ENERPLUS RESOURCES FUND
Form SUPPL
November 26, 2002

QuickLinks -- Click here to rapidly navigate through this document

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.

TABLE OF CONTENTS

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.

10

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)

	Crude Oil	Natural Gas Liquids	Natural Gas	Total	Estimated Future Net Cash Flow[1] Undiscounted	Estimated Future Net Cash Flow[1] 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)

	Crude Oil	Natural Gas Liquids	Natural Gas	Total	Estimated Future Net Cash Flow[1] Undiscounted	Estimated Future Net Cash Flow[1] 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.**

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

13

	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."

Enerplus Resources Fund

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

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.

44

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	Natural Gas % of Estimated Gross Production(1)	Crude Oil Contracted Volumes	Crude Oil % of Estimated Gross Production(1)
	(MMcf/day)		(Bbls/day)	
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