in the Unitholder's income as described above) are greater (or less) than the aggregate of the Unitholder's adjusted cost base of the trust unit and any reasonable costs of disposition.

Under the Tax Act, one half of any capital gain realized by a Unitholder upon the disposition of a trust unit and the entire amount of any net taxable capital gains designated by the Fund in respect of the Unitholder will be included in the Unitholder's income under the Tax Act for the year of disposition or designation, as the case may be, as a taxable capital gain. Subject to certain specific rules in the Tax Act, one half of any capital loss realized on the disposition of a trust unit may be deducted against any taxable capital gains realized by the Unitholder in the year of disposition, in the three preceding taxation years or in any subsequent taxation year.

Taxable capital gains realized by a unitholder that is an individual or a trust, other than certain types of trusts, may give rise to alternative minimum tax depending on the unitholder's circumstances.

A unitholder that is a "Canadian-controlled private corporation" (as defined in the Tax Act) may be liable to pay an additional refundable tax of $6^{2}/_{3}$% on certain investment income, including taxable capital gains. The $6^{2}/_{3}$% tax is to be added to the Canadian-controlled private corporation's refundable dividend tax on hand account and will be eligible for refund at a rate of $1 for every $3 of dividends paid by the Canadian-controlled private corporation.

Taxation of Unitholders Not Resident in Canada

Where the Fund makes distributions to a Unitholder who is not resident in Canada for purposes of the Tax Act, the same considerations as those discussed above with respect to a Unitholder who is resident in Canada will apply, except that any distribution of income of the Fund to a Unitholder not resident in Canada will be subject to Canadian withholding tax at the rate of 25%, unless such rate is reduced under the provisions of a tax treaty between Canada and the Unitholder's jurisdiction of residence. For example, residents of the United States will be entitled to have the rate of withholding reduced to 15% of the amount of any distribution of income. To the extent that Canadian withholding tax is applied to the non-taxable portion of a distribution, unitholders (or their agent) may apply for a refund of such Canadian withholding tax by filing the CCRA's Form NR7-R "Application for Refund of Non-Resident Tax Withheld" no later than two years after the end of the calendar year in which the Fund has paid the distribution. Some, but not all, entities that are exempt from tax in the United States may be entitled to have the rate of Canadian withholding tax reduced to nil pursuant to paragraph 1 of Article XXI of the Canada United States Tax Convention if such entity provides the Fund or its agent with the appropriate Certificate of Exemption issued by the CCRA. In addition, taxable dividends received by the Fund and paid to a Unitholder who is not resident in Canada will not retain their character as dividends and will be treated as trust income for Canadian withholding tax purposes.

A disposition or deemed disposition of a trust unit, whether on redemption, by virtue of capital distributions in excess of a Unitholder's adjusted cost base or otherwise, will not give rise to any capital gain subject to tax under the Tax Act to Unitholders who, for purposes of the Tax Act, are neither resident nor deemed to be resident in Canada, do not carry on an insurance business in Canada, hold their trust units as capital property, neither use nor hold their trust units in the course of carrying on business in Canada, and deal at arm's length with the Fund within the meaning of the Tax Act, provided that their trust units do not constitute "taxable Canadian property" under the Tax Act. Trust units of a Unitholder will not generally be considered to be "taxable Canadian property" unless either: (i) at any time during the period of five years immediately preceding the disposition of trust units by such Unitholder, not less than 25% of the issued trust units (taking into account any rights to acquire trust units) were owned by the Unitholder, by persons with whom the Unitholder did not deal at arm's length or by any combination thereof; (ii) the Fund ceases to qualify as a mutual fund trust; or (iii) the Unitholder's trust units are otherwise deemed to be taxable Canadian property. A Unitholder who is not resident in Canada will generally compute the adjusted cost base of his or her trust units under the same rules as apply to residents of Canada.

CERTAIN ERISA CONSIDERATIONS

The U.S. Employee Retirement Income Security Act of 1974, as amended ("ERISA") and Section 4975 of the U.S. Internal Revenue Code of 1986, as amended (the "Code") impose certain requirements on (i) employee benefit plans (as defined in Section 3(3) of ERISA), (ii) plans described in Section 4975(e)(1) of the Code and (iii) entities whose underlying assets include plan assets by reason of a plan's investment in the entity (collectively, "Plans").

In accordance with ERISA's general fiduciary standards, before investing in any trust units, a fiduciary of a Plan that is subject to ERISA (an "ERISA Plan") should determine whether such an investment is permitted under the governing Plan instruments and is appropriate for the Plan in view of the Plan's overall investment policy and the composition and diversification of its portfolio. Other provisions of ERISA and the Code prohibit certain transactions between an ERISA Plan or a Plan described in Section 4975(e)(1) of the Code and persons who have certain specified relationships to such Plan ("parties in interest" within the meaning of ERISA or "disqualified persons" within the meaning of the Code). Thus, a fiduciary of such a Plan considering an investment in trust units should also consider whether such an investment would constitute or give rise to a prohibited transaction under ERISA or the Code.

In determining whether an investment in trust units would satisfy the fiduciary requirements of ERISA or result in a prohibited transaction, the fiduciary should consider whether the assets of the Fund will be considered "plan assets" within the meaning of United States Department of Labor Regulation 29 C.F.R. § 2510.3-101 (the "Plan Asset Regulations"). Under the Plan Asset Regulations, an entity's assets would not be considered to be "plan assets" if the equity interests acquired by a Plan are (1) held by 100 or more investors independent of the issuer and each other, (2) freely transferable, and (3) registered under the U.S. federal securities laws. The Fund's assets should not be considered "plan assets" under these regulations because the trust units will satisfy the three requirements stated above.

Plan fiduciaries contemplating a purchase of the trust units should consult with their own counsel regarding the consequences of ERISA and the Code in light of the serious penalties imposed on persons who violate their fiduciary obligations or engage in prohibited transactions.

UNDERWRITING

CIBC World Markets Inc. and Salomon Smith Barney Inc. are acting as joint bookrunning managers of the offering and are acting as representatives of the underwriters named below.

Subject to the terms and conditions stated in the underwriting agreement dated the date of this prospectus, each underwriter named below has agreed to purchase, and we have agreed to sell to that underwriter, the number of trust units set forth opposite the underwriter's name.

Underwriter	Number of Trust Units
CIBC World Markets Inc.	1,400,000
Salomon Smith Barney Inc.	1,400,000
RBC Dominion Securities Inc.	840,000
BMO Nesbitt Burns Inc.	630,000
Lehman Brothers Inc.	630,000
Scotia Capital Inc.	630,000
UBS Warburg LLC	630,000
National Bank Financial Inc.	280,000
TD Securities Inc.	280,000
Canaccord Capital Corporation	140,000
Raymond James Ltd.	140,000
Total	7,000,000

The underwriting agreement provides that the obligations of the underwriters to purchase the trust units included in this offering are subject to approval of legal matters by counsel and to other conditions. The obligations of the underwriters under the underwriting agreement are several and may be terminated at their discretion on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. The underwriters are obligated to purchase all the trust units (other than those covered by the over-allotment option described below) if they purchase any of the trust units.

This offering is being made concurrently in the United States and in all of the provinces of Canada pursuant to the multi-jurisdictional disclosure system implemented by the securities regulatory authorities in the United States and Canada. The trust units will be offered in the United States and Canada through the underwriters either directly or through their respective U.S. or Canadian registered broker-dealer affiliates. Subject to applicable law, the underwriters may offer the trust units outside of the United States and Canada.

The underwriters propose to offer some of the trust units directly to the public at the public offering price set forth on the cover page of this prospectus and some of the trust units to dealers at the public offering price less a concession not to exceed $0.78 per trust unit offered in Canada and US$0.50 per trust unit offered in the United States. The underwriters may allow, and dealers may re-allow, a concession not to exceed US$0.10 per trust unit offered in the United States on sales to other dealers. If all of the trust units are not sold at the initial offering price, the representatives may change the public offering price and the other selling terms.

We have granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to 1,050,000 additional trust units at the public offering price less the underwriting discount. The underwriters may exercise the option solely for the purpose of covering over-allotments, if any, in connection with this offering. To the extent the option is exercised, each underwriter must purchase a number of additional trust units approximately proportionate to that underwriter's initial purchase commitment.

We have agreed that, for a period of 90 days from the date of this prospectus, we will not, without the prior written consent of CIBC World Markets Inc. and Salomon Smith Barney Inc., dispose of or hedge any trust units or any securities convertible or exchangeable for our trust units, except in connection with (i) the grant or exercise of options or rights pursuant to our trust unit option plan and trust unit rights incentive plan, (ii) the issuance of trust units pursuant to our distribution reinvestment and optional trust

unit purchase plan or (iii) the direct issuance of trust units pursuant to one or more acquisitions whose purchase prices do not, in the aggregate, exceed $400 million. Our officers and directors and some of our other unitholders have agreed that, for a period of 60 days after the date of this prospectus, they will not, without the prior written consent of CIBC World Markets Inc. and Salomon Smith Barney Inc., dispose of or hedge any trust units or any securities convertible into or exchangeable for our trust units, other than (i) the sale or transfer of trust units in connection with the exercise of a currently outstanding warrant, option or right that would otherwise expire prior to 60 days after the date of the prospectus or (ii) trust units disposed of as bona fide gifts approved by CIBC World Markets Inc. and Salomon Smith Barney Inc.

Our currently issued and outstanding trust units are listed on the Toronto Stock Exchange under the symbol "ERF.UN" and on the New York Stock Exchange under the symbol "ERF." The Toronto Stock Exchange has conditionally approved the listing of the trust units offered under this prospectus, subject to Enerplus fulfilling all of the requirements of that exchange on or before February 12, 2003. The New York Stock Exchange has authorized the listing of the trust units offered under this prospectus upon receipt of official notice of issuance of the trust units.

The following table shows the underwriting discounts that we are to pay to the underwriters in connection with this offering. These amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase additional trust units.

	Paid by Enerplus Resources Fund							
	No Exercise				Full Exercise			
Per Trust Unit	Cdn$	1.30	(US$	0.827)	Cdn$	1.30	(US$	0.827)
Total	Cdn$	9,100,000	(US$	5,789,000)	Cdn$	10,465,000	(US$	6,657,350)

In connection with the offering of trust units, CIBC World Markets Inc. and Salomon Smith Barney Inc., on behalf of the underwriters, may purchase and sell trust units in the open market. These transactions may include short sales, syndicate covering transactions and stabilizing transactions. Short sales involve syndicate sales of trust units in excess of the number of trust units to be purchased by the underwriters in the offering, which creates a syndicate short position. "Covered" short sales are sales of trust units made in an amount up to the number of trust units represented by the underwriters' over-allotment option. In determining the source of trust units to close out the covered syndicate short position, the underwriters will consider, among other things, the price of trust units available for purchase in the open market as compared to the price at which they may purchase trust units through the over-allotment option. Transactions to close out the covered syndicate short involve either purchases of the trust units in the open market after the distribution has been completed or the exercise of the over-allotment option. The underwriters may also make "naked" short sales of trust units in excess of the over-allotment option. The underwriters must close out any naked short position by purchasing trust units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the trust units in the open market after pricing that could adversely affect investors who purchase in the offering. Stabilizing transactions consist of bids for or purchases of trust units in the open market while the offering is in progress.

The underwriters also may impose a penalty bid. Penalty bids permit the underwriters to reclaim a selling concession from a syndicate member when CIBC World Markets Inc. and Salomon Smith Barney Inc. repurchase trust units originally sold by that syndicate member in order to cover syndicate short positions or make stabilizing purchases.

In accordance with policy statements of the Commission des valeurs mobilières du Québec and the Ontario Securities Commission, the underwriters in Canada may not, throughout the period of distribution, bid for or purchase trust units. Such restriction is subject to certain exceptions, provided that the bid or purchase was not engaged in for the purpose of creating actual or apparent active trading in, or raising the price of the trust units, including: (1) a bid or purchase permitted under the by-laws and rules of the Toronto Stock Exchange relating to market stabilization and passive market making activities; and (2) a bid or purchase made for and on behalf of a customer where the order was not solicited during the period of the distribution. Under the first mentioned exemption, in connection with this offering, the underwriters may over-allot or effect transactions which stabilize or maintain the market price of the trust units at a level other

than that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

Any of these activities may have the effect of preventing or retarding a decline in the market price of the trust units. They may also cause the price of the trust units to be higher than the price that would otherwise exist in the open market in the absence of these transactions. The underwriters may conduct these transactions on the Toronto Stock Exchange, the New York Stock Exchange or in the over-the-counter market, or otherwise. If the underwriters commence any of these transactions, they may discontinue them at any time.

We estimate that our portion of the total expenses of this offering will be $2 million.

Because more than 10% of the proceeds of this offering, not including underwriting compensation, will be received by entities who are affiliated with National Association of Securities Dealers, Inc. members who are participating in this offering, this offering is being conducted in compliance with the NASD Conduct Rule 2710(c)(8). Pursuant to that rule, the appointment of a qualified independent underwriter is not necessary in connection with this offering, as a bona fide independent market (as defined in NASD Conduct Rules) exists in the trust units. Because the NASD views the trusts units offered hereby as interests in a direct participation program, the offering is being made in compliance with Rule 2810 of the NASD Conduct Rules.

Each of CIBC World Markets Inc., Salomon Smith Barney Inc., RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., Scotia Capital Inc., National Bank Financial Inc. and TD Securities Inc. is affiliated with a Canadian chartered bank which is a lender to Enerplus. Please read "Management's Discussion and Analysis of Operating Results and Financial Condition Liquidity and Capital Resources" and Note 4 to our unaudited consolidated financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001, included in this prospectus, for a description of our bank facilities. As a result, we may be considered to be a connected issuer of these underwriters under applicable Canadian securities laws. As of September 30, 2002, we were indebted to the lenders under our credit facilities in the amount of approximately $94 million. We are in compliance with all material terms of the agreements governing our credit facilities. Our credit facilities are unsecured and our financial position has not changed substantially since indebtedness under the credit facilities was incurred. The decision to distribute the trust units offered under this prospectus and the determination of the terms of the distribution were made through negotiations between EnerMark and EGEM, on our behalf, and the underwriters. The banks affiliated with the underwriters did not have any involvement in such decision or determination but have been advised of this issuance and its terms. As a consequence of this offering, CIBC World Markets Inc., Salomon Smith Barney Inc., RBC Dominion Securities Inc., BMO Nesbitt Burns Inc., Scotia Capital Inc., National Bank Financial Inc. and TD Securities Inc. will receive their share of the underwriters' discounts and commissions and the banks affiliated with those underwriters will receive certain proceeds of this offering from us as repayment of our outstanding indebtedness. Please read "Use of Proceeds."

The offering price for the trust units offered under this prospectus was determined by negotiation between EnerMark and EGEM, on behalf of Enerplus, and the underwriters.

The underwriters have performed investment banking and advisory services for us from time to time for which they have received customary fees and expenses. The underwriters may, from time to time, engage in transactions with and perform services for us in the ordinary course of their business.

A prospectus in electronic format may be made available on the websites maintained by one or more of the underwriters. The representatives may agree to allocate a number of trust units to underwriters for sale to their online brokerage account holders. The representatives will allocate trust units to underwriters that may make Internet distributions on the same basis as other allocations. In addition, trust units may be sold by the underwriters to securities dealers who resell trust units to online brokerage account holders.

We have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act of 1933, as amended, and Canadian securities laws or to contribute to payments the underwriters may be required to make because of any of those liabilities.

LEGAL MATTERS

Certain legal matters in connection with the issuance of the trust units offered by this prospectus will be passed upon on behalf of Enerplus by Blake, Cassels & Graydon LLP, Calgary, Alberta, with respect to matters of Canadian law, and Andrews & Kurth L.L.P., Houston, Texas, with respect to matters of United States law. Certain legal matters in connection with the issuance of trust units offered by this prospectus will be passed upon on behalf of the underwriters by Burnet, Duckworth & Palmer LLP, Calgary, Alberta, with respect to matters of Canadian law, and Shearman & Sterling, Toronto, Ontario, with respect to matters of United States law. The partners and associates, as a group, of each of Blake, Cassels & Graydon LLP and Burnet, Duckworth & Palmer LLP own, directly or indirectly, less than 1% of the outstanding trust units.

EXPERTS

Our consolidated financial statements as at and for the year ended December 31, 2001 included and incorporated by reference in this prospectus have been audited by Deloitte & Touche LLP, independent auditors, as stated in their report which is included and incorporated herein, and have been so included and incorporated in reliance upon the report of such firm given upon their authority as experts in accounting and auditing. As of the date hereof, the partners of Deloitte & Touche LLP, as a group, do not beneficially own, directly or indirectly, any trust units of the Fund.

Our consolidated financial statements included and incorporated by reference in this prospectus for the fiscal years ending December 31, 2000 and 1999 have been audited by PricewaterhouseCoopers LLP, Chartered Accountants, as set forth in their report appearing in this prospectus, and are included in reliance upon such report given on the authority of such firm as experts in accounting and auditing.

Reserve estimates contained in, and incorporated by reference into, this prospectus are based upon separate reports prepared by Sproule Associates Limited with respect to our reserves as of January 1, 2002 and with respect to a portion of Celsius' reserves as of January 1, 2002. Other reserve estimates contained in this prospectus are based on a report prepared by Gilbert Laustsen Jung Associates Ltd. with respect to a portion of Celsius' reserves as of January 1, 2002. As of the date hereof, the partners, as a group, of Sproule Associates Limited own, directly or indirectly, less than 1% of the outstanding trust units.

The financial statements of pre-merger Enerplus incorporated into this prospectus for the fiscal years ended December 31, 2000, 1999 and 1998 have been audited by Arthur Andersen LLP, as indicated in their report with respect thereto and are incorporated hereto in reliance upon the authority of said firm as experts in accounting and auditing in giving said reports. We are not able to obtain the consent of Arthur Andersen LLP to the incorporation of their report into this prospectus. As a result, you will not be able to recover against Arthur Andersen LLP under Canadian securities laws and under Section 11 of the Securities Act of 1933, as amended, for any untrue statements of material fact contained in the financial statements audited by Arthur Andersen LLP or any omissions to state a material fact required to be stated therein. Please read "Documents Incorporated by Reference" and "Risk Factors Risks Relating to Arthur Andersen LLP."

TRANSFER AGENT AND REGISTRAR

CIBC Mellon Trust Company, at its principal offices in Calgary, Alberta, Toronto, Ontario, and Montréal, Québec is transfer agent and registrar for the trust units. Mellon Investor Services LLC in New York, New York is co-transfer agent for the trust units.

DOCUMENTS INCORPORATED BY REFERENCE

Under the multijurisdictional disclosure system adopted by the United States and the provinces of Canada, the SEC and the Canadian provincial securities commissions allow us to "incorporate by reference" in this prospectus information that we file with them, which means that we can disclose important information to you by referring you to these documents. Accordingly certain documents have been incorporated by reference in this prospectus from documents furnished to the SEC and filed with securities commissions or similar authorities in Canada.

Information has been incorporated by reference in this prospectus from documents filed with securities commissions or similar authorities in Canada. You can obtain copies of the documents incorporated herein by reference without charge from the Corporate Secretary of EGEM, at The Dome Tower, Suite 3000, 333 - 7th Avenue S.W., Calgary, Alberta, T2P 2Z1, telephone (403) 298-2200 or by accessing the Fund's disclosure documents available through the internet on the Canadian System for Electronic Document Analysis and Retrieval (SEDAR) which can be accessed at www.sedar.com. For the purposes of the Province of Québec, this simplified prospectus contains information to be completed by consulting the permanent information record. A copy of the permanent information record may be obtained from the Corporate Secretary of EGEM at the above-mentioned address and telephone number.

This prospectus incorporates by reference financial statements audited by Arthur Andersen LLP for which we did not obtain the consent of Arthur Andersen LLP to the use of its audit report. Arthur Andersen LLP's consent was not obtained because, on June 3, 2002, Arthur Andersen LLP ceased to practice public accounting in Canada. Because Arthur Andersen LLP has not provided this consent, purchasers of trust units pursuant to this prospectus will not have the statutory right of action for damages against Arthur Andersen LLP prescribed by applicable securities legislation. Arthur Andersen LLP may not have sufficient assets available to satisfy judgments against it. Please read "Risk Factors Risks Relating to Arthur Andersen LLP."

The following documents have been incorporated by reference in this prospectus and form an integral part of this prospectus:

- the renewal annual information form of the Fund for the year ended December 31, 2001 dated April 10, 2002;

- the information circular and proxy statement of the Fund dated March 7, 2002 relating to the annual general and special meeting of unitholders of the Fund held on April 25, 2002, excluding those portions thereof which appear under the headings "Performance Chart" and "Statement of Corporate Governance Practices";

- the audited comparative consolidated financial statements of the Fund for the fiscal years ended December 31, 2001, 2000 and 1999, together with (i) the report of Deloitte & Touche LLP dated October 16, 2002 on the financial statements for the fiscal year ended December 31, 2001, and (ii) the report of PricewaterhouseCoopers LLP, the former auditors of EnerMark Income Fund, dated March 14, 2001 on the financial statements for the fiscal years ended December 31, 2000 and 1999;

management's discussion and analysis of financial condition and operating results of the Fund for the year ended December 31, 2001;

the unaudited comparative consolidated interim financial statements of the Fund as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001;

management's discussion and analysis of the Fund for the three and nine months ended September 30, 2002;

the audited consolidated financial statements of Enerplus Resources Fund (prior to the merger with EnerMark Income Fund on June 21, 2001, which was accounted for as a reverse take-over of Enerplus Resources Fund by EnerMark Income Fund) for the fiscal years ended December 31, 2000, 1999 and 1998, together with the report of Arthur Andersen LLP dated February 28, 2001 on those financial statements; and

the unaudited comparative consolidated financial statements of Enerplus Resources Fund (prior to the merger with EnerMark Income Fund) for the three months ended March 31, 2001 and 2000.

Any document of the type referred to in the preceding paragraph, including any material change reports (except confidential reports), comparative interim financial statements, comparative annual financial statements together with the accompanying auditors' report and any information circulars, which we file with a securities commission or other similar authority in Canada after the date of this prospectus and prior to the termination of this distribution will be deemed to be incorporated by reference into this prospectus.

We also incorporate by reference all future annual reports and any other information we file with the SEC pursuant to Section 13(a), 13(c) or 15(d) of the Exchange Act during such period.

Any statement contained in this prospectus or in a document incorporated or deemed to be incorporated by reference in this prospectus shall be deemed to be modified or superseded, for purposes of this prospectus, to the extent that a statement contained herein or in any other subsequently filed document that also is, or is deemed to be, incorporated by reference in this prospectus, modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it is made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this prospectus.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC, 450 Fifth Street, N.W. Washington, D.C. 20549, a registration statement on Form F-10 under the Securities Act of 1933, as amended, regarding the trust units offered by this prospectus. This prospectus, which forms part of the registration statement, does not contain all the information included in the registration statement. Some information is omitted and you should refer to the registration statement and its exhibits.

You may review a copy of the registration statement, including exhibits and documents filed with it, as well as any reports, statements or other information we file in the future with the SEC at the SEC's public reference facility at Room 1024, Judiciary Plaza, 450 Fifth Street, N.W., Washington, D.C. 20549. You may also obtain copies of these materials from the Public Reference Section of the SEC, Room 1024, Judiciary Plaza, 450 Fifth Street, N.W. Washington, D.C. 20549, at prescribed rates. You may call the SEC at 1-800-SEC-0330 for further information. These filings are also electronically available from the SEC's Electronic Document Gathering and Retrieval System (http://www.sec.gov), which is commonly known by the acronym EDGAR, as well as from commercial document retrieval services.

We are required to file reports under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and other information with the SEC. Under a multijurisdictional disclosure system adopted by the United States, such reports and other information may be prepared in accordance with the disclosure requirements of Canada, which requirements are different from those of the United States. In addition, we are subject to the filing requirements prescribed by the securities legislation of all Canadian provinces or territories. You are invited to read and copy any reports, statements or other information that we file with the Canadian provincial securities commissions or other similar regulatory authorities at their respective public reference rooms. These filings are also electronically available from the Canadian System for Electronic Document Analysis and Retrieval (http://www.sedar.com), which is commonly known by the acronym "SEDAR." The Canadian System for Electronic Document Analysis and Retrieval is the Canadian equivalent of the SEC's EDGAR. Reports and other information about us should also be available for inspection at the offices of the Toronto Stock Exchange and the New York Stock Exchange.

As a "foreign private issuer" under the Exchange Act, we intend to provide to our unitholders proxy statements and annual reports prepared in accordance with applicable Canadian law. Our annual reports will be available within 140 days of the end of each fiscal year and will contain our audited consolidated financial statements. We will also make available quarterly reports containing unaudited summary consolidated financial information for each of the first three fiscal quarters. We intend to prepare these financial statements in accordance with Canadian GAAP and to include a reconciliation to U.S. GAAP in the notes to the annual consolidated financial statements. We are exempt from provisions of the Exchange Act which require us to provide proxy statements in prescribed form to unitholders and which relate to short swing profit reporting and liability.

DOCUMENTS FILED AS PART OF THE U.S. REGISTRATION STATEMENT

A registration statement on Form F-10 has been filed with the SEC under the U.S. Securities Act of 1933, as amended, relating to this offering. The following documents have been filed with the SEC as part of the Registration Statement of which this prospectus is a part, insofar as called for by the SEC's Form F-10:

- the documents listed in this prospectus as incorporated by reference herein;
- the form of underwriting agreement;
- the comfort letter of Deloitte & Touche LLP with respect to the unaudited financial statements as at September 30, 2002 and for the three and nine months ended September 30, 2002 and 2001;
- the consent of Blake, Cassels & Graydon LLP;
- the consent of Burnet, Duckworth & Palmer LLP;
- the consent of Andrews & Kurth L.L.P.;
- the consent of Deloitte & Touche LLP;
- the consent of PricewaterhouseCoopers LLP;
- the consent of Sproule Associates Limited, independent petroleum consultants, with respect to the use of their report on our reserves and their report on a portion of Celsius' reserves;
- the consent of Gilbert Laustsen Jung Associates Ltd., independent petroleum consultants, with respect to the use of their report on a portion of Celsius' reserves;

the powers of attorney pursuant to which amendments to the Registration Statement may be signed; and

our trust indenture.

You can obtain copies of the documents incorporated herein by reference without charge from the Secretary of EGEM, at The Dome Tower, Suite 3000, 333 - 7th Avenue S.W., Calgary, Alberta, T2P 2Z1, telephone (403) 298-2200.

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GLOSSARY OF TERMS

In this prospectus, the following terms have the meanings specified below:

Enerplus and Our Organization

Celsius. Celsius Energy Resources Ltd., a corporation acquired by EnerMark on October 21, 2002 and subsequently amalgamated with and continued as "EnerMark Inc."

EGEM. Enerplus Global Energy Management Company.

EnerMark. EnerMark Inc. and its subsidiaries.

Enerplus, we, us and ***our.*** Enerplus Resources Fund, EnerMark Inc., Enerplus Resources Corporation and their subsidiaries, on a consolidated basis.

Enerplus Group. Enerplus, EGEM and their collective predecessors.

ERC. Enerplus Resources Corporation and its subsidiaries.

Fund. Enerplus Resources Fund only.

Operating Companies. EnerMark and ERC.

unitholders. Holders of trust units issued by the Fund.

Our Reserves

established reserves. Proved reserves plus 50% of probable reserves, before the deduction of royalties and based on escalated price and cost assumptions, unless otherwise indicated.

net proved reserves. The working interest share of proved reserves after the deduction of royalties, based on constant price and cost assumptions.

probable reserves. Those reserves which may be recoverable as a result of the beneficial effects which may be derived from the future institution of some form of pressure maintenance or other secondary recovery method, or as a result of a more favourable performance of the existing recovery mechanism than that which would be deemed proved at the present time, or those reserves which may reasonably be assumed to exist because of geophysical or geological indications and drilling done in regions which contain proved reserves. Probable reserves are presented before deduction of royalties and are based on escalated price and cost assumptions, unless otherwise indicated.

proved reserves. Those quantities of oil, natural gas and natural gas by-products which, upon analysis of geological and engineering data, appear with a high degree of certainty to be recoverable at commercial rates in the future from known oil and natural gas reservoirs under current economic and operating conditions for reserves based on constant price and cost assumptions, and presently anticipated economic and operating conditions for the reserves based on escalated price and cost assumptions.

proved developed reserves. Those proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

proved developed producing reserves. Those proved reserves which are presently being produced from completion intervals open for production in existing wells.

proved developed non-producing reserves. Those proved reserves which are currently not being produced but do exist in completed intervals but not producing in existing wells, behind casing in existing wells or at minor depths below the present bottom of existing wells. These proved reserves are expected to be produced through the existing wells in the predictable future. These reserves are classified as proved developed reserves since the cost of making such reserves available for production is relatively small compared to the cost of a new well.

proved undeveloped reserves. Those proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where relatively major expenditures are required for the completion of these wells or for the installation of processing and gathering facilities prior to the production of these reserves. Reserves on undrilled acreage are limited to those drilling units offsetting productive wells that are reasonably certain of production when drilled.

reserve life index. The number of years calculated by dividing the established reserves at a particular date (and in the case of Enerplus, at January 1 of a particular year) by our estimated gross production for the following twelve month period. Reserve life index is a metric commonly used in analyses of Canadian oil and gas entities. Established reserve life index and proved reserve life index use established reserves and proved reserves, respectively.

R/P ratio. The number determined by dividing net proved reserves by the trailing twelve month average net production of the property. R/P ratio is a metric commonly used in analyses of U.S. oil and gas entities.

Our Operations

AECO. The Western Canadian Sedimentary Basin natural gas pricing benchmark similar to NYMEX Henry Hub in the United States.

ARTC. Alberta Royalty Tax Credit.

Bbl, Bbls, MBbls and ***MMBbls.*** Barrel, barrels, thousands of barrels and millions of barrels, respectively.

Bbls/day. Barrels per day.

Boe, MBoe and ***MMBoe.*** Barrels of oil equivalent, thousands of barrels of oil equivalent and millions of barrels of oil equivalent, respectively, on the basis of one Boe being equal to one Bbl of oil or NGLs or 6 Mcf of natural gas.

Boe/day. Barrels of oil equivalent per day.

Crown. The applicable Canadian governmental body, generally referred to in the context of payment of royalties.

gross. When used to describe our share of production or reserves means the total of our working interests before deducting royalties payable to third parties and, with respect to land and wells, refers to the total number of acres or wells, as the case may be, in which we have an interest.

Mcf, MMcf and ***Bcf.*** One thousand cubic feet, one million cubic feet and one billion cubic feet of natural gas, respectively.

Mcf/day and ***MMcf/day.*** Thousand cubic feet per day and million cubic feet per day, respectively.

MMBTU. Millions of British thermal units.

net. When used to describe our share of production or reserves means the total of our working interests after deducting royalties payable to third parties and, with respect to land and wells, means our interest therein.

NGLs. Natural gas liquids.

NYMEX. New York Mercantile Exchange.

Working interest or ***WI.*** The percentage of undivided interest held by a party in an oil and gas property.

INDEX TO FINANCIAL STATEMENTS

ENERPLUS RESOURCES FUND

CONSOLIDATED BALANCE SHEET

($ thousands)
(Unaudited)

	September 30, 2002	December 31, 2001
ASSETS		
Current assets		
Cash and cash equivalents	$ 3,471	$ 979
Accounts receivable	75,638	100,089
Other current	3,377	4,869
	82,486	105,937
Property, plant and equipment	2,814,368	2,667,504
Accumulated depletion and depreciation	(643,572)	(489,188)
	2,170,796	2,178,316

	September 30, 2002	December 31, 2001
Deferred charges (Note 4)	1,847	
	$ 2,255,129	$ 2,284,253
LIABILITIES		
Current liabilities		
Accounts payable	$ 76,582	$ 72,341
Distributions payable to unitholders	22,426	20,860
Payable to related party (Note 3)	10,392	7,915
	109,400	101,116
Long-term debt (Note 4)	362,458	412,589
Future income taxes	314,222	333,560
Accumulated site restoration	58,538	55,403
Deferred credits	4,848	6,591
Payable to related party (Note 3)	1,525	1,909
	741,591	810,052
EQUITY		
Unitholders' capital (Note 2)	1,958,521	1,826,507
Accumulated income	389,069	324,570
Accumulated cash distributions	(943,452)	(777,992)
	1,404,138	1,373,085
	$ 2,255,129	$ 2,284,253
Number of Units outstanding (thousands)	74,751	69,532

ENERPLUS RESOURCES FUND

CONSOLIDATED STATEMENT OF INCOME

($ thousands except per Unit amounts)
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
	2002	2001	2002	2001
REVENUES				
Oil and gas sales	$ 151,286	$ 163,824	$ 428,408	$ 492,420
Crown royalties	(21,161)	(24,231)	(66,013)	(89,536)

	Three Months Ended September 30		Nine Months Ended September 30	
Freehold and other royalties	(7,823)	(8,713)	(22,502)	(26,032)
	122,302	130,880	339,893	376,852
Interest and other income	31	110	338	680
	122,333	130,990	340,231	377,532
EXPENSES				
Operating	34,689	34,717	95,853	81,157
General and administrative	3,352	1,633	10,085	6,367
Management fees (Note 3)	7,216	2,497	13,571	6,957
Interest (Note 5)	5,169	5,121	12,705	13,473
Depletion, depreciation and amortization	52,656	55,423	158,906	135,885
	103,082	99,391	291,120	243,839
Income before taxes	19,251	31,599	49,111	133,693
Capital taxes	1,294	1,352	3,950	3,624
Future income tax	(11,124)	5,106	(19,338)	(13,260)
NET INCOME	$ 29,081	$ 25,141	$ 64,499	$ 143,329
Net income per trust unit				
Basic	$ 0.41	$ 0.39	$ 0.92	$ 2.82
Diluted	$ 0.41	$ 0.39	$ 0.92	$ 2.82
Weighted average number of Units outstanding (thousands)				
Basic	70,850	64,776	70,066	50,738
Diluted	71,019	64,853	70,181	50,817

CONSOLIDATED STATEMENT OF ACCUMULATED INCOME

($ thousands)
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
	2002	**2001**	**2002**	**2001**
Accumulated income, beginning of period	$ 359,988	$ 262,489	$ 324,570	$ 144,301
Net income	29,081	25,141	64,499	143,329
Accumulated income, end of period	$ 389,069	$ 287,630	$ 389,069	$ 287,630

ENERPLUS RESOURCES FUND

CONSOLIDATED STATEMENT OF CASH FLOWS

($ thousands except per Unit amounts)
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
	2002	**2001**	**2002**	**2001**
OPERATING ACTIVITIES				
Net income	$ 29,081	$ 25,141	$ 64,499	$ 143,329
Depletion, depreciation and amortization	52,656	55,423	158,906	135,885
Future income tax	(11,124)	5,106	(19,338)	(13,260)
Site restoration and abandonment costs incurred	(1,023)	(719)	(3,130)	(1,343)
Funds flow from operations	69,590	84,951	200,937	264,611
Decrease (increase) in non-cash operating working capital	1,787	(7,565)	21,832	(35,779)
	71,377	77,386	222,769	228,832
FINANCING ACTIVITIES				
Issue of trust units, net of issue costs	124,591	11,253	131,274	45,845
Cash distributions to unitholders	(61,323)	(92,677)	(163,894)	(252,512)
Increase (decrease) in long-term debt	(78,351)	79,768	(50,131)	93,325
Payment to related party (Note 3)	(128)	(127)	(384)	(127)
Deferred charges			(1,892)	
	(15,211)	(1,783)	(85,027)	(113,469)
INVESTING ACTIVITIES				
Property, plant and equipment	(54,366)	(101,495)	(137,696)	(156,323)
Proceeds on sale of property, plant and equipment	308	34,755	2,446	61,581
Corporate acquisitions		(8,792)		(20,594)
	(54,058)	(75,532)	(135,250)	(115,336)
Increase in cash	2,108	71	2,492	27
Cash, beginning of period	1,363	802	979	846
Cash, end of period	$ 3,471	$ 873	$ 3,471	$ 873
Funds flow from operations per unit	$ 0.98	$ 1.31	$ 2.87	$ 5.22
SUPPLEMENTARY CASH FLOW INFORMATION				
Cash income taxes paid	$	$	$	$
Cash interest paid	$ 2,099	$ 5,373	$ 9,483	$ 13,278

CONSOLIDATED STATEMENT OF ACCUMULATED CASH DISTRIBUTIONS

($ thousands)
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
	2002	2001	2002	2001
Accumulated cash distributions, beginning of period	$ 881,863	$ 619,051	$ 777,992	$ 447,158
Cash distributions	61,589	87,712	165,460	259,605
Accumulated cash distributions, end of period	$ 943,452	$ 706,763	$ 943,452	$ 706,763

ENERPLUS RESOURCES FUND

SELECTED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(Tabular amounts in thousands of Canadian dollars and thousands of Units except per Unit amounts)
(Unaudited)

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 consolidated 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 take-over 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 nine months ended September 30, 2002 but the comparative figures for the prior year include the accounts of EnerMark as at and for the nine months ended September 30, 2001, plus the results of Enerplus from June 21, 2001 to September 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 consolidated 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)	**September 30, 2002 Units**		**September 30, 2002 Amount**	**December 31, 2001 Units**		**December 31, 2001 Amount**
Balance, beginning of period	69,532	$	1,826,507	40,925	$	1,050,986
Issued for cash:						
Pursuant to public offerings	4,750		120,886	4,313		101,039
Pursuant to option plans	98		1,905	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 and Unit Purchase Plan	340		8,483	659		16,577
Issued for acquisition of property interests	31		740	1,267		31,846
Balance, end of period	74,751	$	1,958,521	69,532	$	1,826,507

On September 12, 2002, Enerplus closed an equity offering of 4,750,000 trust units at a price of $26.85 per trust unit for gross proceeds of $127,538,000 (net $120,886,000).

(b)

Trust Unit Option Plan

As at September 30, 2002, 150,000 options issued pursuant to the Trust Unit Option Plan were outstanding, representing 0.2% of the total units outstanding. Activity for the options issued pursuant to the option plan is summarized as follows:

(thousands except per Unit amounts)	**September 30, 2002 Number of Options**		**September 30, 2002 Weighted Average Exercise Price**	**December 31, 2001 Number of Options**		**December 31, 2001 Weighted Average Exercise Price**
Options outstanding at beginning of period	264	$	20.93	363[(1)]	$	21.03
Exercised	(98)	$	19.55	(55)	$	21.94
Cancelled	(16)	$	22.73	(44)	$	20.47
Options outstanding at end of period	150	$	21.75	264	$	20.93
Options exercisable at end of period	119			99		

(1) Number of options represent the balance at June 21, 2001 after the Merger of Enermark and Enerplus.

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 September 30, 2002, a total of 1,348,000 rights were issued (2,740,000 reserved) pursuant to the Trust Unit Rights Incentive Plan of which none are exercisable. 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. Based on second and third quarter 2002 results, the exercise price has been calculated to be reduced by $0.07 per trust unit (effective October 2002) and $0.14 per trust unit (effective January 2003) respectively.

As it is not possible to determine the fair value of rights granted under the plan, compensation costs 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 nine months ended September 30, 2002, net income would be reduced by $150,000 and $183,000, for the estimated compensation cost associated with rights granted under the plan on or after January 1, 2002 with a 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)	September 30, 2002 Number of Rights	September 30, 2002 Weighted Average Exercise Price	December 31, 2001 Number of Rights	December 31, 2001 Weighted Average Exercise Price
Rights outstanding at beginning of period	1,318	$ 24.50		
Granted	145	$ 26.66	1,360	$ 24.50
Cancelled	(115)	$ 24.47	(42)	$ 24.50
Rights outstanding at end of period	1,348	$ 24.63	1,318	$ 24.50

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 $13,571,000 are reported on the consolidated statement of income for the nine months ended September 30, 2002. This included earned base management fees of $6,291,000 and accrued performance fees of $7,280,000. The performance fees are not determined until December 31, 2002, and as such, this amount may increase or decrease throughout the remainder of the year. As at September 30, 2002, $9,883,000 was payable to EGEM, pursuant to this agreement.

In addition, pursuant to a share purchase agreement related to the Merger, the Fund acquired shares of Enerplus Resources Corporation from EGEM for $2,545,000 payable over five years in quarterly installments of $127,000 through a reduction of management fees. At September 30, 2002, the indebtedness remaining pursuant to this agreement was $2,035,000 of which $509,000 has been classified as current.

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

4. LONG-TERM DEBT

	September 30, 2002	December 31, 2001
Bank credit facilities	$ 94,130	$ 412,589

		September 30, 2002		December 31, 2001
Senior unsecured notes		268,328		
Total long-term debt	$	362,458	$	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 $1,892,000, are being amortized over the term of the Notes. As at September 30, 2002, the amount not amortized associated with these costs was $1,847,000.

Subsequent to September 30, 2002 the Fund's borrowing base was increased to $700,000,000. The increase resulted in the amount of credit available under the bank credit facilities (the "Facilities") being increased to $431,672,000 from $351,672,000. The Facilities remain unsecured and consist of a $402,000,000 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 the instruments outstanding as at September 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 value of the $75.0 million interest rate swaps as at September 30, 2002, represent an unrealized loss of $2.0 million. The mark-to-market value of the cross currency interest rate swap related to the Senior Unsecured Notes as at September 30, 2002 represented an unrealized gain of $40.0 million.

Crude oil:

Enerplus has entered into the following financial option contracts on its gross crude oil production that are designed to reduce a downward impact of crude oil prices. The remaining costs to be amortized associated with these transactions are approximately $215,000. The mark-to-market value of the financial crude oil contracts as at September 30, 2002 reflects an unrealized loss of $8,979,000.

		WTI Crude Oil Price US$					
Term	**Volume 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
Oct. 1, 2002 Sept. 30, 2004							
3-way(2)	1,500	US$	29.00	US$	22.00	US$	19.25
Jan.1, 2003 Sept. 30, 2004							
3-way(2)	1,500	US$	30.00	US$	23.00	US$	20.00
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 June 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
Jan. 1, 2003 December 31, 2004							
3-way(3)	1,500	US$	29.50	US$	22.00	US$	20.00

(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 $69,000 and is being amortized over the remaining term.

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

(3) Transactions entered into subsequent to September 30, 2002 that are not included in the mark-to-market values.

Natural Gas:

In addition to the crude oil price protection initiatives described previously, Enerplus also has physical and financial contracts in place on its gross natural gas production as described below. The remaining costs to be amortized associated with these contracts are $0.01 per trust unit or $509,000 in 2002 and $0.02 per

trust unit or $1,694,000 in 2003. The mark-to-market value of the financial natural gas contracts as at September 30, 2002 reflects an unrealized loss of $17,981,000.

	MMcf/day	AECO Cdn$/Mcf				
Term	**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			
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				
Nov. 1, 2002 Mar. 31, 2003						
3-way(2)(3)	4.8	$ 7.39	$ 5.28	$ 4.22		
3-way(4)(5)	4.8	$ 7.39	$ 5.28	$ 4.22		
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	9.5	$ 7.91	$ 4.27	$ 3.17		
Jan. 1, 2003 June 30, 2004						
3-way	9.5	$ 7.39	$ 4.75	$ 3.17		
Jan. 1, 2003 Sept. 30, 2004						
3-way(2)	9.5	$ 6.67	$ 4.75	$ 3.17		
3-way(2)	9.5	$ 7.39	$ 4.75	$ 3.69		
Jan. 1, 2003 Oct. 31, 2006						
Swap(5)	9.5		$ 5.47			
Apr.1, 2003 Oct. 31, 2003						
Collar(2)	4.8	$ 6.25	$ 4.75			
Collar(5)	4.8	$ 6.25	$ 4.75			

Jan. 1, 2004 Oct. 31, 2004						
Swap	3.8		$ 2.90			
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 remaining option premiums for these instruments are $2,203,000 and are being amortized over their remaining terms.

(2) Additional transactions entered into during the third quarter of 2002.

(3) Enerplus sells physical gas at the Month Index less $0.05/Mcf.

(4) Enerplus sells physical gas at the Month Index less $0.11/Mcf.

(5) Transactions entered into subsequent to September 30, 2002 that are not included in the mark-to-market values.

6. COMMITMENTS AND CONTINGENCIES

The acquisition of the working interest in Oil Sands Lease #24 (Joslyn Creek Lease) included the assumption of approximately $4,100,000 in contingent project debt that was comprised of $3,360,000 of principal and approximately $740,000 in accrued interest. Interest is accrued at the Bank of Canada prime business rate and is not compounded. The debt is contingent on both production and pricing hurdles with respect to development on the lease. As it is too early in the development of this project to determine if these hurdles will be satisfied, the contingent debt has not been accrued in the consolidated financial statements.

7. EVENT SUBSEQUENT TO SEPTEMBER 30, 2002

Subsequent to September 30, 2002, the Fund acquired all of the issued and outstanding shares of Celsius Energy Resources Ltd., a private oil and gas company, for total cash consideration of approximately $165.9 million including working capital adjustments. The acquisition will be accounted for by the purchase method with the results of operations included in the consolidated financial statements of the Fund from the closing date of October 21, 2002.

8. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Fund's consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These principles, as they pertain to the Fund's

consolidated statements, differ from United States generally accepted accounting principles ("U.S. GAAP") as follows:

(a) Under U.S. GAAP, for Securities and Exchange Commission registrants following full cost accounting, the carrying value of petroleum and natural gas properties and related facilities, net of deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at ten percent (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproven properties. Under Canadian GAAP, the Ceiling Test is calculated without application of a discount factor, but includes general and administration, management fees and interest expense.

Where the amount of a Ceiling Test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion, depreciation and amortization will differ in subsequent years. As at September 30, 2002, the application of the Ceiling Test under U.S. GAAP did not result in a write-down of capitalized costs. At September 30, 2001, the application of the Ceiling Test under U.S. GAAP resulted in a write-down of $744.3 million ($458.4 million after tax) of capitalized costs.

(b) SFAS 123 "Accounting for Stock Based Compensation", establishes financial accounting and reporting standards for stock-based compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by SFAS 123, Enerplus has elected to continue to measure compensation expense based on the intrinsic value of the award when accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board Opinion 25 ("APB 25"). Since all Unit Option and Trust Unit Rights were granted with an exercise price equal to the market price at the date of the grant, no compensation cost has been charged to income. Had compensation cost for all of Enerplus' stock options been determined based on the fair market value at the grant dates of the awards consistent with methodology prescribed by SFAS 123, Enerplus' net income (loss) and net income (loss) per unit for three and nine month periods ended, September 30, 2002 and 2001 would have been the pro forma amounts indicated below:

	Three months ended September 30, 2002	Three months ended September 30, 2001	Nine months ended September 30, 2002	Nine months ended September 30, 2001
	($ thousands except per Unit amounts)			
Net income (loss):				
As reported under U.S. GAAP	$ 29,899	$ (431,037)	$ 83,211	$ (282,686)
Pro forma	$ 29,612	$ (431,253)	$ 82,619	$ (282,915)
Net income (loss) per unit				
Basic				
As reported under U.S. GAAP	$ 0.42	$ (6.65)	$ 1.19	$ (5.57)
Pro forma	$ 0.42	$ (6.65)	$ 1.18	$ (5.57)
Diluted				
As reported under U.S. GAAP	$ 0.42	$ (6.65)	$ 1.19	$ (5.57)
Pro forma	$ 0.42	$ (6.65)	$ 1.18	$ (5.57)

As the exercise price of the trust unit rights is subject to downward revisions from time to time, the trust unit rights plan is a variable compensation plan under U.S. GAAP. Accordingly, compensation expense is determined on the rights as the excess of the market price over the exercise price of the rights at the end of each reporting period and is deferred and recognized in income over the vesting period of the rights. During the first quarter of 2002, a $0.12 per right downward reduction in the exercise price on 1.4 million rights had occurred resulting in the Trust Unit Rights plan being considered as a variable compensation plan. Accordingly, a charge to net income was recognized for the three and nine months ending September 30, 2002 of $3.5 million and $5.6 million respectively. For the three and nine months ended September 30, 2001, no downward revision in exercise price had occurred and no compensation expense has been recognized for the rights.

(c)

Under U.S. GAAP the measurement date for acquisitions is the date an acquisition is announced. Previously under Canadian GAAP the measurement date for the acquisition was the closing date. Therefore, under U.S. GAAP, unitholders' capital and property, plant and equipment have been increased by $37.3 million as of September 30, 2001 for differences in the value of trust units issued to effect the Merger.

(d)

Effective January 1, 2001, for U.S. reporting purposes, the Fund adopted Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities". SFAS 133 establishes accounting and reporting standards requiring that all derivative instruments (including derivative instruments embedded in other contracts), as defined, be recorded in the balance sheet as either an asset or a liability measured at fair value and requires that changes in fair value be recognized currently in income unless specific hedge accounting criteria are met.

With respect to its crude oil and natural gas contracts that do not qualify for hedge accounting treatment under SFAS 133, the Fund has recognized in earnings a loss of $14.7 million ($8.4 million net of tax) and $26.2 million ($15.0 million net of tax) for the three and nine months ended September 30, 2002, respectively.

(e)

U.S. GAAP requires the reporting of comprehensive income in addition to net earnings. The Fund's nine month comprehensive income includes a net unrealized gain on instruments qualifying for hedge accounting under SFAS 133 comprised of a $2.0 million ($1.2 million net of tax) unrealized hedging loss on the $75 million interest rate swap, an unrealized hedging gain of $40.0 million ($23.0 million net of tax) relating to the combined cross currency and interest rate swap on the senior unsecured notes and an unrealized loss of $0.8 million relating to the change in fair value of the Fund's natural gas contracts for the period. For the three months ended September 30, 2002 the Fund's comprehensive income includes an unrealized hedging loss of $1.7 million ($1.0 million net of tax) on the $75 million interest rate swap, an unrealized hedging gain of $39.9 million ($22.9 million net of tax) on the combined cross currency and interest rate swap and an unrealized loss of $0.3 million relating to the change in fair value of the Fund's natural gas contracts for the period. As at September 30, 2001, the Fund's three and nine month net income was equal to its comprehensive income.

(f)

Recent Developments in U.S. Accounting Standards

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS 143, "Accounting for Asset Retirement Obligations." SFAS 143 requires liability recognition for retirement obligations associated with tangible long-lived assets. The obligations included within the scope of

SFAS 143 are those for which the Fund faces a legal obligation for settlement. The initial measurement of the asset retirement obligation is to be at fair value. The asset retirement cost equal to the fair value of the retirement obligation is to be capitalized as part of the cost of the related long-lived asset and amortized to expense over the useful life of the asset. SFAS 143 is effective for all fiscal years beginning after June 15, 2002. The total impact on the Fund's financial statements has not yet been determined.

The application of U.S. GAAP would have the following effects on net income as reported:

	Three months ended September 30, 2002	Three months ended September 30, 2001	Nine months ended September 30, 2002	Nine months ended September 30, 2001
	($ thousands except per Unit amounts)			
Net income as reported in the Consolidated Statement of Income Canadian GAAP	$ 29,081	$ 25,141	$ 64,499	$ 143,329
Adjustments, net of applicable income tax				
Write-down of property, plant and equipment		(458,474)		(458,474)
Depletion, depreciation and amortization	12,769	3,629	39,289	14,177
Compensation expense	(3,529)		(5,567)	
Unrealized gain (loss) on financial derivatives	(8,422)	(1,333)	(15,010)	18,282
Net income (loss) U.S. GAAP	29,899	(431,037)	83,211	(282,686)
Net unrealized gain on hedging instruments	21,733		21,347	
Comprehensive income (loss)	$ 51,632	$ (431,037)	$ 104,558	$ (282,686)
Net income (loss) per unit				
Basic	$ 0.42	$ (6.65)	$ 1.19	$ (5.57)
Diluted	$ 0.42	$ (6.65)	$ 1.19	$ (5.57)
Weighted average number of units outstanding				
Basic	70,850	64,776	70,066	50,738
Diluted	71,019	64,853	70,181	50,817
Accumulated other comprehensive income				
Balance, beginning of period	$ (386)	$	$	$
Net unrealized gain on hedging instruments	21,733		21,347	
Balance, end of period	$ 21,347	$	$ 21,347	$

The application of U.S. GAAP would have the following effects on the balance sheet as reported:

	Canadian GAAP	Increase (decrease)	U.S.GAAP
		($ thousands)	
September 30, 2002			
Financial derivative assets	$	$ 40,000	$ 40,000
Property, plant and equipment, net	2,170,796	(954,829)	1,215,967
Financial derivative liabilities		29,397	29,397
Future income taxes	314,222	(377,361)	(63,139)
Unitholders' capital	1,958,521	29,626	1,988,147
Contributed surplus		5,567	5,567
Accumulated income	389,069	(623,405)	(234,336)
Accumulated other comprehensive income		21,347	21,347
December 31, 2001			
Financial derivative assets		274	274
Property, plant and equipment, net	2,178,316	(1,018,610)	1,159,706
Financial derivative liabilities		711	711
Future income taxes	333,560	(406,556)	(72,996)
Unitholders' capital	1,826,507	29,626	1,856,133
Accumulated income	324,570	(642,117)	(317,547)

AUDITORS' REPORT

To the Unitholders of Enerplus Resources Fund:

We have audited the consolidated balance sheet of Enerplus Resources Fund as at December 31, 2001 and the consolidated statements of income, accumulated income, accumulated cash distributions, and cash flows for the year then ended. These financial statements are the responsibility of the Fund's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2001 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements as at December 31, 2000 and 1999 and for the years then ended are the financial statements of EnerMark Income Fund (See Note 1 to the financial statements). These financial statements were audited by other auditors who expressed an opinion without reservation on those consolidated financial statements in their report dated March 14, 2001. The opinion of such auditors, however, did not cover the reconciliation of differences between Canadian and United States generally accepted accounting principles as disclosed in Note 10. We have audited the reconciliations pertaining to 2000 and 1999. In our opinion, the reconciliations are appropriate and have been presented on a basis consistent with the current year.

Calgary, Canada
October 16, 2002

(Signed) DELOITTE & TOUCHE LLP
Chartered Accountants

AUDITORS' REPORT

To the Unitholders of Enerplus Resources Fund:

We have audited the consolidated balance sheet of Enerplus Resources Fund as at December 31, 2000 and 1999 and the consolidated statements of net income, accumulated income, accumulated distributions and cash flows for each of the years in the two year period ended December 31, 2000, including notes 2 through 9. These financial statements are the responsibility of the Fund's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by Management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2000 and 1999 and the results of its operations and cash flows for each of the years then ended in accordance with Canadian generally accepted accounting principles.

Our opinion does not cover the acquisition of Enerplus Resources Fund as disclosed in Note 1, reconciliation of differences between Canadian and United States generally accepted accounting principles as disclosed in Note 10 or the description of subsequent events as disclosed in Note 11.

Calgary, Alberta — (Signed) PRICEWATERHOUSECOOPERS LLP
March 14, 2001 — Chartered Accountants

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ENERPLUS RESOURCES FUND

CONSOLIDATED BALANCE SHEET

As at December 31

($ thousands)

	2001	2000	1999
		(Note 1)	(Note 1)
ASSETS			
Current assets			
Cash and cash equivalents	$ 979	$ 846	$ 2,482
Accounts receivable	100,089	77,086	15,506
Other	4,869	6,474	1,365
	105,937	84,406	19,353
Property, plant and equipment	2,667,504	1,791,649	789,174
Accumulated depletion and depreciation	(489,188)	(308,356)	(232,889)
	2,178,316	1,483,293	556,285
Deferred reorganization charges, net of amortization (Note 2)		253	1,263
	$ 2,284,253	$ 1,567,952	$ 576,901

LIABILITIES AND EQUITY

	2001	2000	1999
Current liabilities			
Accounts payable	$ 72,341	$ 91,135	$ 19,705
Distributions payable to Unitholders (Note 9)	20,860	18,925	7,547
Payable to related company (Note 6)	7,915	14,222	2,852
	101,116	124,282	30,104
Bank debt (Note 3)	412,589	275,944	131,315
Future income taxes (Note 5)	333,560	353,115	33,593
Accumulated site restoration	55,403	37,596	14,035
Deferred credits (Note 2)	6,591		
Payable to related party (Note 6)	1,909		
Non-controlling interest (Note 7)		25,013	
	810,052	691,668	178,943
EQUITY			
Unitholders' capital (Note 4)	1,826,507	1,054,859	592,693
Accumulated income	324,570	144,301	78,328
Accumulated cash distributions (Note 9)	(777,992)	(447,158)	(303,167)
	1,373,085	752,002	367,854
	$ 2,284,253	$ 1,567,952	$ 576,901

Signed on behalf of the Board:

(Signed) DOUGLAS R. MARTIN
Director

(Signed) ROBERT L. NORMAND
Director

ENERPLUS RESOURCES FUND

CONSOLIDATED STATEMENT OF INCOME

For the year ended December 31

($ thousands except per Unit amounts)

	2001	2000 (Note 1)	1999 (Note 1)
REVENUES			
Oil and gas sales	$ 639,379	$ 343,182	$ 169,541
Crown royalties	(101,114)	(65,451)	(23,902)
Freehold and other royalties	(31,546)	(15,492)	(8,243)
	506,719	262,239	137,396
Interest and other income	858	611	1,045

	2001	2000	1999
	507,577	262,850	138,441
EXPENSES			
Operating	120,082	54,997	37,228
General and administrative	12,971	7,202	5,726
Management fee (Note 6)	9,323	4,556	2,204
Interest (Note 3)	17,605	15,322	9,078
Depletion, depreciation and amortization	194,080	80,309	61,857
	354,061	162,386	116,093
Income before taxes	153,516	100,464	22,348
Capital taxes	4,722	2,936	1,551
Future income tax provision (recovery) (Note 5)	(31,475)	15,378	(4,957)
	(26,753)	18,314	(3,406)
NET INCOME	$ 180,269	$ 82,150	$ 25,754
Net income per Trust Unit			
Basic	$ 3.28	$ 3.06	$ 1.25
Diluted	$ 3.28	$ 3.05	$ 1.25
Weighted average number of Trust Units outstanding (thousands)			
Basic	54,907	26,841	20,532
Diluted	54,956	26,928	20,607

CONSOLIDATED STATEMENT OF ACCUMULATED INCOME

For the year ended December 31

($ thousands)

	2001	2000 (Note 1)	1999 (Note 1)
Accumulated income, beginning of year	$ 144,301	$ 78,328	$ 52,574
Change in accounting policy (Note 2)		(16,177)	
Net income	180,269	82,150	25,754
Accumulated income, end of year	$ 324,570	$ 144,301	$ 78,328

ENERPLUS RESOURCES FUND

CONSOLIDATED STATEMENT OF CASH FLOWS

For the year ended December 31

($ thousands)

	2001	2000	1999
		(Note 1)	(Note 1)
OPERATING ACTIVITIES			
Net income	$ 180,269	$ 82,150	$ 25,754
Depletion, depreciation and amortization	194,080	80,309	61,857
Future income taxes (recovery) (Note 5)	(31,475)	15,378	(4,957)
Site restoration and abandonment costs incurred	(2,628)	(1,471)	(1,124)
Gain on sale of investment			(565)
Funds flow from operations	340,246	176,366	80,965
Decrease (increase) in non-cash operating working capital	(52,928)	(11,354)	32
	287,318	165,012	80,997
FINANCING ACTIVITIES			
Issue of Trust Units, net of issue costs (Note 4)	151,411	120,600	54,689
Cash distributions to Unitholders	(328,899)	(132,613)	(70,603)
Bank debt (payments) proceeds	58,021	77,765	(53,579)
	(119,467)	65,752	(69,493)
INVESTING ACITIVITIES			
Property, plant and equipment	(228,345)	(64,984)	(25,509)
Proceeds on sale of property, plant and equipment	75,276	18,481	16,957
Corporate acquisitions (Notes 1 and 7)	(14,649)	(186,897)	(2,925)
Proceeds on sale of investments		1,000	773
	(167,718)	(232,400)	(10,704)
Increase (decrease) in cash	133	(1,636)	800
Cash, beginning of year	846	2,482	1,682
Cash, end of year	$ 979	$ 846	$ 2,482
SUPPLEMENTARY CASH FLOW INFORMATION			
Cash income taxes paid	$	$	$
Cash interest paid	$ 17,162	$ 15,199	$ 9,001

CONSOLIDATED STATEMENT OF ACCUMULATED CASH DISTRIBUTIONS

For the year ended December 31

($ thousands)

	2001	2000	1999
		(Note 1)	(Note 1)
Accumulated cash distributions, beginning of year	$ 447,158	$ 303,167	$ 228,272
Cash distributions	330,834	143,991	74,895
Accumulated cash distributions, end of year (Note 9)	$ 777,992	$ 447,158	$ 303,167

ENERPLUS RESOURCES FUND

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2001, 2000 AND 1999

(Tabular amounts in thousands of Canadian dollars and thousands of Units except per Unit amounts)

1. ACQUISITION OF ENERPLUS RESOURCES FUND

The Merger of EnerMark Income Fund ("EnerMark") and Enerplus Resources Fund ("Enerplus" or the "Fund") which occurred on June 21, 2001 ("Merger") was accounted for as a reverse take-over as the Unitholders of EnerMark became the controlling Unitholders of the Fund after the Merger. Under this form of purchase accounting, EnerMark is deemed to have acquired Enerplus and the consolidated financial statements of the Fund for the year ended December 31, 2001 include only EnerMark's operating results prior to the Merger and the results of the merged Fund thereafter. All comparative figures and references to prior years are those of EnerMark. All disclosures of Trust Units, warrants and options and per Unit data up to June 21, 2001 Merger date have been restated using the Merger exchange ratio of 0.173 Enerplus Unit for each EnerMark Unit (the "Merger Exchange Ratio").

EnerMark is deemed to have acquired all of the outstanding Trust Units of Enerplus on June 21, 2001 for fair market value consideration totalling $600,745,000. The 20,863,000 Trust Units of Enerplus which were outstanding prior to the Merger were recorded as deemed consideration at a value of $582,817,000 representing an exchange value of $27.94 per Trust Unit. In addition, costs and other charges of $17,928,000 related to the acquisition were recorded.

The net assets acquired and liabilities assumed are as follows:

Property, plant and equipment	$ 704,838
Working capital deficiency	(10,415)
Long-term debt assumed	(78,624)
Site restoration and abandonment	(14,530)
Future income taxes	(524)
Net assets acquired	$ 600,745

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Management of Enerplus prepares the financial statements following Canadian generally accepted accounting principles. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a)

Organization and Basis of Accounting

The Fund is an open-end investment trust created under the laws of the Province of Alberta operating pursuant to the Amended and Restated Trust Indenture between EnerMark Inc., its wholly-owned subsidiary Enerplus Resources Corporation ("ERC") and CIBC Mellon Trust Company as Trustee. The beneficiaries of the Fund (the "Unitholders") are holders of Trust Units (the "Trust Units") issued by the Fund. The Fund is a limited-purpose trust whose purpose is to invest in securities of its wholly-owned subsidiary EnerMark Inc., invest in royalties granted by EnerMark Inc. and ERC, administer the assets and liabilities of the Fund and make distributions to the Unitholders.

The Fund's financial statements include the accounts of the Fund, EnerMark Inc. and its subsidiaries on a consolidated basis. All inter-entity transactions have been eliminated.

(b)

Property, Plant and Equipment

Oil and Natural Gas

The Fund follows the full cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against earnings, and renewals and enhancements which extend the recoverable reserves of the property, plant and equipment are capitalized. During 2001, general and administrative costs of $7,547,000 (2000 $7,925,000, 1999 $3,734,000) were capitalized.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would significantly alter the rate of depletion.

Other Equipment

All other equipment is carried at cost and is depreciated over the estimated useful lives of the assets at annual rates varying from 10% to 30%.

(c)

Ceiling Test

The Fund places a limit on the aggregate cost of property, plant and equipment, which may be carried forward for amortization against revenues of future periods (the "Ceiling Test"). The Ceiling Test is a cost recovery test whereby the capitalized costs less accumulated depletion and depreciation, accumulated site restoration and future income taxes are limited to an amount equal to estimated undiscounted future net revenues from proven reserves, plus the unimpaired costs of non-producing properties, less estimated future general and administrative expenses, site restoration cost, management fees, financing costs and capital taxes. Costs and prices at the balance sheet date are used in determining Ceiling Test amounts. Any costs carries on the balance sheet in excess of the Ceiling Test limitation are charged to earnings.

(d)

Depletion and Depreciation

The provision for depletion and depreciation of oil and natural gas assets is calculated using the unit-of-production method based on the Fund's share of estimated proven reserves before royalties. Reserves are converted to equivalent units on the basis of approximate relative energy content based on the Fund's share of estimated proven reserves before royalties.

(e)

Site Restoration and Abandonment

The provision for estimated site restoration costs is determined using the unit-of-production method and is included in depletion, depreciation and amortization expense. Actual site restoration costs are charged against the accumulated liability.

(f)

Joint Venture

Substantially all oil and natural gas production activities are conducted jointly with others. Accordingly, the accounts reflect the Fund's proportionate interest in these activities.

(g)

Income Taxes

The Fund is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed of distributable to the Unitholders. As the Fund distributes all of its taxable income to

the Unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Fund, no provision for income tax has been made in the Fund.

The Fund follows the liability method of accounting for income taxes. Under this methodology, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Fund's corporate subsidiaries and their respective tax bases, using substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

(h)

Deferred Reorganization Charges

Deferred reorganization charges were related to the inception of EnerMark and have been amortized over a five-year period ended March 31, 2001.

(i)

Deferred Credits

The deferred credits are costs associated with the mark-to-market valuation of Enerplus' natural gas price forward contracts which were "out-of-the-money" at the date of the Merger. This deferred credit will be amortized to income over the life of the natural gas financial contract ending October 31, 2004.

(j)

Financial Instruments

The Fund uses various financial instruments to manage risks associated with crude oil and natural gas price fluctuations and to manage interest rates. The instruments are not used for trading purposes and constitute effective hedges. Proceeds and costs realized from holding the crude oil and natural gas contracts are recognized in oil and gas revenues at the time each transaction under a contract is settled. The costs or proceeds realized from holding the interest rate swaps are recognized in interest expense at the time each transaction is settled.

(k)

Cash and Cash Equivalents

The Fund considers all highly liquid investments with a maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist primarily of funds on deposit under various terms. Cash and cash equivalents are stated at cost which approximates fair value.

(l)

Change in Accounting Policy

Effective January 1, 2000 the Fund, on a retroactive basis, adopted the liability method of accounting for income taxes in accordance with the new Canadian Institute of Chartered Accountants income tax standard. The cumulative effect as at January 1, 2000 was to increase future income taxes payable and decrease accumulated income by $16,177,000. The 1999 financial statements have not been restated for the change. The new recommendations do not affect the Fund's cash flow or liquidity.

3. BANK DEBT

As at December 31, 2001 Enerplus had banking arrangements for each of ERC and EnerMark Inc. under separate, syndicated, revolving, extendible production and operating facilities (the "Facilities") in an aggregate amount of $585,000,000 (2000 $420,000,000, 1999 $200,000,000). The Facilities were secured by fixed and floating charge debentures on substantially all of the assets held by EnerMark Inc. and ERC.

The terms of the banking arrangements provided Enerplus with various borrowing options including prime rate based advances and bankers acceptances. The average borrowing rate for the year ended December 31, 2001 was 2.98%. Interest on the bank loan amounted to $17,346,000 in 2001 (2000 $14,418,000, 1999 $9,031,000).

As at March 1, 2002, Enerplus renegotiated the Facilities into a single syndicated facility (the "Combined Facility") in the amount of $620,000,000 which will be reviewed on May 31, 2002 and annually on May 31 of each year, thereafter. The Combined Facility is unsecured and consists of a $590,000,000, 364 day revolving committed line, with an incremental two year term and a $30,000,000 demand operating line. As with the former Facilities, the Combined Facility allows various borrowing options including prime rate based advances and banker's acceptances.

In the event that the revolving bank line is not extended at the end of the 364 day revolving period, no payments are required to be made to non-extending lenders during the first year of the term period. However, Enerplus will be required to maintain certain minimum balances on deposit with the syndicate agent.

The Combined Facility is the legal obligation of EnerMark Inc. and is guaranteed by ERC. Although payments to Unitholders are subordinated to the Combined Facility, Unitholders have no direct liability to EnerMark Inc. or ERC should their revenues be insufficient to repay the bank loan. However, the bank debt has priority over claims of and distributions to the Unitholders.

Since a demand for payment, with respect to the operating facility, would be financed by the revolving facility, no portion of the operating facility has been considered as current.

4. FUND CAPITAL

(a)

Unitholders' Capital

Trust Units

Authorized: Unlimited Number of Trust Units

Issued: (thousands)	2001 Units	2001 Amount	2000 Units	2000 Amount	1999 Units	1999 Amount
Balance, beginning of year	40,925	$ 1,050,986	21,761	$ 592,693	18,540	$ 538,004
Issued for cash:						
Pursuant to public offerings	4,313	101,039	4,576	109,835	2,860	47,952
Pursuant to Option Plans	135	2,530	128	2,125	29	419
Pursuant to the exercise of warrants	1,197	33,319	17	404		
Pursuant to the expiry of warrants		2,846				
Issued pursuant to the deemed acquisition of Enerplus (Note 1)	20,863	582,364				

	2001		2000		1999	
Issued pursuant to the management agreement (Note 6)	173	5,000				
Distribution Reinvestment Plan	659	16,577	407	9,314	332	6,319
Corporate acquisitions (Note 7)						
Cabre Exploration Ltd.	1,267	31,846	9,897	248,825		
Western Star Exploration Ltd.			13	65		
Pursuit Resources Corp.			2,988	64,228		
Acquisition of property interests			1,138	23,509		
Redeemed for cash				(12)		(1)
Balance, end of year	69,532	$ 1,826,507	40,925	$ 1,050,986	21,761	$ 592,693

Warrants (thousands)	2001 Warrants	2001 Amount	2000 Warrants	2000 Amount	1999 Warrants	1999 Amount
Balance, beginning of year	3,045	$ 3,873		$		$
Issued during the year	390	496	3,065	3,873		
Exercised during the year	(1,197)	(1,523)	(17)			
Expired during the year	(2,238)	(2,846)	(3)			
Balance, end of year			3,045	$ 3,873		

On November 15, 2001, the Fund issued 4,312,500 Trust Units at a price of $24.75 per Trust Unit, pursuant to a short form prospectus to raise gross proceeds of $106,734,000 ($101,039,000 net of issuance costs).

In accordance with the reverse take-over method of purchase accounting, as described in Note 1, Trust Units and warrant amounts are those of EnerMark to June 21, 2001 together with changes in consolidated capital since that date. Numbers of Trust Units and Warrants issued to June 21, 2001 have been restated on the basis of the Merger Exchange Ratio. In addition, EnerMark is deemed to have acquired the net assets of Enerplus, in exchange for the 20,863,000 Trust Units of the Fund which were

outstanding at June 21, 2001, the date of the acquisition. The deemed Trust Unit gross consideration was recorded in the amount of $582,817,000 ($582,364,000 net of issuance costs).

Under the terms of an agreement for the provision of management, advisory and administrative services with a related party (Note 6), the Fund issued 172,500 Trust Units at a recorded value of $5,000,000.

Pursuant to an offer to purchase, which initially expired on December 21, 2000, and was subsequently extended, to January 8, 2001, the Fund acquired all of the outstanding common shares of Cabre Exploration Ltd. ("Cabre") (Note 7). As at December 31, 2000, the Fund had completed the acquisition of an 88.65% controlling interest in Cabre. The consideration for the controlling interest included the issuance of 9,897,000 Trust Units at $25.20 per Trust Unit for a value of $249,434,000 ($248,825,000 net of issuance costs) and 3,045,000 warrants at $1.27 per warrant for an ascribed value of $3,873,000. The warrants were exercisable into one Trust Unit at a price of $26.53 per Trust Unit at any time, until December 17, 2001.

The acquisition of the remaining 11.35% non-controlling interest of Cabre was completed on January 8, 2001 and resulted in the issuance of 1,267,000 additional Trust Units, at $25.20 per Trust Unit for gross consideration of $31,924,000 ($31,846,000 net of issuance costs) and 390,000 additional warrants at $1.27 per warrant for an ascribed value of $496,000.

On September 12, 2000, the Fund completed an offering of 4,575,850 Trust Units, at a price of $25.14 per Trust Unit, pursuant to a short form prospectus to raise gross proceeds of $115,061,000 ($109,835,000 net of issuance costs). The net proceeds of the offering were used to repay a portion of bank indebtedness incurred in connection with the acquisition of EBOC Energy Ltd. (Note 7).

On April 3, 2000, under the terms of an offer to purchase, the Fund successfully acquired Pursuit Resources Corp. (Note 7). The total consideration included the issuance of 2,988,000 Trust Units at $21.68 per Trust Unit for a value of $64,779,000 ($64,228,000 net of issuance costs).

On February 28, 2000, the Fund completed the acquisition of various property interests in the Hanna, Alberta area from an affiliate of a major Canadian pension fund. Consideration paid for the property interests included the issuance of 1,046,000 Trust Units recorded at $20.23 per Trust Unit. In addition, on August 30, 2000, the Fund acquired various property interests form two private corporations in exchange for 92,000 Trust Units valued at $25.78 per Trust Unit. Gross consideration for these acquisitions totalled $23,539,000 ($23,509,000 net of issuance costs).

Pursuant to an offer to purchase which was completed on January 7, 2000, the Fund acquired all of the issued and outstanding common shares of Western Star Exploration Ltd. (Note 7). The total consideration paid included the issuance of 12,874 Trust Units recorded at $21.67 per Trust Unit, for gross consideration of $279,000 ($65,000 net of issuance costs). Total consideration also included the issuance of 20,000 warrants. Each warrant was exercisable into one Trust Unit at a price of $23.12 per Trust Unit at any time until December 31, 2000, at which time 3,000 of the warrants outstanding expired.

Pursuant to an offering, which closed August 26, 1999, the Fund issued 1,211,000 Units at a price of $21.97 per Unit for gross proceeds of $26,606,000 ($25,076,000 net of issuance costs).

In February 1999 the Fund issued 1,649,000 Units at a price of $14.16 per Unit pursuant to an Offer of Rights to subscribe for Trust Units which expired February 26, 1999 for gross proceeds of $23,350,000 ($22,876,000 net of issuance costs).

In each of 2001, 2000, and 1999, Enerplus entered into joint venture agreements (the "Arrangements") with independent corporations (the "Corporations") whose sole purpose is to hold oil and natural gas interests earned under each Arrangement. The terms of the Arrangements require the Corporations to commit funds to be spent in joint venture with Enerplus as specified below. In addition, each Corporation has been granted the option to put its common shares to Enerplus at their fair value as determined by an independent evaluator on specified dates (the "Specified Dates"). Enerplus may elect to pay for the shares by way of cash or through the issuance of Trust Units of the Fund. If Trust Units are issued they are to be valued at 95% of their average closing price, for the 60 day period preceding the specified dates.

Drilling Fund Corporations	Approximate Funding Commitment	Specified Date
2001 Arrangement	$2.7 million	March 1, 2004
2000 Arrangement	$5.4 million	February 1, 2003
1999 Arrangement	$2.7 million	February 1, 2002

As at the date of preparation of these consolidated financial statements, the Corporation involved in the 1999 Arrangement may exercise its option to put its common shares to Enerplus. Enerplus has the option to acquire the shares of the Corporation for cash or through the issuance of Trust Units.

Trust Units are redeemable at any time, on demand by Unitholders, at 85% of the market price in effect from time to time. Redemptions cannot exceed $500,000 during any calendar month.

Pursuant to a revised monthly Distribution Reinvestment and Unit Purchase Plan, which became effective on March 30, 2001, Unitholders are entitled to reinvest cash distributions in additional Units of the Fund. Units are issued at a discount of 5% below the weighted average market price on the Toronto Stock Exchange for the twenty trading days preceding a distribution payment date and without service charges or brokerage fees. Unitholders are also entitled to make optional cash payments to acquire additional Units. Units issued pursuant to optional cash payments are issued on the same basis as reinvested cash distributions except no discount applies.

(b)

Trust Unit Option Plan

On August 22, 1996, a special resolution was passed approving the EnerMark Trust Unit Option Plan for trustees, directors, officers, employees of EnerMark or its affiliates, and related parties involved with the management of EnerMark. Enerplus had a similar plan for its directors, officers and employees. On June 21, 2001, in connection with the Merger, the vesting of certain EnerMark Trust Unit options was accelerated and the equivalent of in-the-money amounts on such vested options were paid out and have been included as a cost of the acquisition of Enerplus (Note 1). All outstanding EnerMark Trust Unit options were then cancelled and the 363,000 Enerplus Trust Unit Options outstanding as at June 21, 2001 were assumed.

Activity for the options issued pursuant to Option Plans are summarized as follows:

	2001		2000		1999	
	Number Of Options	**Weighted Average Exercise Price**	**Number Of Options**	**Weighted Average Exercise Price**	**Number Of Options**	**Weighted Average Exercise Price**
	(thousands except per Unit amounts)					
EnerMark Unit Options outstanding beginning of year	609	$ 24.28	740	$ 28.32	814	$ 37.05
Granted	639	$ 26.53	294	$ 22.31	318	$ 14.62
Exercised	(80)	$ 17.98	(128)	$ 16.59	(29)	$ 14.62
Cancelled	(321)	$ 26.47	(297)	$ 35.84	(363)	$ 36.94
Accelerated due to Merger	(847)	$ 25.72				
Enerplus Unit Options outstanding at June 21, 2001	363	$ 21.03				
Exercised	(55)	$ 21.94				
Cancelled	(44)	$ 20.47				
Outstanding at end of year	264	$ 20.93	609	$ 24.28	740	$ 28.32
Balance of Trust Units reserved but not issued			1,852		349	
Total Trust Units reserved as at the end of the year	264		2,461		1,089	

The following table summarizes information with respect to outstanding Unit Options as at December 31, 2001:

Number Outstanding at December 31, 2001	**Exercise prices**	**Expiry Date December 31**	**Number Exercisable at December 31, 2001**
(thousands)			**(thousands)**
27	$ 15.30	2002	27
52	$ 17.10	2003	23
185	$ 22.90	2004	49

Number Outstanding at December 31, 2001	Exercise prices	Expiry Date December 31	Number Exercisable at December 31, 2001
264	$ 20.93		99

(c)

Trust Unit Rights Incentive Plan

On June 21, 2001, a special resolution was passed to approve the adoption of a Trust Unit Rights Incentive Plan ("Incentive Plan") pursuant to which rights to acquire Enerplus Trust Units may be granted to trustees, directors, officers, employees, of the Fund or its affiliates and related parties involved in the management of the Fund. 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. No such reductions have occurred in 2001.

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

	2001		2000		1999	
	Number Of Rights	Exercise Price	Number Of Rights	Exercise Price	Number Of Rights	Exercise Price
	(thousands except per Unit amounts)					
Incentive Plan Rights outstanding beginning of year						
Granted	1,360	$ 24.50				
Cancelled	(42)	$ 24.50				
Outstanding at end of year	1,318	$ 24.50				
Balance of Trust Units reserved but not issued	1,422					
Total Trust Units reserved at the end of year	2,740					
Exercisable at December 31, 2001						

5. INCOME TAXES

(a)

The Fund

The Fund is an inter vivos trust for income tax purposes. As such, the Fund is taxable on any income which is not allocated to the Unitholders. The Fund intends to allocate all income to Unitholders. Should the Fund incur any income taxes, the funds available for distribution will be reduced accordingly.

During 2001, the Fund had taxable income of $181.3 million (2000 $69.1 million and 1999 $20.0 million) or $4.71 per Unit (2000 $2.44 per Unit and 1999 $0.956 per Unit) which was allocated to the Unitholders. Taxable income of the Fund is comprised of income on securities issued by EnerMark and royalty income, less deductions for Canadian oil and gas property expense ("COGPE"), which is claimed at a rate of 10% on a declining balance basis and the allowable portion of the cost of issuing new Trust Units during the period. Any losses which occur in the Fund must be retained in the Fund and may be carried forward and deducted from taxable income for a period of seven years. As at December 31, 2001, the Fund had no losses available for carry forward.

The amounts of COGPE and issue costs remaining in the Fund are as follows:

	2001		2000		1999	
	Per Unit	**Amount**	**Per Unit**	**Amount**	**Per Unit**	**Amount**
COGPE	$ 5.49	$ 381,563	$ 2.14	$ 87,294	$ 4.45	$ 96,993
Issue costs	0.14	10,063	0.17	7,681	0.23	4,800
Total	$ 5.63	$ 391,626	$ 2.31	$ 94,975	$ 4.68	$ 101,793

(b)

Corporate Subsidiaries

The provision for future income taxes arises from temporary differences in the recognition of revenues and expenses for income tax and accounting purposes. The temporary differences, tax effected at substantially enacted rates, comprising the future income tax liability are as follows:

	2001	2000
Excess of net book value of property, plant and equipment over the underlying tax basis	$ 350,754	$ 367,486
Future site restoration deductions	(17,643)	(14,318)
Other	449	(53)
Future income tax liability	$ 333,560	$ 353,115

The provisions for income taxes vary from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

	2001	2000	1999(1)
Net income before taxes	$ 153,516	$ 100,464	$ 22,348
Computed income tax expense (recovery) at substantially enacted rates of 42.62% (44.62% for 2000 and 1999)	$ 65,429	$ 44,827	$ 9,972
Increase (decrease) resulting from:			
Net income attributed to the Fund	(95,671)	(32,173)	(14,755)
Non-deductible crown royalties and other payments	43,309	29,166	11,279
Federal resource allowance	(43,658)	(26,975)	(9,935)
Non-deductible depletion			1,176
ARTC	(214)	(249)	(614)
Other	(670)	782	(2,080)
Future income taxes (recovery)	$ (31,475)	$ 15,378	$ (4,957)

	2001	2000	1999[1]

(1) See Note 2 (l)

6. RELATED PARTY TRANSACTIONS

Management, advisory and administration services are supplied to the Fund on a fee and cost reimbursement basis, pursuant to a new agreement with Enerplus Global Energy Management Company ("EGEM"), commencing on June 21, 2001, and prior thereto with EMR Resource Management Ltd., a wholly-owned subsidiary of EGEM. As at December 31, 2001, $7,406,000 was payable to EGEM, pursuant to this agreement.

Management fees equal to 2.2% of operating income to June 21, 2001 and 2.75%, thereafter, are reported on the Consolidated Statement of Income. Pursuant to the agreement, prior to June 21, 2001, fees of $302,000 earned in relation to certain property acquisitions and divestitures of Enerplus which are included in the cost of property, plant and equipment. Under the new agreement, acquisition and divestment fees were eliminated and replaced with a performance fee based on both the total return of the Fund and its

relative performance, as compared to other senior Canadian conventional oil and gas energy funds. For the year ended December 31, 2001, no amounts for performance fees are included in the determination of management fees as reported on the Consolidated Statement of Income. In conjunction with the Merger, EGEM received a minimum fee of 172,500 Enerplus Trust Units with an assigned value of $5,000,000. The fee was accounted for as a cost of the Merger.

Pursuant to a share purchase agreement related to the Merger, EnerMark Inc. acquired all of the outstanding common shares of ERC from EGEM resulting in ERC becoming a wholly-owned subsidiary of Enerplus. Consideration for the shares was $2,545,000 and is payable over a five year period ending September 2006, through a reduction in management fees. Of this amount, $509,000 has been classified as a current liability. The non-refundable fee advance and acquisition cost of the ERC shares has been included as a cost of the acquisition of Enerplus Resources Fund.

In addition to the transactions described above, Enerplus has entered into a financial instrument contract with an indirect subsidiary of El Paso Energy Corporation, the ultimate parent of EGEM, as described in Note 8.

7. CORPORATE ACQUISITIONS

(a) ***Cabre Exploration Ltd.***

Pursuant to an offer to purchase, initially expiring December 21, 2000 and subsequently extended to January 8, 2001, Enerplus acquired all of the outstanding common shares of Cabre, a public Alberta corporation, of which Enerplus held an 88.65% controlling interest as at December 31, 2000.

The 88.65% controlling interest in Cabre was acquired for a total consideration of $259,878,000 which consisted of 9,897,000 Trust Units with a recorded value of $249,434,000, costs associated with the acquisition of $6,571,000 and 3,045,000 warrants excercisable into one Trust Unit at a price of $26.53 until December 17, 2001 with a recorded value of $3,873,000. A future tax cost of $46,077,000 plus an amount of $64,510,000 by which the total consideration exceeded the proportionate carrying value recorded in the accounts of Cabre has been allocated as an increase to property, plant and equipment.

The acquisition of the remaining 11.35% in common shares of Cabre was completed on January 8, 2001 for a total consideration of $32,420,000 which consisted of 1,267,000 Trust Units with a recorded value of $31,924,000 and 390,000 warrants excercisable into one Trust Unit at a price of $26.53 until December 17, 2001 with a recorded value of $496,000. A future tax cost of $11,396,000 plus an amount of $7,407,000 by which the total consideration exceeded the proportionate carrying value recorded in the accounts of Cabre has been allocated as an increase to property, plant and equipment.

The net assets acquired and liabilities assumed for the completed acquisition are summarized as follows:

	88.65% December 31, 2000	11.35% January 8, 2001	100.00% Total
Property, plant and equipment	$ 484,550	$ 18,803	$ 503,353
Working capital deficiency	(21,424)		(21,424)
Long-term debt assumed	(18,213)		(18,213)
Site restoration and abandonment	(19,196)		(19,196)
Future income taxes	(140,826)	(11,396)	(152,222)
Non-controlling interest	(25,013)	25,013	
Net assets acquired	$ 259,878	$ 32,420	$ 292,298

Cabre was formally amalgamated effective January 17, 2001 with EnerMark Inc. and the amalgamated entity was continued under the name EnerMark Inc.

(b)

EBOC Energy Ltd.

On September 1, 2000, the Fund acquired all outstanding common shares of EBOC Energy Ltd. ("EBOC") a private Alberta corporation for total consideration of $148,217,000 comprised of $143,585,000 in cash and related costs of $4,632,000. A future income tax cost of $84,882,000 plus an amount of $105,761,000 by which the total consideration paid exceeded the carrying value recorded in the accounts of EBOC has been allocated as an increase to property, plant and equipment. The net assets acquired and liabilities assumed are summarized as follows:

Property, plant and equipment	$ 263,608
Working capital deficiency	(2,947)
Long-term debt assumed	(6,428)
Site restoration and abandonment	(287)
Future income taxes	(105,729)
Net assets acquired	$ 148,217

EBOC was amalgamated effective September 1, 2000 with EnerMark Inc. and the amalgamated entity was continued under the name EnerMark Inc.

(c)

Pursuit Resources Corp.

Pursuant to a take-over bid which was completed on April 3, 2000, the Fund acquired all outstanding common shares of Pursuit Resources Corp. ("Pursuit") a public Alberta corporation. The total consideration of $81,670,000 consisted of 2,988,000 Trust Units of the Fund with a recorded value of $64,779,000, cash of $14,693,000 and costs associated with the acquisition in the amount of $2,198,000. A future income tax cost of $29,821,000 plus an amount of $37,060,000 by which the total consideration paid exceeded the carrying value recorded in the accounts of Pursuit has been allocated as an increase to property, plant and equipment. The net assets acquired and liabilities assumed are summarized as follows:

Property, plant and equipment	$ 159,213
Working capital	1,079
Long-term debt assumed	(37,195)
Site restoration and abandonment	(1,381)
Future income taxes	(40,046)
Net assets acquired	$ 81,670

Pursuit remained a wholly-owned subsidiary of EnerMark Inc. until July 1, 2000 when it was amalgamated with EnerMark Inc. and the amalgamated entity was continued under the name EnerMark Inc.

(d)

Western Star Exploration Ltd.

Pursuant to a take-over bid which was completed on January 7, 2000, the Fund acquired all outstanding common shares of Western Star Exploration Ltd. ("Western Star") a public Alberta corporation. The total consideration of $22,035,000 consisted of 12,874 Trust Units of the Fund with a recorded value of $279,000, cash of $21,251,000 and related costs of $505,000. Recipients of Trust Units also received 20,000 warrants, which were exercisable into one Trust Unit at a price of $23.12 per Trust Unit until December 31, 2000. The total consideration paid in excess of the carrying value recorded in the accounts of Western Star has been allocated as an increase to property, plant and equipment in the amount of $8,400,000. The net assets acquired and liabilities are summarized as follows:

Property, plant and equipment	$ 27,894
Working capital deficiency	(495)
Long-term debt assumed	(5,028)
Site restoration and abandonment	(336)
Net assets acquired	$ 22,035

Western Star remained a wholly-owned subsidiary of EnerMark Inc. until April 1, 2000 when it was amalgamated with EnerMark Inc. and the amalgamated entity was continued under the name EnerMark Inc.

(e)

Derrick Energy Corporation

Pursuant to a plan of arrangement which closed June 4, 1999, the Fund acquired all of the outstanding shares of Derrick Energy Corporation ("Derrick"), a public Alberta corporation, and immediately thereafter disposed of 80% of Derrick's petroleum and natural gas assets to predecessor companies of ERC. The total net consideration of $2,925,000 consisted of $26,888,000 in cash and $73,000 in costs associated with the arrangement less disposal proceeds of $24,036,000. The carrying value recorded in the accounts of Derrick exceeded the total consideration paid net of disposal proceeds by $2,575,000

and has been allocated as a decrease to property, plant and equipment. The net assets acquired and liabilities assumed are summarized as follows:

Property, plant and equipment	$ 3,748

Working capital deficiency		(776)
Site restoration and abandonment		(47)
Net assets acquired	$	2,925

Derrick remained a wholly-owned subsidiary of EnerMark Inc. until January 1, 2000 when it was amalgamated with EnerMark Inc. and the amalgamated entity was continued under the name EnerMark Inc.

8. FINANCIAL INSTRUMENTS

The Fund's financial instruments that are included in the balance sheet are comprised of current assets, current liabilities, the bank debt and the long-term payable to related party.

The fair market values of these instruments approximate their carrying amount due to the short-term maturity of these instruments and the variable interest rates applied to the bank debt. Virtually all of the Fund's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks.

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 December 31, 2001. 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.

CRUDE OIL

As at December 31, 2001 Enerplus has three separate three-way financial option transactions that are designed to reduce a downward impact of crude oil prices of 3,675 bbls/day of crude oil production. The

total cost to be amortized in 2002 is $859,000. The fair value of the financial crude oil hedges as at December 31, 2001 reflects an unrealized gain of $274,000.

Financial Instrument Type	Daily Volumes bbls/day	WTI US$/bbl Sold Call	WTI US$/bbl Purchased Put	WTI US$/bbl Sold Put
Crude Oil 2002				
Financial Contracts				
3-Way option	1,500	$ 27.00	$ 19.50	$ 16.00
3-Way option[(1)]	1,500	$ 25.00	$ 19.50	$ 17.00
3-Way option	675	$ 27.00	$ 19.50	$ 17.00
Total	3,675			

(1) The counterparty to one of the 3-way crude oil options above, is a subsidiary of El Paso Energy Corporation which is the ultimate parent of EGEM (refer to Note 6). The remaining option premiums for these instruments are $276,000 and are being amortized over their remaining terms.

NATURAL GAS

As at December 31, 2001 Enerplus has physical and financial contracts in place on approximately 57 MMcf/day of natural gas in 2002 and 20 MMcf/day of natural gas in 2003. The remaining costs to be amortized in 2002 are $2,032,000 and $1,696,000 in 2003. The fair value of the financial natural gas hedges as at December 31, 2001 reflects an unrealized loss of $711,000.

The following table summarizes the commodity risk management positions as at December 31, 2001:

		AECO $/Mcf				
Financial Instrument Type	**Annualized Daily Volumes Mcf/d**	**Sold Call**	**Purchased Put**	**Sold Put**	**Fixed Price**	**Escalated Price**
Natural Gas 2002						
Physical contracts	6,002				$ 2.64	
Physical contracts	1,967					$ 2.01
	7,969					
Financial contracts						
Collar[(1)]	9,084	$ 5.27	$ 3.69			
Put[(1)]	9,084		$ 3.69			
Swap	3,792		$ 2.90			
Collar	7,584	$ 4.22	$ 3.43			
Collar	5,688	$ 4.81	$ 3.43			
Collar	14,220	$ 4.22	$ 3.32			
Total	57,421					
Natural Gas 2003						
Physical contracts	2,369				$ 2.64	
Physical contracts	1,967					$ 2.23
	4,336					
Financial contracts						
Collar[(1)]	5,922	$ 5.27	$ 3.69			
Put[(1)]	5,922		$ 3.69			
Swap	3,792		$ 2.90			
Total	19,972					
Natural Gas 2004						
Physical contracts	1,967					$ 2.33
Financial contracts swaps	3,160		$ 2.90			
Total	5,127					
Natural Gas 2005 2010						
Physical	1,967					$ 2.43

(1) The counterparty to these natural gas collars and puts, is a subsidiary of El Paso Energy Corporation which is the ultimate parent of EGEM (refer to Note 6). The option premiums for these instruments are $3,728,000 and are being amortized over their remaining terms.

9. RESTATEMENT OF PRIOR YEARS DISTRIBUTION PAYABLE TO UNITHOLDERS

The comparative consolidated balance sheets for December 31, 2000 and 1999 and consolidated statements of accumulated cash distributions for each of the years then ended have been restated to recognize a current liability to Unitholders representing the monthly distribution that was declared on December 20, 2000 and December 20, 1999 and paid on January 20, 2001 and January 20, 2000, respectively. The effect of this change is to increase distributions payable to Unitholders and increase accumulated cash distributions by $18,925,000 and $7,547,000 as at December 31, 2000 and 1999, respectively. There is no current or prior effect to the Fund's cash flow or earnings.

10. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Fund's consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These principles, as they pertain to the Fund's consolidated statements, differ from United States generally accepted accounting principles ("U.S. GAAP") as follows:

(a) Under U.S. GAAP, for Securities and Exchange Commission registrants following full cost accounting, the carrying value of petroleum and natural gas properties and related facilities, net of deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at 10 percent (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproven properties. Under Canadian GAAP, the Ceiling Test is calculated without application of a discount factor, but includes general and administration, management fees and interest expense.

Where the amount of a Ceiling Test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion, depreciation and amortization will differ in subsequent years. As at December 31, 2001, the application of the Ceiling Test under U.S. GAAP resulted in a write down of $744.3 million ($458.4 million after tax) of capitalized costs. At December 31, 2000 and 1999, the application of the Ceiling Test under U.S. GAAP did not result in a write down of capitalized costs. Under Canadian GAAP, the application of the Ceiling Test did not result in a write down for the years 2001, 2000 and 1999.

(b) SFAS 123, "Accounting for Stock-based Compensation", establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by SFAS 123, Enerplus has elected to continue to follow the intrinsic value method of accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board Opinion 25 ("APB 25"). Since all Unit Options and Trust Unit Rights were granted with an exercise price equal to the market price at the date of the grant, no compensation cost has been charged to income. Had compensation cost for Enerplus stock options been determined based on the fair market value at the grant dates of the awards consistent with methodology prescribed by SFAS 123, Enerplus net income (loss) and net

income (loss) per Unit for years ended December 31, 2001, 2000 and 1999 would have been the pro forma amounts indicated below:

	Years ended December 31,		
	2001	2000	1999
	(thousands except per Unit amounts)		
Net income (loss):			
As reported under U.S. GAAP	$ (261,288)	$ 98,261	$ 48,024
Pro forma	(262,191)	96,813	46,627
Net income (loss) per Unit			

	Years ended December 31,		
Basic			
As reported under U.S. GAAP	$ (4.76)	$ 3.66	$ 2.34
Pro forma	$ (4.78)	$ 3.61	$ 2.27
Diluted			
As reported under U.S. GAAP	$ (4.76)	$ 3.65	$ 2.33
Pro forma	$ (4.78)	$ 3.60	$ 2.26

The estimated fair value of the options issued under the Unit Options Plan and the Trust Unit Right Incentive Plan was determined using the Black-Scholes model and the following assumptions:

	2001	2000	1999
Risk-free interest rate	2.35%	5.98%	5.07%
Estimated hold period prior to exercise	3 years	3 years	3 years
Volatility in the market price of the Trust Units	24.5%	33.5%	36.3%
Estimated monthly cash distributions	$ 0.11/Unit	$ 0.07/Unit	$ 0.05/Unit

The weighted average fair value of options granted in 2001, 2000 and 1999 was $0.75, $0.80 and $0.61 per option, respectively.

As the exercise price of the rights is subject to downward revisions from time to time, the rights plan is a variable compensation plan under U.S. GAAP. Accordingly, compensation expense is determined as the excess of the market price over the exercise price of the rights at the end of each reporting period and is deferred and recognized in income over the vesting period of the rights. At December 31, 2001, no downward revision in exercise price had occurred and no compensation expense has been recognized for the rights. Due to the nature of the rights it is not possible to estimate the fair value of the rights.

(c)

U.S. GAAP requires the reporting of comprehensive income in addition to net earnings. Comprehensive income includes net income plus certain other items not included in net income. The Fund's Comprehensive income is the same as its net income.

(d)

Under U.S. GAAP the measurement date for acquisitions is the date the acquisition is announced. Under Canadian GAAP the measurement date for the acquisition is the closing date. Under U.S. GAAP, Unitholders' capital and property, plant and equipment has been increased by $37.3 million in 2001 and decreased by $7.8 million in 2000 for differences in the value of Trust Units issued to effect certain acquisitions.

(e)

Effective January 1, 2000, the Fund adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for future income taxes and changed from the deferral method to the liability method. This liability method differs from U.S. GAAP due to the application of transitional provisions and the accounting for certain Canadian income tax credits and allowances. In 1999, under U.S. GAAP future income taxes and property, plant and equipment was increased by $4.5 million.

(f)

Effective January 1, 2001, for U.S. reporting purposes, the Fund adopted Statement of Financial Accounting Standards ("SFAS") No. 133. "Accounting for Derivative Instruments and Hedging Activities". SFAS 133 establishes accounting and reporting standards requiring that all derivative instruments (including derivative instruments embedded in other contracts), as defined, be recorded in the balance sheet as either an asset or a liability measured at fair value and requires that changes in fair value be recognized currently in income unless specific hedge accounting criteria are met. There are no similar standards under Canadian GAAP.

Hedge accounting treatment allows unrealized gains and losses to be deferred in other comprehensive income (for the effective portion of the hedge) until such time as the forecasted transaction occurs and requires that an entity formally document, designate and assess effectiveness of derivative instruments that receive hedge accounting treatment. The Fund has chosen to not formally document and designate its financial derivatives outstanding at December 31, 2001 and 2000 as hedges for U.S. GAAP purposes.

(g)

The following supplemental pro forma information has been prepared using U.S. GAAP and gives effect to the Merger as if it had occurred on January 1 of each of the following years:

	December 31, 2001	December 31, 2000
	(unaudited)	(unaudited)
Revenues, net of royalties	$ 604,443	$ 408,747
Net income	$ (191,199)	$ 133,435
Net income per Unit		
Basic	$ (2.95)	$ 2.80
Fully diluted	$ (2.95)	$ 2.79

(h)

Recent Developments in U.S. Accounting Standards

In July 2001, the Financial Accounting Standards Board ("FASB") issued SFAS 141, "Business Combinations", and SFAS 142, "Goodwill and Other Intangible Assets." SFAS 141 requires the purchase method of accounting to be used for all business combinations initiated after June 30, 2001. SFAS 142 requires that goodwill and intangible assets with an indefinite useful life no longer be amortized, but instead tested for impairment at least annually. SFAS 142 is effective for fiscal years beginning after December 15, 2001, except that goodwill and intangible assets acquired after June 30, 2001, will be subject immediately to the amortization and non-amortization provisions of SFAS 142. At this time, the adoption of SFAS 141 and SFAS 142 have no impact on the Fund's financial statements.

In June 2001, the FASB issued SFAS 143, "Accounting for Asset Retirement Obligations". SFAS 143 requires liability recognition for retirement obligations associated with tangible long-lived assets. The obligations included within the scope of SFAS 143 are those for which the Fund faces a legal obligation for settlement. The initial measurement of the asset retirement obligation is to be at fair value. The asset retirement cost equal to the fair value of the retirement obligation is to be capitalized as part of

the cost of the related long-lived asset and amortized to expense over the useful life of the asset. SFAS 143 is effective for all fiscal years beginning after June 15, 2002. The total impact on the Fund's financial statements has not yet been determined.

The application of U.S. GAAP would have the following effects on net income as reported:

	2001	2000	1999
	($ thousands except per Unit amounts)		
Net income as reported in the Consolidated Statement of Income	$ 180,269	$ 82,150	$ 25,754
Adjustments, net of applicable income tax			
Write-down of property, plant and equipment	(458,474)		
Depletion, depreciation and amortization	17,168	16,111	22,270
Unrealized gain on financial derivatives	(251)		
Net income (loss) and comprehensive income (loss)	$ (261,288)	$ 98,261	$ 48,024

	2001	2000	1999
Net income (loss) per Unit			
Basic	$ (4.76)	$ 3.66	$ 2.34
Diluted	$ (4.76)	$ 3.65	$ 2.33
Weighted average number of Units outstanding			
Basic	54,907	26,841	20,532
Diluted	54,956	26,928	20,607

The application of U.S. GAAP would have the following effects on the balance sheet as reported:

	Canadian GAAP	Increase (decrease)	U.S. GAAP
		($ thousands)	
December 31, 2001			
Financial derivative assets	$	$ 274	$ 274
Property, plant and equipment, net	2,178,316	(1,018,610)	1,159,706
Financial derivative liabilities		711	711
Future income taxes	333,560	(406,556)	(72,996)
Unitholders' capital	1,826,507	29,626	1,856,133
Accumulated income	324,570	(642,117)	(317,547)
December 31, 2000			
Property, plant and equipment, net	1,483,293	(339,588)	1,143,705
Future income taxes	353,115	(131,270)	221,845
Unitholders' capital	1,054,859	(7,758)	1,047,101
Accumulated income	144,301	(200,560)	(56,259)
December 31, 1999			
Property, plant and equipment, net	556,285	(359,183)	197,102
Future income taxes	33,593	(126,335)	(92,742)
Accumulated income	$ 78,328	$ (232,848)	$ (154,520)

11. EVENTS SUBSEQUENT TO DECEMBER 31, 2001

(a)

On June 19, 2002, Enerplus issued senior, unsecured notes (the "Notes") in the amount of US$175,000,000. The Notes have a final maturity date 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, Enerplus 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 as 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 $1,892,000, 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 operating line. Various borrowings are available under the Facilities including prime rate based and banker's acceptance loans.

(b)

On August 8, 2002 the Fund acquired a 16% working interest in Oil Sands Lease #24 (also known as the Joslyn Creek Lease) for $16.4 million and the assumption of $4.1 million in contingent project debt. The contingent project debt was comprised of $3,360,000 of principal and approximately $740,000 in accrued interest. Interest is accrued at the Bank of Canada prime business rate and is not compounded. The debt is contingent on both production and pricing hurdles with respect to development on the lease. It is too early in the development of this project to determine if these hurdles will be satisfied.

(c)

On September 12, 2002, Enerplus closed an equity offering of 4,750,000 trust units at a price of $26.85 per trust unit for gross proceeds of $127,538,000 (net $120,886,000).

(d)

On October 3, 2002, the Fund announced that it had acquired all of the issued and outstanding shares of Celsius Energy Resources Ltd., a private oil and gas company, for total cash consideration of approximately $165.9 million including working capital adjustments. The acquisition will be accounted for by the purchase method with the results of operations included in the financial statements of the Fund from the closing date of October 21, 2002.

ENERPLUS RESOURCES FUND

SFAS NO. 69 SUPPLEMENTAL RESERVE INFORMATION

(Unaudited)

The following disclosures have been prepared in accordance with SFAS No. 69 "Disclosures about Oil and Gas Producing Activities":

Oil and Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and the Fund's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Fund's share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2001 no major discovery or other favourable or adverse event is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

Results of Operations for Producing Activities

The following table sets forth revenue and direct cost information relating to the Fund's oil and gas producing activities for the years ended December 31.

	2001	2000	1999
		(Thousands)	
Revenue			
Sales[2]	$ 506,719	$ 262,239	$ 137,396
Deduct			
Production Costs	120,082	54,997	37,228
Depletion, depreciation and amortization and valuation provision	910,486	52,956	26,452
Results of operations from producing activities	$ (523,849)	$ 154,286	$ 73,716

(1) The costs in this schedule exclude corporate overhead, interest expense and other costs which are not directly related to producing activities.

(2) Sales are net of royalties and third party obligations.

**COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION,
EXPLORATION AND DEVELOPMENT ACTIVITIES**

Costs incurred in oil and gas producing activities for the years ended December 31 are as follows:

	2001	2000	1999
		(Thousands)	
Acquisition Costs of Proved Properties	$ 767,216	$ 685,979	$ 13,591
Development Costs	141,509	39,053	19,557
	$ 908,725	$ 725,032	$ 33,148

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties.

Development costs include the costs of drilling and equipping development wells and facilities to extract, treat and gather and store oil and gas, along with an allocation of overhead.

There were no oil and gas property costs not being amortized in any of the years presented.

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

The capitalized costs and related accumulated depreciation, depletion and amortization, including impairments, relating to the Fund's oil and gas exploration, development and producing activities at December 31 consist of:

	2001	2000	1999
		(Thousands)	
Proved oil and gas properties	$ 2,654,711	$ 1,784,127	$ 782,840
Less accumulated depletion, depreciation and amortization	1,500,037	643,986	592,072

	2001	2000	1999
Net capitalized costs	$ 1,154,674	$ 1,140,141	$ 190,768

Oil and Gas Reserve Information

All of the Fund's proved oil, natural gas liquids, and natural gas reserves are located in Canada, primarily in the provinces of Alberta, British Columbia, and Saskatchewan. The Fund's proved developed and undeveloped reserves after deductions of royalties are summarized below:

	Crude Oil and NGLs (MMbbls)	Natural Gas (Bcf)
NET PROVED DEVELOPED AND UNDEVELOPED RESERVES AFTER ROYALTIES		
End of year 1998	**44.6**	**252.1**
Revision of previous estimates	0.4	6.3
Purchase of reserves in place	1.9	9.4
Sales of reserves in place	(0.1)	(15.2)
Discoveries and extensions	0.3	1.0
Production	(4.0)	(20.0)
End of year 1999	**43.1**	**233.6**
Revision of previous estimates	(1.9)	(57.0)
Purchase of reserves in place	20.8	354.1
Sales of reserves in place	(0.5)	(6.2)
Discoveries and extensions		
Production	(4.3)	(28.3)
End of year 2000 (EnerMark Income Fund)	**57.2**	**496.2**
End of year 2000 (Enerplus Resources Fund)	**44.1**	**246.3**
End of year 2000 (Combined)	**101.3**	**742.5**
Revision of previous estimates	(1.1)	60.8
Purchase of reserves in place		
EnerMark Income Fund	3.3	18.0
Enerplus Resources Fund (prior to June 21)	1.1	0.2
Combined	4.4	18.2
Sales of reserves in place		
EnerMark Income Fund	(3.6)	(12.6)
Enerplus Resources Fund (prior to June 21)	(1.0)	(4.6)
Combined	(4.6)	(17.2)
Discoveries and extensions		
Production	(8.9)	(59.4)
End of year 2001	**91.1**	**744.9**
NET PROVED DEVELOPED RESERVES AFTER ROYALTIES		
End of year 1998	33.5	190.6
End of year 1999	32.9	168.0
End of year 2000 (EnerMark Income Fund)	50.1	395.5

	Crude Oil and NGLs (MMbbls)	Natural Gas (Bcf)
End of year 2000 (Enerplus Resources Fund)	42.3	185.8
End of year 2000 (Combined)	92.4	581.3
End of year 2001	83.6	605.5

(1) Net after royalty reserves are the Fund's lessor royalty, overriding royalty, and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production.

(2) Reserves are the estimated quantities of crude oil, natural gas and related substances anticipated from geological and engineering data to be recoverable from known accumulations, from a given date forward, by known technology, under existing operating conditions and prices in effect at year end.

(3) Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

(4) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

The following information has been developed utilizing procedures described by SFAS No. 69 and based on crude oil and natural gas reserve and production volumes estimated by the independent engineering consultants of the Fund. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating the Fund or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Fund's reserves.

The future cash flows presented below are based on sales prices, cost rates, and statutory income tax rates in existence as of the period end date. It is expected that material revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2001 was based on a crude price of $30.35/Bbl and natural gas price of $3.75/Mcf. The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2000 was based on the Fund's crude oil price of $50.63/Bbl and natural gas price of $7.89/Mcf. The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 1999 was based on the Fund's crude oil price of $27.51/Bbl and natural gas price of $2.93/Mcf.

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Fund's crude oil and natural gas reserves at December 31, for the years presented.

2001	2000	1999
	(Millions)	

	2001	2000	1999
Future cash inflows	$ 2,558	$ 4,565	$ 1,077
Future production and development costs	(142)	(138)	(66)
Future net cash flows	2,416	4,427	1,011
Deduction: 10% annual discount factor	(1,154)	(2,113)	(488)
Standardized measure of discounted future net cash flows	$ 1,262	$ 2,314	$ 523

Changes in Standardized Measure of Discounted Future Cash Flow Relating to Proved Oil and Gas Reserves

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31 for the years presented.

	2001	2000	1999
		(Millions)	
Future discounted net cash flows at beginning of year	$ 2,314	$ 523	$ 432
Sales and transfer, net of production costs	(277)	(275)	(107)
Net change in sales and transfer prices, net of development and production costs	(1,860)	622	16
Extensions, discoveries and improved recovery, net of related costs			5
Revisions of quantity estimates	91	(251)	13
Accretion of discount	125	100	200
Sales of reserves in place	(89)	(33)	(21)
Purchase of reserves in place	1,033	1,718	35
Changes in timing of future cash flows and others	(75)	(90)	(50)
Net change income taxes			
End of Year	$ 1,262	$ 2,314	$ 523

(1) The schedules above are calculated using year-end prices, costs, statutory tax rates and existing proved oil and gas reserves. The value of exploration properties and probable reserves, future exploration costs, future changes in oil and gas prices and in production and development costs are excluded.

UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

COMPILATION REPORT

TO: The Directors of EnerMark Inc.

We have reviewed, as to compilation only, the accompanying unaudited pro forma consolidated statements of income and cash available for distribution of Enerplus Resources Fund (the "Fund") for the year ended December 31, 2001. These pro forma consolidated financial statements have been prepared for inclusion in the prospectus of the Fund dated November 22, 2002. In our opinion, the unaudited pro forma consolidated statements of income and cash available for distribution have been properly compiled to give effect to the transaction and the assumptions described in the notes thereto.

Calgary, Canada
November 22, 2002.

(Signed) DELOITTE & TOUCHE LLP
Chartered Accountants

COMMENTS FOR UNITED STATES READERS ON DIFFERENCE BETWEEN CANADIAN AND UNITED STATES REPORTING STANDARDS

The above opinion, provided solely pursuant to Canadian requirements, is expressed in accordance with standards of reporting generally accepted in Canada. Such standards contemplate the expression of an opinion with respect to the compilation of pro forma financial statements. Standards of reporting generally accepted in the United States do not provide for the expression of an opinion on the compilation of pro forma financial statements. To report in conformity with United States standards on the pro forma adjustments and their application to the pro forma financial statements would require an examination or review which would be substantially greater in scope than the review as to compilation only that we have conducted. Consequently, under United States standards, we would be unable to express any opinion with respect to the compilation of the accompanying unaudited pro forma consolidated statements of income and cash available for distribution.

Calgary, Canada
November 22, 2002.

(Signed) DELOITTE & TOUCHE LLP
Chartered Accountants

ENERPLUS RESOURCES FUND

PRO FORMA CONSOLIDATED STATEMENT OF INCOME

For the year ended December 31, 2001

(Unaudited)
($ thousands except per Unit amounts)

	Enerplus	Enerplus (pre-acquisition) 171 days	Adjustments		Pro Forma Consolidated
Revenues					
Oil and gas sales	$ 639,379	$ 122,343	$		$ 761,722
Crown royalties	(101,114)	(18,951)	(236)	(2a)	(120,301)
Freehold and other royalties	(31,546)	(7,149)	682	(2c)	(38,013)
	506,719	96,243	446		603,408
Interest and other income	858	177			1,035
	507,577	96,420	446		604,443
Expenses					
Operating	120,082	18,136			138,218
General and administrative	12,971	1,969			14,940
Management fee	9,323	2,743	412	(2b)	12,478
Interest	17,605	2,717			20,322
Depletion, depreciation and amortization	194,080	15,441	8,336	(2d)	217,857
	354,061	41,006	8,748		403,815
Income before taxes	153,516	55,414	(8,302)		200,628

	Enerplus	Enerplus (pre-acquisition) 171 days	Adjustments	Pro Forma Consolidated
Capital taxes	4,722	526		5,248
Future income tax provision (recovery)	(31,475)	274		(31,201)
Net income	$ 180,269	$ 54,614	$ (8,302)	$ 226,581
Net income per Unit				
Basic	$ 3.28			$ 3.50
Diluted	$ 3.28			$ 3.50

ENERPLUS RESOURCES FUND

PRO FORMA CONSOLIDATED STATEMENT OF CASH AVAILABLE FOR DISTRIBUTION

For the year ended December 31, 2001

(Unaudited)
($ thousands except per Unit amounts)

	Enerplus	Enerplus (pre-acquisition) 171 days	Adjustments	Pro Forma Consolidated
Net income	$ 180,269	$ 54,614	$ (8,302)	$ 226,581
Depletion, depreciation and amortization	194,080	15,441	8,336	217,857
Future income tax provision (recovery)	(31,475)	274		(31,201)
Site restoration and abandonment costs incurred	(2,628)	(633)		(3,261)
Funds flow from operations	340,246	69,696	34	409,976
Debt repayments related to capital expenditures	(48,850)	(8,150)		(57,000)
Enerplus cash flows	16,870	(16,870)		
Site restoration and abandonment costs incurred	2,628	633		3,261
Accruals	5,560	2,249		7,809
ARTC received		567		567
Cash available for distribution	$ 316,454	$ 48,125	$ 34	$ 364,613
Cash available for distribution per Unit	$ 5.67			$ 5.63

ENERPLUS RESOURCES FUND

NOTES TO THE PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2001

(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited pro forma consolidated financial statements (the "Pro Forma Statements") of Enerplus Resources Fund ("Enerplus") have been prepared by management of Enerplus in accordance with Canadian generally accepted accounting principles for inclusion in the prospectus of Enerplus dated November 22, 2002.

Effective June 21, 2001, Enerplus acquired all of the outstanding trust units of EnerMark Income Fund ("EnerMark") in exchange for 43,525,961 Trust Units of Enerplus, and all of the outstanding warrants to acquire EnerMark trust units were exchanged for 2,507,330 warrants to acquire Trust Units of Enerplus (the "Merger"). As a result of this exchange, the Unitholders of EnerMark became the controlling Unitholders of Enerplus. Accordingly, the Merger was accounted for as a reverse take-over. Under this form of purchase accounting, the net assets of Enerplus, rather than of EnerMark, are deemed to have been acquired.

The Pro Forma Statements of income and cash available for distribution have been prepared from the audited consolidated statements of income and cash available for distribution of Enerplus for the year ended December 31, 2001 and the financial records of Enerplus for the period from January 1, 2001 to June 21, 2001. The Pro Forma Statements should be read in conjunction with the audited consolidated financial statements of Enerplus for the year ended December 31, 2001. Other information which was available at the time of preparation of the Pro Forma Statements has also been considered. In the opinion of management, these Pro Forma Statements include all material adjustments necessary for a fair presentation.

The Pro Forma Statements are not necessarily indicative of the results of operations which would have occurred for the year ended December 31, 2001 had the Merger been effected on January 1, 2001 and, therefore, may not be representative of the operating results of future periods.

In preparing the Pro Forma Statements, no adjustments have been made to recognize any operating efficiencies or general and administrative cost savings which would be expected to occur as a result of combining the operations of Enerplus and EnerMark.

2. PRO FORMA ASSUMPTIONS AND ADJUSTMENTS

The pro forma consolidated statements of income and cash available for distribution for the year ended December 31, 2001 give effect to the Merger if it had occurred on January 1, 2001.

The accounting policies used in preparing the Pro Forma Statements are in accordance with those disclosed in the audited consolidated financial statements for Enerplus for the fiscal year ended December 31, 2001.

The Pro Forma Statements give effect to the following assumptions and adjustments:

(a) Enerplus' Alberta Royalty Tax Credit ("ARTC") for the period from January 1, 2001 to June 21, 2001 has been eliminated.

(b) Management fees have been adjusted to reflect the change in the management agreement between Enerplus and Enerplus Global Energy Management Company and have been provided for at 2.75% of oil and gas revenues plus ARTC, net of Crown, freehold and other royalties and operating expenses in accordance with the new management agreement.

(c) Freehold and other royalties have been adjusted to reflect the acquisition of Enerplus Energy Services Ltd.'s residual royalty interest of 1% by EnerMark Inc.

(d) The provision for depletion, depreciation and amortization has been adjusted as a result of the increase in property, plant and equipment.

3. PER UNIT INFORMATION

Pro forma per Unit information has been calculated using the weighted average number of Units outstanding as follows:

Basic	64,762
Diluted	64,811

4. APPLICATION OF UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The application of United States generally accepted accounting principles ("U.S. GAAP") would have the following effects on the pro forma combined statement of operations:

	Pro Forma December 31, 2001 (thousands)
Pro forma consolidated net income under Canadian GAAP	$ 226,581
Adjustments under U.S. GAAP[1]	(417,780)
Pro forma loss under U.S. GAAP	$ (191,199)
Loss per Unit:	
Basic	$ (2.95)
Diluted	$ (2.95)

(1) These adjustments reflect those made in the December 31, 2001 U.S. GAAP reconciliation adjusted for the pro forma U.S. GAAP depletion rate.

APPENDIX A

ENERPLUS RESERVES INFORMATION

Enerplus Reserves

Sproule Associates Limited, a large, established Canadian firm of independent petroleum engineers, has evaluated properties which comprise approximately 86% of Enerplus' proved developed producing crude oil and gas reserve value discounted at 12%, and 83% of Enerplus' proved plus probable oil and gas reserves value discounted at 12%. Enerplus has evaluated the balance of the properties using similar evaluation parameters, including the same escalated price forecasts utilized by Sproule. Our evaluations of these properties are included as "minor" properties in the Sproule Report. The constant price cases contained herein were extracted from a separate report prepared by Sproule dated March 7, 2002 which was based upon the escalated case Sproule Report.

In preparing its report, Sproule obtained basic information from Enerplus, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the Sproule Report is based, was obtained from public records, other operators and from Sproule's non-confidential files. Information concerning the extent and character of ownership of Enerplus' interests and the accuracy of all factual data supplied to Sproule by third parties was accepted by Sproule as represented and neither title searches nor field inspections were conducted.

Enerplus follows the Canadian practice of reporting gross production and reserve volumes, which are prior to the deduction of royalties and similar payments. In the United States, production and reserve volumes are reported after deducting these amounts. The Canadian practice of using escalating prices and costs when estimating the quantities of reserves is also followed by Enerplus. In the United States, reserve estimates are calculated using prices and costs held constant at amounts in effect at the date of the reserve report. Enerplus also follows the Canadian practice of using "Established Reserves", which include proved reserves and the probable reserves portion that has been reduced by a risk factor of 50%. As a consequence, our production volumes and reserve estimates may not be comparable to those made by United States companies. Please read "Presentation of Our Reserve Information."

The following is a summary, as at January 1, 2002, of Enerplus' crude oil, NGLs and natural gas reserves attributable to Enerplus' properties and the present worth value of the estimated future net cash flows associated with such reserves, based on escalated and constant price and cost assumptions. The tables summarize the data contained in the evaluations and as a result may contain slightly different numbers than the evaluations due to rounding. **All future cash flows are stated prior to provision for income taxes, interest, general and administrative expenses and management fees and indirect costs and after deduction of royalties and estimated future capital expenditures. It should not be assumed that the present worth of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of Enerplus' crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein. The probable additional reserve volumes and the present value of estimated future cash flows from such reserves as shown in the tables have been reduced by a factor of 50% to account for risk.**

Oil and Natural Gas Reserves and Present Value of Estimated Future Cash Flows Including ARTC Based on Escalated Price Assumptions(11)

	Working Interest Reserves(1)						Present Value of Estimated Future Net Cash Flow, $000 Discounted at Rates of:			
	Gross			Net						
	Oil MBbls	Gas MMcf	NGLs MBbls	Oil MBbls	Gas MMcf	NGLs MBbls	0%	10%	15%	20%
Proved Reserves(2)										
Developed Producing(3)(4)	86,770	722,692	13,685	78,085	570,157	9,567	2,992,588	1,376,940	1,116,058	946,568
Developed Non-Producing(3)(5)	620	58,791	512	540	47,233	352	157,757	78,807	63,970	54,201
Undeveloped(6)	7,457	169,650	1,917	6,311	142,109	1,347	401,713	170,532	118,996	84,367
Total Proved Reserves	94,847	951,133	16,114	84,936	759,499	11,266	3,552,058	1,626,279	1,299,024	1,085,136
Probable Reserves at 50%(7)	18,821	130,345	2,337	15,830	106,940	1,657	644,955	159,099	106,027	75,323
Established Reserves	113,668	1,081,478	18,451	100,766	866,439	12,923	4,197,013	1,785,378	1,405,051	1,160,459

Oil and Natural Gas Reserves and Present Value of Estimated Future Cash Flows Including ARTC Based on Constant Price Assumptions(12)

	Working Interest Reserves(1)						Present Value of Estimated Future Net Cash Flow, $000 Discounted at Rates of:			
	Gross			Net						
	Oil MBbls	Gas MMcf	NGLs MBbls	Oil MBbls	Gas MMcf	NGLs MBbls	0%	10%	15%	20%
Proved Reserves(2)										
Developed Producing(3)(4)	81,222	708,955	13,485	73,302	558,990	9,432	2,040,855	1,088,148	904,741	781,039
Developed Non-Producing(3)(5)	604	57,899	508	527	46,461	349	110,681	62,525	52,084	44,929
Undeveloped(6)	7,397	166,003	1,730	6,320	139,485	1,218	265,004	111,269	74,803	49,828

	Working Interest Reserves(1)									
Total Proved Reserves	89,223	932,857	15,723	80,149	744,936	10,999	2,416,540	1,261,942	1,031,628	875,796
Probable Reserves at 50%(7)	16,662	129,770	2,334	14,138	106,548	1,656	336,976	100,586	67,464	47,619
Established Reserves	105,885	1,062,627	18,057	94,287	851,484	12,655	2,753,516	1,362,528	1,099,092	923,415

(1) "Gross Reserves" are the remaining reserves owned by Enerplus, before deduction of any royalties. "Net Reserves" are the gross remaining reserves of the properties in which Enerplus has an interest, less all royalties and interests owned by others.

(2) "Proved Reserves" are those quantities of oil, natural gas and natural gas by-products, which, upon analysis of geological and engineering data, appear with a high degree of certainty to be recoverable at commercial rates in the future from known oil and natural gas reservoirs under current economic and operating conditions for reserves based on constant price and cost assumptions, and presently anticipated economic and operating conditions for the reserves based on escalated price and cost assumptions. There is relatively little risk with these reserves.

(3) "Proved Developed Reserves" are Proved Reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

(4) "Proved Developed Producing Reserves" are Proved Reserves which are presently being produced from completion intervals open for production in existing wells. As at January 1, 2002, these reserves were on production and represent approximately 76% of Enerplus' total proved and risked probable oil and NGLs reserves and 67% of Enerplus' total proved and risked probable natural gas reserves.

(5) "Proved Developed Non-producing Reserves" are Proved Reserves which are currently not being produced but do exist in completed intervals but not producing in existing wells, behind casing in existing wells or at minor depths below the present bottom of existing wells. These Proved Reserves are expected to be produced through the existing wells in the predictable future. These reserves are classified as Proved Developed Reserves since the cost of making such reserves available for production is relatively small compared to the cost of a new well.

(6) "Proved Undeveloped Reserves" are Proved Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where relatively major expenditures are required for the completion of these wells or for the installation of processing and gathering facilities prior to the production of these reserves. Reserves on undrilled acreage are limited to those drilling units offsetting productive wells that are reasonably certain of production when drilled.

(7) "Probable Reserves" are those reserves which may be recoverable as a result of the beneficial effects which may be derived from the future institution of some form of pressure maintenance or other secondary recovery method, or as a result of a more favourable performance of the existing recovery mechanism than that which would be deemed proved at the present time, or those

reserves which may reasonably be assumed to exist because of geophysical or geological indications and drilling done in regions which contain proved reserves. **Probable reserve values for the petroleum and natural gas properties and the future net cash flow from probable reserves have been discounted by a factor of 50% to account for the risk associated with the probability of obtaining production from such reserves**.

(8) Includes the ARTC based on current legislation in place on January 1, 2002.

(9) Natural gas reserves are reported at a base pressure of 14.65 pounds per square inch and a base temperature of 60^{o} F.

(10) Prices for oil F.O.B. Edmonton are based upon 40^{o} API oil having less than 0.4% sulphur. Prices for natural gas are based upon a base pressure of 14.65 pounds per square inch and base temperature of 60^{o}F. The wellhead oil prices were adjusted for quality and transportation to reflect the actual price to be received. The natural gas prices were adjusted, where necessary, only for heating values and the differing costs of service applied by various purchasers. The natural gas liquids prices were adjusted to reflect current prices received.

(11)

The escalated price and cost case assumes the continuance of current laws and regulations, and any increase in selling prices also takes inflation into account. The product price forecasts used are as follows:

			Natural Gas Liquids				Natural Gas		
				Edmonton			Plant Gate		
Year	**WTI Cushing Oklahoma**	**Edmonton Par Price 40° API**	**Plant Gate Ethane**	**Propane**	**Butane**	**Pentanes**	**Alberta**	**Sask.**	**B.C.**
	(US$/Bbl)	**($/Bbl)**	**($/Bbl)**	**($Bbl)**	**($/Bbl)**	**($/Bbl)**	**($/MMBTU)**	**($/MMBTU)**	**($/MMBTU)**
2002	19.90	29.86	10.54	16.73	17.81	30.59	3.63	3.70	3.75
2003	20.64	30.96	12.04	17.34	18.46	31.71	4.18	4.25	4.30
2004	21.12	31.67	12.08	17.74	18.88	32.43	4.19	4.26	4.26
2005	21.44	32.15	12.08	18.01	19.17	32.93	4.18	4.26	4.26
2006	21.76	32.65	12.29	18.29	19.47	33.44	4.25	4.34	4.34
2007	22.08	33.14	12.51	18.56	19.76	33.94	4.32	4.41	4.41
2008	22.42	33.65	12.73	18.85	20.06	34.46	4.40	4.49	4.49
2009	22.75	34.16	12.95	19.13	20.37	34.98	4.48	4.57	4.57
2010	23.09	34.68	13.18	19.42	20.68	35.51	4.57	4.66	4.66
2011	23.44	35.20	13.41	19.72	20.99	36.05	4.65	4.74	4.74
2012	23.79	35.74	13.64	20.02	21.31	36.60	4.73	4.82	4.82
2013	24.15	36.28	13.87	20.32	21.63	37.15	4.82	4.91	4.91
Escalation Rate of 1.5% thereafter									

(12)

The constant price and cost case assumes the continuance of product prices at December 31, 2001 and operating costs projected for 2002, and the continuance of current laws and regulations. Product prices have not been escalated beyond this date nor have operating and capital costs been increased on an inflationary basis. The annual revenue to be received from the production of the reserves was based on the following prices:

Oil	Edmonton Par Price 40° API ($/Bbl)	$	30.35
Natural Gas:	Alberta ($/MMBTU)	$	3.58
	Saskatchewan ($/MMBTU)	$	3.80
	British Columbia ($/MMBTU)	$	3.90
Natural Gas Liquids:	Ethane ($/Bbl)	$	9.91
	Propane ($/Bbl)	$	13.34
	Butane ($/Bbl)	$	15.47
	Pentanes ($/Bbl)	$	30.14

(13)

Capital expenditures required to achieve the future net revenue attributable to Proved Reserves in the escalated price and cost case were estimated to be $256.6 million, of which $94.7 million is required in 2002 and $33.2 million is required in 2003. Capital expenditures required to achieve the future net revenue attributable to Probable Reserves in the escalated price and cost case are estimated to be $146.2 million, of which $23.3 million is required in 2002 and $24.8 million is required in 2003.

(14)

Capital expenditures required to achieve the future net revenue attributable to Proved Reserves in the constant price and cost case are estimated to be $210.4 million of which $93.6 million is required in 2002 and $31.5 million is required in 2003. Capital expenditures required to achieve the future net revenue attributable to Probable Reserves in the constant price and cost case are estimated to be $125.9 million, of which $18.3 million is required in 2002 and $24.9 million is required in 2003.

(15)

"Estimated Future Net Production Revenue" has been calculated before deduction of income tax. **The present worth of estimated Future Net Production Revenue is not to be construed as fair market value.**

Estimated Future Net Pre-Tax Cash Flows Established Reserves[(1)]
Escalating Cost and Price Case
($000's except for production)

Year	Annual Production (MBOE)	Company Interest Revenue[(2)]	Royalty Burdens	Net Revenue After Royalty Burdens	Operating Expenses	Net Production Revenue[(3)]	Net Capital Investment	Net Cash Flow Before Income Taxes[(4)(5)]
2002	24,399	514,970	104,457	410,513	125,938	284,575	106,359	178,216
2003	24,692	589,474	119,780	469,694	132,208	337,486	45,588	291,899
2004	22,876	561,889	109,335	452,555	131,308	321,247	43,511	277,736
2005	20,683	513,592	97,039	416,553	127,491	289,062	14,198	274,864
2006	18,491	470,253	86,801	383,452	122,915	260,537	2,201	258,336
2007	16,430	426,571	77,405	349,166	117,344	231,822	3,010	228,813
2008	14,553	386,389	68,896	317,493	110,064	207,429	2,849	204,581
2009	12,984	351,184	61,297	289,887	104,026	185,861	3,315	182,547
2010	11,717	322,868	55,542	267,326	99,092	168,234	2,578	165,657
2011	10,747	299,798	51,358	248,440	92,323	156,118	2,445	153,673
Remaining	134,793	5,179,032	686,554	4,492,477	2,408,114	2,084,362	103,666	1,980,691
TOTAL:	312,365	9,616,020	1,518,464	8,097,556	3,570,823	4,526,733	329,720	4,197,013

Cash Flow Before Income Taxes Discounted to January[(5)] 1, 2002 at:

10%:	$	1,785,378
15%:	$	1,405,051
20%:	$	1,160,459

(1) Proved Reserves plus 50% Probable Reserves.

(2) Includes working interest revenue, royalty interest revenue and third party processing and other income.

(3) Company interest revenue less royalty burdens and operating expenses.

(4) Undiscounted.

(5) Cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.

Estimated Future Net Pre-Tax Cash Flows Established Reserves[(1)]
Constant Cost and Price Case
($000's except for production)

Year	Annual Production (MBOE)	Company Interest Revenue[(2)]	Royalty Burdens	Net Revenue After Royalty Burdens	Operating Expenses	Net Production Revenue[(3)]	Net Capital Investment	Net Cash Flow Before Income Taxes[(4)(5)]
2002	24,345	510,297	105,267	405,030	125,170	279,861	102,709	177,152
2003	24,396	514,492	105,493	408,999	127,671	281,328	44,010	237,318
2004	22,584	477,030	93,116	383,914	124,712	259,202	41,109	218,093
2005	20,353	429,537	80,889	348,648	118,143	230,505	14,379	216,126
2006	18,018	382,047	69,835	312,212	109,646	202,566	3,677	198,890
2007	15,928	338,224	60,552	277,672	101,625	176,047	3,228	172,819
2008	14,091	299,450	52,471	246,979	93,447	153,533	2,215	151,318
2009	12,619	268,541	45,939	222,602	87,928	134,675	1,969	132,706
2010	11,370	242,054	40,793	201,261	82,404	118,857	2,022	116,835

Year	Annual Production (MBOE)	Company Interest Revenue[2]	Royalty Burdens	Net Revenue After Royalty Burdens	Operating Expenses	Net Production Revenue[3]	Net Capital Investment	Net Cash Flow Before Income Taxes[4][5]
2011	10,445	221,358	37,027	184,331	75,908	108,424	2,335	106,089
Remaining	126,898	2,815,009	375,708	2,439,301	1,357,476	1,081,821	55,650	1,026,170
TOTAL:	301,047	6,498,039	1,067,090	5,430,949	2,404,130	3,026,819	273,303	2,753,516

Cash Flow Before Income Taxes Discounted[5] to January 1, 2002 at:

10%:	$	1,362,528
15%:	$	1,099,092
20%:	$	923,415

(1) Proved Reserves plus 50% Probable Reserves.

(2) Includes working interest revenue, royalty interest revenue and third party processing and other income.

(3) Company interest revenue less royalty burdens and operating expenses.

(4) Undiscounted.

(5) Cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.

APPENDIX B

INFORMATION REGARDING CELSIUS ENERGY RESOURCES LTD.

Business of Celsius

Celsius was an active oil and natural gas corporation carrying on business primarily in Alberta and northeastern British Columbia. Celsius' gross daily average production in the first nine months of 2002 was approximately 36% crude oil and NGLs and 64% natural gas, consisting of 2,280 Bbls/day of crude oil and NGLs and 24,280 Mcf/day of natural gas for a total of 6,327 Boe/day. See " Production History". See " Oil and Natural Gas Reserves of Celsius" for a summary of the oil, NGLs and natural gas reserves attributed to Celsius' properties.

Principal Properties of Celsius

The following paragraphs contain certain operational and reserves information for the principal properties of Celsius. The reserve estimates are based on the Sproule Celsius Report and the GLJ Celsius report, as applicable, each as described under " Oil and Natural Gas Reserves of Celsius" below:

Countess, Alberta

The Countess area, which is located approximately 100 kilometers southeast of Calgary, Alberta, was Celsius' most significant property. Celsius primarily operated its average working interest of 64% in 110 natural gas wells, 90 of which produce from the Milk River and Medicine Hat formations. In July 2002, gross daily average production was 3.8 MMcf/day of natural gas or 633 Boe/day net to Celsius. As at January 1, 2002, 1,723 MBoe of established reserves were attributed to Celsius' property interest in this area.

Verger, Alberta

Celsius had an average 32% working interest in the non-operated Verger area located approximately 130 kilometers southeast of Calgary, Alberta. The property's gross daily average natural gas production, which is produced primarily from the Milk River and Medicine Hat formations, was 2.2 MMcf/day or 364 Boe/day net to Celsius in July 2002. As at January 1, 2002, 2,407 MBoe of established reserves were attributed to Celsius' property interests in this area.

Rigel, British Columbia

Celsius owned various working interests ranging from 12% to 50% in the non-operated Rigel area located approximately 900 kilometers northwest of Calgary, Alberta. In July 2002, gross average daily production from this area was 1,025 Boe/day consisting of 943 Bbls/day of crude oil which is produced from the Cecil formation, 0.4 MMcf/day of natural gas and 15 Bbls/day of NGLs. As at January 1, 2002, 1,926 MBoe of established reserves were attributed to Celsius' property interests in this area.

Liege, Alberta

Celsius owned various working interests ranging from 6% to 22% in the non-operated Liege shallow natural gas property located approximately 800 kilometers northeast of Calgary, Alberta. Gross daily average natural gas production was 2.7 MMcf/day or 455 Boe/day net to Celsius in July 2002. As at January 1, 2002, 1,468 MBoe of established reserves were attributed to Celsius' property interests in this area.

Pine Creek, Alberta

Celsius had an average working interest of 26% in the non-operated Pine Creek area located approximately 400 kilometers northwest of Calgary, Alberta. This area produces liquids rich natural gas from the Bluesky and Gething zones with gross average daily production of 1.4 MMcf/day of natural gas and 174 Bbls/day of NGLs, for a total of 408 Boe/day net to Celsius in July 2002. As at January 1, 2002, 1,473 MBoe of established reserves were attributed to Celsius' property interests in this area.

Landholdings

The following table summarizes Celsius' land holdings at October 31, 2002:

	Undeveloped Acres		Developed Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	237,969	92,436	228,055	90,759	466,024	183,195
British Columbia	32,513	11,252	32,854	9,065	65,367	20,317
Saskatchewan	484	484	2,011	912	2,495	1,396
Total	270,966	104,172	262,920	100,736	533,886	204,908

(1) "Gross" acres means the total number of acres in which Celsius had an interest.

(2) "Net" acres means the aggregate of the percentage interests of Celsius in the gross acres.

Production History

The following table summarizes the historical average daily production from Celsius' producing properties for the periods indicated.

	Year ended December 31,	Nine months ended September 30,

	Year ended December 31, 2000	2001	2002
Oil (Bbls/day)	2,473	2,272	1,934
NGLs (Bbls/day)	288	348	346
Total liquids (Bbls/day)	2,761	2,620	2,280
Natural gas (Mcf/day)	26,133	24,874	24,280
Total Boe/day	7,177	6,766	6,327

Oil and Natural Gas Reserves of Celsius

The reserves of Celsius have been evaluated in two separate reserve reports prepared as of January 1, 2002. Gilbert Laustsen Jung Associates Ltd. ("GLJ"), a firm of independent petroleum engineers, prepared a report dated February 7, 2002 and effective January 1, 2002 with respect to the reserves of Celsius (the "GLJ Celsius Report"). Sproule Associates Limited ("Sproule"), a firm of independent petroleum engineers, prepared a report dated January 28, 2002 and effective January 1, 2002 with respect to the reserves of Canor Energy Ltd., which was amalgamated with, and continued as, Celsius effective January 1, 2002 (the "Sproule Celsius Report"). A summary of the information contained in each of the GLJ Celsius Report and the Sproule Celsius Report is contained below.

GLJ Celsius Report

In preparing the GLJ Celsius Report, GLJ obtained basic information from Celsius, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the GLJ Celsius Report is based, was obtained from public records, other operators and from GLJ's non-confidential files. The accuracy of all factual data supplied to GLJ by third parties was accepted by GLJ as represented and neither title searches nor field inspections were conducted.

The following is a summary, as at January 1, 2002, of Celsius' oil, NGLs and natural gas reserves attributable to the properties and the present worth value of the estimated future net cash flows associated with such reserves, based on constant price and cost assumptions, which is derived from the evaluations in the GLJ Celsius Report.

The tables summarize the data contained in the evaluations and as a result may contain slightly different numbers than the evaluations due to rounding. **All future cash flows are stated prior to provision for income taxes, interest, general and administrative expenses and indirect costs and after deduction of royalties and estimated future capital expenditures. It should not be assumed that the present worth of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of Celsius' oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein. The probable additional reserve volumes and the present value of estimated future cash flows from such reserves as shown in the tables have been reduced by a factor of 50% to account for risk.**

Oil and Natural Gas Reserves and Present Value of Estimated Future Cash Flows Excluding ARTC Based on Constant Price Assumptions

	Working Interest Reserves[(1)]		Present Value of Estimated Future Net Cash Flow, $000 Discounted at Rates of:
	Gross	Net	

	Working Interest Reserves(1)									
	Oil Mbbls	Gas MMcf	NGLs Mbbls	Oil Mbbls	Gas MMcf	NGLs Mbbls	0%	10%	15%	20%
Proved Reserves(2)										
Developed Producing(3)(4)	1,666	17,478	664	1,323	13,720	469	65,285	45,249	39,712	35,582
Developed Non-Producing(3)(5)	750	4,643	168	592	3,644	117	20,912	10,595	8,496	7,100
Undeveloped(6)										
Total Proved Reserves	2,416	22,121	832	1,915	17,364	586	86,197	55,844	48,208	42,682
Probable Reserves at 50%(7)	485	5,243	143	388	4,008	96	17,600	7,923	5,996	4,756
Established Reserves	2,901	27,364	975	2,303	21,372	682	103,797	63,767	54,204	47,348

(1) "Gross Reserves" are the remaining reserves owned by Celsius, before deduction of any royalties. "Net Reserves" are the gross remaining reserves of the properties in which Celsius has an interest, less all royalties and interests owned by others.

(2) "Proved Reserves" are those quantities of oil, natural gas and natural gas by-products, which, upon analysis of geological and engineering data, appear with a high degree of certainty to be recoverable at commercial rates in the future from known oil and natural gas reservoirs under current economic and operating conditions for reserves based on constant price and cost assumptions, and presently anticipated economic and operating conditions for the reserves based on escalated price and cost assumptions. There is relatively little risk associated with these reserves.

(3) "Proved Developed Reserves" are Proved Reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

(4) "Proved Developed Producing Reserves" are Proved Reserves which are presently being produced from completion intervals open for production in existing wells.

(5) "Proved Developed Non-producing Reserves" are Proved Reserves which are currently not being produced but do exist in completed intervals but not producing in existing wells, behind casing in existing wells or at minor depths below the present bottom of existing wells. These Proved Reserves are expected to be produced through the existing wells in the predictable future. These reserves are classified as Proved Developed Reserves since the cost of making such reserves available for production is relatively small compared to the cost of a new well.

(6) "Proved Undeveloped Reserves" are Proved Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where relatively major expenditures are required for the completion of these wells or for the installation of processing and gathering facilities prior to the production of these reserves. Reserves on undrilled acreage are limited to those drilling units offsetting productive wells that are reasonably certain of production when drilled.

(7) "Probable Reserves" are those reserves which may be recoverable as a result of the beneficial effects which may be derived from the future institution of some form of pressure maintenance or other secondary recovery method, or as a result of a more favourable performance of the existing recovery mechanism than that which would be deemed proved at the present time, or those reserves which may reasonably be assumed to exist because of geophysical or geological indications and drilling done in regions which contain proved reserves. **Probable reserve values for the petroleum and natural gas properties and the future net cash flow from probable reserves have been discounted by a factor of 50% to account for the risk associated with the probability of obtaining production from such reserves**.

(8) Natural gas reserves are reported at a base pressure of 14.65 pounds per square inch and a base temperature of 60º F.

(9) Prices for oil F.O.B. Edmonton are based upon 40º API oil having less than 0.4% sulphur. Prices for natural gas are based upon a base pressure of 14.65 pounds per square inch and base temperature of 60º F. The wellhead oil prices were adjusted for quality and transportation to reflect the actual

price to be received. The natural gas prices were adjusted, where necessary, only for heating values and the differing costs of service applied by various purchasers. The natural gas liquids prices were adjusted to reflect current prices received.

(10)

The constant price and cost case assumes the continuance of product prices and operating costs projected for 2002, and the continuance of current laws and regulations. Product prices have not been escalated beyond these dates nor have operating and capital costs been increased on an inflationary basis. The annual revenue to be received from the production of the reserves was based on the following prices which were supplied by Celsius:

Oil	Edmonton Par Price 40º API ($/Bbl)	$	31.58
Natural Gas:	Alberta ($/MMBTU)	$	3.75
Natural Gas Liquids:	Propane ($/Bbl)	$	25.88
	Butane ($/Bbl)	$	25.88
	Pentanes ($/Bbl)	$	31.96

(11)

Capital expenditures required to achieve the future net revenue attributable to Proved Reserves in the constant price and cost case are estimated to be $3,320,000, of which $1,802,000 is required in 2002 and $485,000 is required in 2003. Capital expenditures required to achieve the future net revenue attributable to Probable Reserves in the constant price and cost case are estimated to be $1,103,000 (50% risked), of which $176,000 (50% risked) is required in 2002 and $582,000 (50% risked) is required in 2003.

(12)

"Estimated Future Net Production Revenue" has been calculated before deduction of income tax. **The present worth of estimated Future Net Production Revenue is not to be construed as fair market value.**

Estimated Future Net Pre-Tax Cash Flows Established Reserves Excluding ARTC[(1)]
Constant Cost and Price Case
($000's except for production)

Year	Annual Production (MBOE)	Company Interest Revenue[(2)]	Royalty Burdens	Net Revenue After Royalty Burdens	Operating Expenses	Net Production Revenue[(3)]	Net Capital Investment	Net Cash Flow Before Income Taxes[(4)(5)]
2002	1,168	27,582	6,829	20,753	4,142	16,612	1,980	14,632
2003	1,009	23,652	5,793	17,859	3,776	14,084	1,067	13,017
2004	858	20,109	4,777	15,333	3,332	12,001	256	11,745
2005	707	16,497	3,801	12,696	2,920	9,777	49	9,728
2006	599	13,940	3,154	10,786	2,585	8,201	47	8,155
2007	509	11,740	2,552	9,189	2,410	6,779	38	6,742
2008	421	9,634	2,013	7,621	2,231	5,390	24	5,367
2009	350	7,909	1,558	6,351	2,054	4,297	10	4,288
2010	298	6,671	1,267	5,404	1,840	3,564	34	3,530
2011	253	5,621	1,058	4,563	1,665	2,898	24	2,875
Remaining	2,264	49,773	9,315	40,456	15,837	24,616	894	23,718
TOTAL:	8,436	193,128	42,117	151,011	42,792	108,219	4,423	103,797

Cash Flow Before Income Taxes Discounted[(5)] to January 1, 2002 at:

10%: $63,767
15%: $54,204
20%: $47,438

(1)

Proved Reserves plus 50% Probable Reserves.

(2)

Includes working interest revenue, royalty interest revenue and third party processing and other income.

(3) Company interest revenue less royalty burdens and operating expenses.

(4) Undiscounted.

(5) Cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.

Sproule Celsius Report

In preparing the Sproule Celsius Report, Sproule obtained basic information from Celsius, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the Sproule Celsius Report is based, was obtained from public records, other operators and from Sproule's non-confidential files. The accuracy of all factual data supplied to Sproule by third parties was accepted by Sproule as represented and neither title searches nor field inspections were conducted.

The following is a summary, as at January 1, 2002, of Celsius' oil, NGLs and natural gas reserves attributable to the properties and the present worth value of the estimated future net cash flows associated with such reserves, based on constant price and cost assumptions, which is derived from the evaluations in the Sproule Celsius Report.

The tables summarize the data contained in the evaluations and as a result may contain slightly different numbers than the evaluations due to rounding. **All future cash flows are stated prior to provision for income taxes, interest, general and administrative expenses and indirect costs and after deduction of royalties and estimated future capital expenditures. It should not be assumed that the present worth of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of Celsius' oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein. The probable additional reserve volumes and the present value of estimated future cash flows from such reserves as shown in the tables have been reduced by a factor of 50% to account for risk.**

Oil and Natural Gas Reserves and Present Value of Estimated Future Cash Flows Excluding ARTC
Based on Constant Price Assumptions

	Working Interest Reserves(1)						Present Value of Estimated Future Net Cash Flow, $000 Discounted at Rates of:			
	Gross			Net						
	Oil Mbbls	Gas MMcf	NGLs Mbbls	Oil Mbbls	Gas MMcf	NGLs Mbbls	0%	10%	12%	15%
Proved Reserves(2)										
Developed(3)	758.4	47,714	160.3	667.6	39,315	108.0	101,929	62,521	58,505	53,508
Undeveloped(4)	23.7	6,848	57.1	19.7	5,149	38.7	12,144	6,493	5,872	5,103
Total Proved Reserves	782.1	54,562	217.4	687.3	44,464	146.7	114,073	69,014	64,377	58,611
Probable Reserves at 50%(5)	212.0	3,009	41.4	186.3	2,326	28.5	8,293	3,122	2,723	2,270
Established Reserves	994.1	57,571	258.8	873.6	46,790	175.2	122,366	72,136	67,100	60,881

(1)

"Gross Reserves" are the remaining reserves owned by Celsius, before deduction of any royalties. "Net Reserves" are the gross remaining reserves of the properties in which Celsius has an interest, less all royalties and interests owned by others.

(2)

"Proved Reserves" are those quantities of oil, natural gas and natural gas by-products, which, upon analysis of geological and engineering data, appear with a high degree of certainty to be recoverable at commercial rates in the future from known oil and natural gas reservoirs under current economic and operating conditions for reserves based on constant price and cost assumptions, and presently anticipated economic and operating conditions for the reserves based on escalated price and cost assumptions. There is relatively little risk associated with these reserves.

(3)

"Proved Developed Reserves" are Proved Reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

(4)

"Proved Undeveloped Reserves" are Proved Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where relatively major expenditures are required for the completion of these wells or for the installation of processing and gathering facilities prior to the production of these reserves. Reserves on undrilled acreage are limited to those drilling units offsetting productive wells that are reasonably certain of production when drilled.

(5)

"Probable Reserves" are those reserves which may be recoverable as a result of the beneficial effects which may be derived from the future institution of some form of pressure maintenance or other secondary recovery method, or as a result of a more favourable performance of the existing recovery mechanism than that which would be deemed proved at the present time, or those reserves which may reasonably be assumed to exist because of geophysical or geological indications and drilling done in regions which contain proved reserves. **Probable reserve values for the petroleum and natural gas properties and the future net cash flow from probable reserves have been discounted by a factor of 50% to account for the risk associated with the probability of obtaining production from such reserves**.

(6)

Natural gas reserves are reported at a base pressure of 14.65 pounds per square inch and a base temperature of 60º F.

(7)

Prices for oil F.O.B. Edmonton are based upon 40º API oil having less than 0.4% sulphur. Prices for natural gas are based upon a base pressure of 14.65 pounds per square inch and base temperature of 60º F. The wellhead oil prices were adjusted for quality and transportation to reflect the actual price to be received. The natural gas prices were adjusted, where necessary, only for heating values and the differing costs of service applied by various purchasers. The natural gas liquids prices were adjusted to reflect current prices received.

(8)

The constant price and cost case assumes the continuance of product prices and operating costs projected for 2002, and the continuance of current laws and regulations. Product prices have not been escalated beyond these dates nor have operating and capital costs been increased on an inflationary basis. The annual revenue to be received from the production of the reserves was based on the following prices which were supplied by Celsius:

Oil	Edmonton Par Price 40 API ($/Bbl)	$	31.58
Natural Gas:	Alberta ($/MMBTU)	$	3.75
Natural Gas Liquids:	Pentanes ($/Bbl)	$	31.96
	Propane ($/Bbl)	$	25.88
	Butane ($/Bbl)	$	25.88

(9)

Capital expenditures required to achieve the future net revenue attributable to Proved Reserves in the constant price and cost case are estimated to be $2,126,000 of which $1,317,000 is required in 2002 and $413,000 is required in 2003. Capital expenditures required to achieve the future net revenue attributable to Probable Reserves in the constant price and cost case are estimated to be $445,000 (50% risked), of which $154,000 (50% risked) is required in 2002 and $500 (50% risked) is required in 2003.

(10)

"Estimated Future Net Production Revenue" has been calculated before deduction of income tax. **The present worth of estimated Future Net Production Revenue is not to be construed as fair market value.**

Estimated Future Net Pre-Tax Cash Flows Established Reserves Excluding ARTC[1]
Constant Cost and Price Case

($000's except for production)

Year	Annual Production (MBOE)	Company Interest Revenue(2)	Royalty Burdens	Net Revenue After Royalty Burdens	Operating Expenses	Net Production Revenue(3)	Net Capital Investment	Net Cash Flow Before Income Taxes(4)(5)
2002	1,253	27,611	5,992	21,619	5,479	16,141	1,471	14,671
2003	1,174	25,731	5,550	20,181	5,207	14,975	414	14,561
2004	1,051	23,062	4,979	18,084	4,698	13,387	350	13,037
2005	892	19,567	4,144	15,423	4,210	11,214	8	11,206
2006	768	16,855	3,489	13,366	3,775	9,593	50	9,543
2007	690	15,167	3,059	12,108	3,579	8,529	175	8,354
2008	585	12,779	2,475	10,304	3,226	7,078		7,078
2009	448	9,578	1,722	7,856	2,617	5,240		5,240
2010	395	8,374	1,486	6,888	2,406	4,482	15	4,467
2011	339	7,187	1,225	5,962	2,196	3,767		3,767
Remaining	3,251	66,434	10,904	55,529	24,991	30,531	88	30,441
TOTAL:	10,848	232,345	45,025	187,320	62,384	124,937	2,571	122,365

Cash Flow Before Income Taxes Discounted(5) to January 1, 2002 at:

10%:	$72,136
15%:	$60,881
20%:	$52,968

(1) Proved Reserves plus 50% Probable Reserves.

(2) Includes working interest revenue, royalty interest revenue and third party processing and other income.

(3) Company interest revenue less royalty burdens and operating expenses.

(4) Undiscounted.

(5) Cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.

7,000,000 Trust Units

Trust Units

PROSPECTUS
November 25, 2002

Joint Book-Running Managers

Salomon Smith Barney
CIBC World Markets

RBC Capital Markets
BMO Nesbitt Burns
Lehman Brothers
Scotia Capital
UBS Warburg
Putnam Lovell NBF
TD Securities
Canaccord Capital USA
Raymond James

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